THE SAFETY OF HAZARDOUS LIQUID PIPELINES (PART 2): INTEGRITY MANAGEMENT

(111–128)

HEARING

BEFORE THE

SUBCOMMITTEE ON

RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS

OF THE

COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
HOUSE OF REPRESENTATIVES

ONE HUNDRED ELEVENTH CONGRESS

SECOND SESSION

July 15, 2010

Printed for the use of the
Committee on Transportation and Infrastructure

U.S. GOVERNMENT PRINTING OFFICE

57–487 PDF WASHINGTON : 2010

For sale by the Superintendent of Documents, U.S. Government Printing Office
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July 14, 2010

SUMMARY OF SUBJECT MATTER

TO: Members of the Subcommittee on Railroads, Pipelines, and Hazardous Materials

FROM: Subcommittee on Railroads, Pipelines, and Hazardous Materials Staff

SUBJECT: Hearing on "The Safety of Hazardous Liquid Pipelines (Part 2): Integrity Management"

PURPOSE OF THE HEARING

The Subcommittee on Railroads, Pipelines, and Hazardous Materials is scheduled to meet on Thursday, July 15, 2010, at 10:00 a.m., in room 2167 of the Rayburn House Office Building to receive testimony on pipeline operators' management of the safety of hazardous liquid pipelines, known as integrity management. The hearing is the third in a series of hearings that the Subcommittee will conduct on pipeline safety.

BACKGROUND

According to the Pipeline and Hazardous Material Safety Administration (PHMSA), there are more than 170,000 miles of onshore and offshore hazardous liquid pipelines (about 200 operators) in the United States, which carry more than 75 percent of the nation's crude oil and around 66 percent of its refined petroleum products. Of the more than 170,000 miles of hazardous liquid pipeline, about 55,000 miles are major crude oil trunk lines, which range in diameter from eight inches to 48 inches. Associated with these trunk lines in several locations is significant crude oil tankage, and about 30,000 to 40,000 miles of crude gathering lines, which are smaller lines that gather the oil, gas, and water from many wells, both onshore and offshore, and connect to the larger trunk lines. In addition, there are about 95,000 petroleum product lines, flow lines/piping associated with well operations, and produced water pipelines (containing contaminated water following oil, gas, and water separation). Many hazardous liquid pipelines also transport highly volatile liquid, which is hazardous liquid that will form a vapor cloud when released to the atmosphere.

inspection (ILI), hydrostatic testing, or direct assessment.[7] Alternative assessment methods can be employed if they can be shown to be effective.[8]

ILI, also known as "pigging", is used to detect wall thickness and the amount of corrosion in the line providing the operator with information on operability and safety. Pigs have been an integral part of maintaining pipelines since the beginning of the 20th Century. The earliest devices were basic utility pigs, better known as scraper pigs. Updated versions are still in use today, scraping and scrubbing pipes to remove liquid and solid buildup.[9]

Since 1965, oil pipeline operators have used technologically advanced versions that measure and record problems in the pipes. Known as "smart pigs", these mechanical devices check for potential problems such as corrosion, dents, and cracks, and provide information to a pipeline operator so that corrective measures can be taken.

Smart pigs are cylinder-shaped electronic devices inserted into the pipe and then propelled by the flowing oil. They detect loss of metal or deformations in the pipeline. Pipeline operators use this data to determine where potential problems are, which are then investigated further and repaired as needed.

New technologies have made smart pigs even more efficient and effective. Pigs that use magnetic flux leakage (MFL) technology, ultrasonic measurements, and geometric tools are among the most common smart pigs used today.

There are two types of MFL technologies in use: standard and transverse flux inspection (TFI). TFI operates the same way as standard MFL, except that the magnetic field it generates is turned 90 degrees. Standard MFL pigs are best at detecting cracks and other defects while TFI pigs are better at detecting seam-related corrosion.

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[7] Michael Baker Jr., Inc., *Pipeline Corrosion Final Report,* U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety (November 2008), at 33, http://primis.phmsa.dot.gov/iim/docstr/FinalReport_PipelineCorrosion.pdf.

[8] *Id.* Operators must advise PHMSA 90 days in advance of conducting an assessment with an alternative technology. *See also* PHMSA, *Implementing Integrity Management for Hazardous Liquid Operators: Frequently Asked Questions* (October 15, 2009), at 17, http://primis.phmsa.dot.gov/iim/faqs.htm.

[9] "Utilizing a Smarter Pig," *In the Pipe: News from the Pipeline Industry* (February 2006).

MFL can detect corrosion by sensing magnetic leakage. First, it initiates a magnetic field in the pipeline. If there are any flaws in the pipeline wall, some of the magnetic field will escape. Sensors onboard the pigs detect and measure that leakage. Smart pigs equipped with MFL technology can determine whether the corrosion is internal or external, and they can also measure for changes in the thickness of the walls.

Measurements are made when the pigs emit ultrasonic signals whose echoes are timed and compared with data to determine the wall's thickness. The same ultrasonic technology can detect longitudinal cracks, crack-like defects, and longitudinal weld defects.

Smart pigs can also identify deformations, dents, or obstructions by measuring the bore of the pipe for uniformity. These tools utilize mechanical arms or electro-mechanical instruments.

Pigging has the potential to provide for 100 percent coverage, in contrast to other assessment methods. However, certain larger defects may be missed and defects may not be sized correctly. This is why it is important that each pipeline operator utilize the best assessment tool, and that may require more than one tool.

Hydrostatic testing involves filling a section of pipe with water and increasing the pressure to a level significantly above the normal operating pressure.[10] The primary purpose of hydrostatic testing is to detect and remove joints of the pipeline that contain defects (including corrosion pits or cracks) by causing them to leak or rupture while the pipeline is filled with water.[11]

Direct assessment involves obtaining information from existing records on pipelines, taking measurements of the pipeline, excavating and examining the pipe, and analyzing post-assessment data.[12] Direct assessment is often used for unpiggable pipelines where an interruption of service would be impractical.[13]

III. BACKGROUND ON ALYESKA PIPELINE COMPANY

In 1968, oil was discovered at Prudhoe Bay in the North Slope, located in northern Alaska between the Brooks Range Mountains and the Beaufort Sea (part of the Arctic Ocean). A consortium of oil companies planning to produce the oil determined that a pipeline offered the best means to transport crude oil from the North Slope to a navigable port in southern Alaska where it could be shipped by tanker to refineries in the continental United States. The pipeline route would cover 800 miles from Prudhoe Bay to the port of Valdez, the northernmost ice-free port in the United States.[14]

The Alyeska Pipeline Service Company was established in 1970 and charged with designing, constructing, operating, and maintaining the Trans Alaska Pipeline System, commonly called TAPS. Pipeline construction began in March 1975 and was finished in June 1977. Crude oil began flowing

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[10] *Id.* at 35.
[11] *Id.*
[12] *Id.* at 37.
[13] *Id.* at 36.
[14] *See* Alyeska's website at http://www.alyeska-pipe.com.

in the pipeline on June 20, 1977, and the first tanker filled with North Slope crude oil left Valdez on August 1, 1977.[15]

The 48-inch diameter steel pipeline runs 800 miles and crosses three mountain ranges and over 800 rivers or streams; 420 miles of the pipeline is elevated above ground to keep the permafrost from melting. The volume of oil flowing through the pipeline has decreased from a peak of 2.1 million barrels per day (bpd) in 1988 to about 650,000 bpd in 2010. Alaska today supplies nearly 14 percent of the United States' domestic crude oil production.

The consortium of companies that own TAPS today includes:

BP Pipelines (Alaska) Inc.:	46.93 percent
ConocoPhillips Transportation Alaska, Inc.:	28.29 percent
ExxonMobil Pipeline Company:	20.34 percent
Koch Alaska Pipeline Company, LLC:	3.08 percent
Unocal Pipeline Company:	1.36 percent[16]

BP has a strong role in directing Alyeska's operations. Alyeska's president, Kevin Hostler, spent 27 years with BP, most recently as senior vice president of BP's global human resources organization. Before that, Hostler was head of BP's subsidiary in Columbia. According to recent press reports, a top BP Alaska official asked, in light of the Gulf disaster, whether it is a good idea to have Mr. Hostler, a "BP executive", running TAPS, "where BP can exert cultural and economic influence through the president of [Alyeska] as well as its ownership share, in directions that are not good for the safety and the integrity of [the pipeline]." The BP Alaska official said the fact that both companies are plagued by the same safety and management concerns is evidence of a "pervasiveness of a BP leadership culture that is focused on cost cutting that reduces operational integrity." Last Wednesday, one day after the press report surfaced, Alyeska's president resigned, amid allegations that Alyeska – at the direction of BP and Mr. Hostler – was making dangerous cost cuts to the pipeline's integrity management program and falsely inflating the amount of money Alyeska spent on pipeline corrosion.[17] According to Alyeska, Mr. Hostler had already planned to retire at the end of this year.

PHMSA has also been concerned about corrosion in Alyeska's pipelines. In March 2006, internal corrosion on a 34-inch low-stress pipeline, owned by BP Exploration, caused a 5,000 barrel crude oil spill (212,252 gallons spilled) on the North Slope of Alaska. The oil spill was the worst in the history of oil development on Alaska's North Slope, and went undetected for five days before a BP oilfield worker detected the scent of hydrocarbons during a drive through the area. A few months later, in August 2006, a second leak was discovered while BP was inspecting the Eastern Operating Area segment of the pipeline. Field inspection of the leak site revealed multiple holes at a single location, contributing to an estimated spill of about 1,000 gallons of processed crude oil.

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[15] *Id.*
[16] *Id.*
[17] Jason Leopold, "Dangerous Cost Cuts at Alyeska Pipeline: Yet Another Example of How BP Runs Things," *Truthout*, http://www.truth-out.org/alyeska-pipeline-yet-another-example-how-bp-runs-things61097. *See also* Jason Leopold "Alyeska CEO Steps Down Following Truthout Exposé," *Truthout*, http://www.truth-out.org/alyeska-ceo-resigns-following-truthout-expose61134.

During the course of its investigations of the 2006 BP pipeline failures, PHMSA became concerned about the safety of another pipeline (Affected Pipeline) operated by BP and Alyeska because of its shared operating and internal characteristics to the failed BP lines and because the Affected Pipeline had not been cleaned or internally inspected. According to BP, the pipeline is "one of the most important pipelines on the North Slope. The entire flow from the Prudhoe Bay Unit is transported through this pipeline just before it enters the Trans Alaska Pipeline."[18]

Since 2006, PHMSA has – on numerous occasions—urged both BP and Alyeska to comprehensively assess the structural integrity of the Affected Pipeline, repair any defects that were identified, and conduct other work to correct significant corrosion problems or fully replace the pipeline. According to PHMSA, these measures were needed "to protect life, property, and the environment from potential hazards associated with the Affected Pipeline." BP and Alyeska were initially unresponsive to PHMSA's concerns. As a result, on June 20, 2008, PHMSA issued a corrective action order to BP and Alyeska directing them to take immediate action.[19] According to PHMSA, BP and Alyeska now plan to replace the pipeline by the end of this year.

More recently, PHMSA has been focused on a May 25, 2010, incident at Alyeska's Pump Station 9, located near Delta Junction, Alaska. On the morning of May 25, Alyeska briefly shut down the Trans Alaska Pipeline to perform routine maintenance and testing on the fire control system at Pump Station 9 (the site of several previous maintenance failures, including a 2007 fire). Similar maintenance and testing activities had been completed during pipeline slowdowns at other pump stations in early May. During the third and final fire system test procedure at Pump Station 9, which simulated an electrical fire, the station lost power. The redundant power supplies also failed. As a result, Alyeska's operations control center in Anchorage lost visibility to and control of Pump Station 9; meaning, the control center could not see what was happening at the pump station. According to Alyeska's internal investigation report, the station was designed so that a loss of power would cause the station's relief valves to open allowing crude oil to flow into relief tanks so that the pipeline is not inadvertently over pressured. Because of that, crude oil began pumping from the pipeline into an overflow tank, Tank 190. Tank 190 is able to hold 55,000 to 60,000 barrels of oil; prior to the release, it had about 22,000 barrels in it. For a yet-to-be-determined length of time after the pump station lost power, the crude oil filled Tank 190 and then spilled over the top. It was not until the oil spilled over the top that Alyeska personnel who were performing the fire testing observed that crude oil was discharging from the vents on Tank 190 onto the ground.[20] PHMSA estimates that from the time the pump station went "blind" to the control center in Anchorage, about 33,000 barrels (1,386,000 gallons) of oil had filled the tank and another 5,000 barrels (210,000 gallons) spilled onto the ground.

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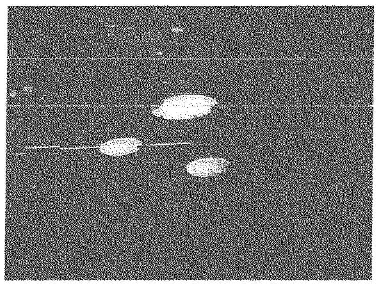
[18] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.
[19] *Id.*



According to Alyeska, a number of significant incidents on TAPS over the last several years, demonstrate a trend of operational discipline deficiencies similar to those involved with the Tank 190 overfill incident.[21] The report also notes that while the operations command center did not have visibility of Pump Station 9 during the overflow incident, monitoring upstream pressure at Pump Station 8 would have provided insight to the controllers that pipeline pressure was dropping, indicating flow to Pump Station 9.

After evaluating the facts surrounding the incident, PHMSA's Associate Administrator for Pipeline Safety issued a corrective action order to Alyeska stating, "I find that the operation of TAPS [the Trans Alaska Pipeline System] without corrective action measures would be hazardous to life, property and the environment." According to PHMSA:

> Additionally, after considering the age of the pipeline facility, the particular circumstances surrounding this failure and crude oil spill, the failure to actuate certain valves around the time of the spill, suspected problems with the electrical power system, the proximity of the pipeline and breakout tank to an HCA, the hazardous nature of the crude oil being transported, the pressure required for transporting the material when the line is operational, Alyeska's intention to restart the pipeline without the relief capacity provided by Tank 190, the uncertainties as to the cause of the failure, and the ongoing investigation to determine the cause of the failure, I find that a failure to issue this order expeditiously to require immediate corrective action would result in likely serious harm to life, property, and the environment.[22]

The corrective action order required Alyeska to implement a variety of safety measures, including locating personnel at the pump station around the clock to monitor activities.[23] Alyeska is in the process of removing personnel from its pump stations along the 800-mile pipeline, as part of its Strategic Reconfiguration plan that, according to Alyeska, concentrates on reducing physical

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[21] These significant incidents include a tank vent fire at Pump Station 9 on January 6, 2007; a Remote Gate Valve leak on January 9, 2007; an overfill near loss of Tank 190 at Pump Station 9 on March 22, 2007; energy isolation near loss events at Pump Station 9 in October 2008; Sadelrochit Stream Gas Excursion at Pump Station 1 on January 15, 2009; and a pipeline overpressure event at Pump Station 9 on July 19, 2009. *See also* Alyeska Pipeline Service Company, *TK190 Overfill Incident Root Cause Analysis Report and Post Accident Review* (June 22, 2010).
[22] *Id.*
[23] *Id.*

infrastructure and simplifying operations and maintenance. The plan calls for electrification of pump stations and installation of new control systems for the pipeline. After reconfiguration, each pump station will be manned from Alyeska's operations control center in Anchorage. According to Alyeska's prior president, David Wight, who also served as President of BP Amoco Energy Company: "When we are done, Strategic Reconfiguration will shave millions of dollars from the annual cost of moving oil from Prudhoe Bay to Valdez. Our workers still face many challenges as we modernize the pipeline. However, I am confident that they will succeed in extending TAPS' economic life while maintaining the highest safety, integrity and environmental standards."

In addition to the two corrective action orders, PHMSA has issued 13 notices of probable violation to Alyeska since 2002 alleging violation of various Federal regulations, including significant deficiencies in Alyeska's integrity management and corrosion control programs; 10 notices of amendment, which identify shortcomings in Alyeska's plans and procedures under PHMSA regulations; and 10 warning letters regarding deficiencies in Alyeska's programs. PHMSA has proposed a total of $1,754,300 in civil penalties as a result of the alleged failures.

One of the most recent violations was for what PHMSA characterizes as a "near miss incident" in January 2010. BP was using natural gas to push a cleaning pig through its pipeline (an abnormal and potentially dangerous operation). Two breakout tanks at Alyeska's Pump Station 1 were over pressurized due to the rapid influx of natural gas into TAPS, which caused Alyeska's tanks' relief vents and "blow out" type hatches to open and release flammable vapors. Following the incident, Alyeska restarted the pipeline without verifying and confirming system integrity. According to the corrective action order, Alyeska didn't even conduct a visual inspection of the tanks before restarting the system.[24] Alyeska is challenging the proposed violation.

IV. Background on Enbridge – U.S. Operations

Enbridge Pipelines Inc. operates the world's longest and most sophisticated crude oil and petroleum products pipeline system. The 1,900-mile Lakehead System (the U.S. portion of the world's longest pipeline) has operating for 59 years and is the primary transporter of crude oil from Western Canada to the United States. The system spans from the international border near Neche, North Dakota, to the international border near Marysville, Michigan, with an extension across the Niagara River into the Buffalo, New York area. It consists of approximately 3,500 miles of pipe with diameters ranging from 12 to 48 inches; 60 pump station locations; and 64 crude oil storage tanks with a capacity of about 11.6 million barrels. Total deliveries on the Lakehead System averaged 1.62 million bpd in 2008, meeting approximately 72 percent of Minnesota refinery capacity; 64 percent of the greater Chicago area; and 68 percent of Ontario's refinery demand.

Enbridge's North Dakota System is a 330-mile crude oil gathering and 620-mile interstate transportation system that gathers crude oil from points near producing wells in 22 oil fields in North Dakota and Montana. Most deliveries from the approximately 161,000 bpd North Dakota System are made at Clearbrook, Minnesota, which provides connections with the Lakehead System and a third-party pipeline that transports crude oil to refineries in the Minneapolis/St. Paul area.

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[24] *Id.*

In response to increasing crude oil production in the region, Enbridge recently completed a 51,000 bpd expansion in early 2010. Enbridge is proposing additional expansions of the North Dakota System.

The Enbridge Toledo Pipeline connects to the Lakehead System at Stockbridge, Michigan, and travels southward to two refineries in the Toledo, Ohio, area. This 35-mile pipeline has a capacity of 100,000 barrels per day in heavy crude oil service and became available for service in February 1999.

The first continuous delivery of western Canadian crude oil was initiated in early March 2006 through Enbridge's Spearhead Pipeline to Cushing, Oklahoma. The 650-mile, 22- and 24-inch diameter pipeline historically operated in south-to-north service, but Enbridge bought the pipeline and reversed its flow to provide Canadian crude oil producers and shippers with access to markets in the Mid-Continent and southern United States. Enbridge recently expanded the Spearhead Pipeline, increasing the average annual capacity from 125,000 bpd to 190,000 bpd.

The Mid-Continent System comprises the Ozark and West Tulsa pipelines and storage terminals at Cushing, Oklahoma, and El Dorado, Kansas. The Mid-Continent System includes more than 480 miles of crude oil pipelines, with average deliveries in 2008 totaling 231,000 bpd. It has 96 individual storage tanks ranging in size from 55,000 to 575,000 barrels. A recent expansion of the Cushing Terminal increased storage capacity on the system to 16 million barrels.

In addition to Enbridge's many wholly owned pipelines and facilities, the company has interest in several other liquids pipelines across the United States.[25]

PHMSA reports that, since 2002, it has issued one corrective action letter and one proposed corrective action letter to Enbridge. The most recent corrective action letters stems from a pipeline rupture that occurred on January 8, 2010, resulting in the release of about 3,000 barrels (126,000 gallons spilled) of crude oil near Neche, North Dakota. PHMSA found that continued operation of the line without corrective action measures, including a mandatory reduction in pressure on the pipeline stemming from the Canadian border to Superior, Wisconsin, would be hazardous to life, property, and the environment.

PHMSA proposed another corrective action order (and $2,405,000 in civil penalties) to Enbridge stemming from a fatal accident that occurred on a 34-inch crude oil pipeline on November 28, 2007, near Clearbrook, Minnesota.[26] The oil spill started with a leak the size of a pinhole, and erupted into an explosion and towering flames, killing two Enbridge workers and resulting in more than $2 million in property damage.

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[25] *See* Enbridge Pipeline's Internet web site at http://www.enbridgeus.com/.

[26] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.

PHMSA found that Enbridge failed to: (1) follow its written procedures regarding welds+ends couplings used by its field personnel for pipeline replacement; (2) ensure that the pipeline was sufficiently anchored before installing the couplings; review the work performed by its personnel; (3) remove multiple ignition sources around the area the work was being performed; and (4) ensure that personnel received proper training and were qualified to conduct the repairs. PHMSA also found that Enbridge had operated the pipeline in excess of the design pressure of the weld+ends couplings as determined by the manufacturer and outlined in its recommended installation instructions.[27]

In addition to the $2,405,000 in civil penalties proposed as a result of the Clearbrook, Minnesota incident, PHMSA has proposed $121,500 in civil penalties for various violations since 2002, including the failure of Enbridge to conduct certain inspections and maintain certain records. PHMSA has also issued six notices of amendment, which identify shortcomings in Enbridge's plans and procedures under PHMSA regulations; and seven warning letters regarding deficiencies in Enbridge's programs.[28]

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[27] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_26149.html.
[28] *Id.*

WITNESSES

Mr. Richard Adams
Vice President, U.S. Operations, Liquids Pipelines
Enbridge Pipelines

The Honorable David Guttenberg
House District 08 – Fairbanks, Alaska
Alaska State House Minority Whip

Mr. Greg Jones
Senior Vice President, Technical Support Division
Alyeska Pipeline Service Company

Mr. Richard Kuprewicz
Public Member, PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee

The Honorable Cynthia Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation

HEARING ON THE SAFETY OF HAZARDOUS LIQUID PIPELINE (PART 2): INTEGRITY MANAGEMENT

Thursday, July 15, 2010

HOUSE OF REPRESENTATIVES, SUBCOMMITTEE ON
RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS,
COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE,
WASHINGTON, DC.

The Subcommittee met, pursuant to call, at 10:00 a.m., in room 2167, Rayburn House Office Building, Hon. Corrine Brown [Chairman of the Subcommittee] presiding.

Ms. BROWN OF FLORIDA. The Subcommittee on Railroads, Pipelines, and Hazardous Materials will come to order.

The Subcommittee is meeting today to hear testimony on pipeline operation management of the safety of hazardous liquid pipelines, more common known as "integrity management." This hearing is the third in a series of oversight hearings the Subcommittee will hold as we look toward reauthorizing the Department's pipeline safety program.

On February 1, 2000, in the wake of several tragic pipeline ruptures, PHMSA issued a Final Ruling, requiring pipeline operators to develop and implement a written Integrity Management Program. Under the program, operators are required to identify all of their pipeline segments that could affect a high-consequence area, such as a high-population area, an environmentally sensitive area, evaluate the integrity of such pipeline segments and repair and report certain defects identified as a result of these evaluations.

A lot of successes came out of the Integrity Management Program. For example, operators have reported to PHMSA that they have made more than 31,000 repairs to hazardous liquid pipeline segments, that if left unaddressed, could have resulted in a spill. Of these, about 7,000 detects were considered to be so serious that immediate repairs were required under the regulations. Another 25,000 detects had to be repaired within a 60- to a 180-day time period.

This is a real success, and I anticipate that we will see similar successes from the gas Integrity Management Program, but there is always room for improvement, and that is why we are here today.

I hope we can get some of the areas that might need some refined tuning up front. We do have concerns about the Integrity Management Program of BP Exploration and Alyeska Pipeline Service. BP, as evidenced by the Deepwater Horizon spill, has a long history of taking too many risks and cutting corners to pursue economic growth and profits. BP Exploration was invited to this hearing, but could not attend.

Recent press reports allege that Alyeska, at the direction of BP, which owns almost 50 percent of the company, is following in BP's footsteps by making dangerous cuts in safety and inflating the amount of money the company is spending on corrosion control. A day after these reports surfaced, the Alyeska President, who has worked for BP for almost 27 years, announced his resignation. Alyeska stated that his retirement was already planned, but the timing of this most recent announcement is questionable.

I am concerned about a few recent incidents at Alyeska, one of which was a near miss indicident that resulted in the release of flammable vapors. According to PHMSA's Corrective Action Order, Alyeska did not verify the safety of the pipeline before it restarted operations.

Another incident occurred at Pump Station 9, which lost power during firing testing. As a result, the station dropped off the radar screen at Alyeska Pipeline's control center. Crude oil began to flow without anyone realizing it, and in the end, 22,000 barrels of oil flowed into a relief tank and then spilled over, spilling another 5,000 barrels of oil onto the ground. Alyeska seemed to minimize the significance of this spill in its written testimony, stating that, because the oil spilled into secondary containment, no environmental damage or injuries occurred. The fact is, while the lining of the containment area is designed to prevent oil from leaking into the soil, when crude oil meets the air, it releases toxic gas. These gases have been proven to cause significant health effects in humans, and workers involved in the cleanup of this spill suffered the highest level of exposure.

This last month, the National Institute of Environmental Health Sciences testified before Congress that, historically, the workers involved in the cleanup have reported the highest level of exposure and most acute symptoms when compared to subjects exposed in different ways. So I would caution Alyeska against minimizing the impact of this incident.

With that, I welcome today's panelists, and thank you for joining us. I look forward to this hearing.

I am pleased to introduce the Honorable Cynthia Quarterman, who is the Administrator of the Pipeline and Hazardous Material Safety Administration.

Welcome. We are pleased to have you here with us this morning. Your entire written statement will appear in the record. Madam Administrator, please proceed.

STATEMENT OF THE HON. CYNTHIA L. QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Ms. QUARTERMAN. Thank you. Good morning.

Chairwoman Brown, Ranking Member Shuster, if he should show up, and Members of the Subcommittee, thank you for the opportunity to appear today.

Secretary LaHood, the employees of Pipeline and Hazardous Material Safety Administration, and the entire Department of Transportation all share public safety as their top priority. The Department is committed to preventing spills on all pipelines through aggressive regulation, oversight and enforcement.

PHMSA is focused on improving the integrity of pipeline systems and reducing the risk of pipeline failure. Integrity Management Programs were created to ensure pipeline integrity in areas with the highest potential for adverse consequences, promote a more rigorous and systematic management of pipeline integrity and risk, improve the government's prominent role in the oversight of integrity plans, and assure the public's confidence in the safe operation of the Nation's pipeline network.

PHMSA's regulations consist of prescriptive measures pipeline operators must follow and perform at standards that consider a pipeline's unique characteristics and operating conditions. Together, these regulations seek to prevent the leading causes of pipeline failure, and require operators to implement corrosion prevention, leak detection, and leak containment technologies.

Integrity Management Programs ensure pipeline operators adequately identify, evaluate, and address risks of the entire pipeline systems. The integrity management rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the liability of hazardous liquid pipelines in or near high-consequence areas. That rule also emphasizes the prompt detection of leaks through the monitoring of operational parameters and engineered leak detection systems. In addition, Integrity Management Programs are intended to improve an operator's analytic processes and risk management. We are proud to say integrity management is working.

Since this program has been mandated, all hazardous liquid pipelines within high-consequence areas have been assessed. That assessment resulted in the identification and repair of over 35,000 dangerous conditions. In addition, 86 percent of hazardous liquid pipeline mileage has been assessed, and an additional 78,000 anomalies outside of high-consequence areas have been remedied.

PHMSA has also ensured that operators comply with corrosion standards through inspection and aggressive enforcement. Since 2000, PHMSA has issued 657 probable violations or procedural inadequacy notices involving corrosion, and has proposed $1.7 million in fines.

PHMSA has taken unprecedented steps to inform the public and all stakeholders about the protections provided by the Integrity Management Program and PHMSA's oversight. PHMSA has an integrity management Web site to provide information to the public on the rule as well as PHMSA's oversight of the program. This publicly accessible Web site includes hundreds of frequently asked questions to explain the rule's provisions and PHMSA's expectations. This transparency helps PHMSA improve its oversight and increase its stakeholder understanding and evaluation of its program.

PHMSA looks forward to working with Congress to address issues related to hazardous liquid pipeline safety, including finding ways to be more effective in preventing pipeline failures and mitigating the effect of any failure. PHMSA very much appreciates the opportunity to report on hazardous liquid pipeline Integrity Management Programs.

I would be happy to answer any questions that you might have today. Thank you.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Walz, you can ask any questions or make any opening statement that you want.

Mr. WALZ. Thank you, Madam Chairwoman, and thank you for holding this important hearing. I certainly wish more of my colleagues were here.

Ms. Quarterman, thank you for coming back here again. You have been a regular up here, and I appreciate that. Just a couple of thoughts for you.

In 2006, the Inspector General over at DOT reported concerns about operators' overreliance on integrity management assessments. Is that a concern of yours or have we fixed that in the subsequent 4 years?

Ms. QUARTERMAN. I don't believe there were any specific recommendations that came out as a result of the IG's findings. However, the program did go in and try to remediate the concerns that were addressed by the Inspector General by following up on reporting errors that had been made by operators, and now it is a regular part of our inspection protocol that they should review reports that have been made and whether the data has been accurate or not.

Mr. WALZ. OK. Tell me through this procedure, if you can, Ms. Quarterman: How do I know of the integrity and of the safety of the pipelines in southern Minnesota today? How would I go about finding that out? How do I know? How do I verify? How do I assure that somebody is not just checking the block on a form? How do I know that that integrity is real, in the ground, and how do we verify that?

Ms. QUARTERMAN. Well, the operator is the first person responsible for ensuring that the integrity of a pipeline is sound. Historically, the program had produced a series of regulations that were very prescriptive in nature and essentially required or allowed a pipeline operator to just comply with those minimal technical requirements. The inspectors at the time would go out and do what you said, essentially check a box to make sure that those prescriptive requirements were met.

The Integrity Management Program was intended to create a systematic approach for pipeline operators, one in which the inspectors could check what they were doing. The Integrity Management Programs should take into account the individual characteristics of each operator's pipeline—size, location, product being shipped, all of that.

As a result of that program being in place, we have created a new inspection protocol, and I will tell you our Integrity Management Program inspections usually include three to five engineers on a team, and they go out for 3 to 4 weeks. This is the inspection protocol that they go through. It is extremely thorough, extremely complicated.

Mr. WALZ. This comes to a good point, and I was going to ask: Are all pipeline operators created equal? Obviously not in terms of size, product and all that. Are they created equal in their culture of safety?

Ms. QUARTERMAN. Unfortunately not.

Mr. WALZ. OK. Does the Integrity Management Program compensate for that in terms of assuring public safety if we do have—for lack of a better term—a bad actor in this business? Are we capturing that or does it come back to the issue, as you said, of fundamentally when I asked the question of southern Minnesota, and you said it basically falls upon the operator?

Ms. QUARTERMAN. Well, that is the first line of defense. We do have inspectors to go out and inspect, obviously. The purpose of the Integrity Management Program was to do just what you said, to try to help embed into the industry a culture of safety by requiring them to look at the details of their operations and go through an assessment of their pipeline and of the situation surrounding their pipelines to come up with the best plan for their particular pipelines as opposed to just abdicating responsibility altogether and saying, OK, well, our pipeline meets a certain recommended practice in terms of the type of steel, and that is it.

Mr. WALZ. Is it unfair for us to draw conclusions to Deepwater Horizon and how the integrity management there was given over to the operators, obviously, to a point where we didn't catch an error? Is that unfair? Is it apples to oranges here or is it similar in terms of the culture and the redundancies of safety to say, yes, Deepwater Horizon should show us something about pipelines?

Ms. QUARTERMAN. Well, I think there are lessons for all of us to learn from the Deepwater Horizon incident.

One of those lessons—and I know there is an ongoing investigation, but based on the public information that has been made available is the role of contractors in industry, and it is not just in offshore operations. It is true across all industries, and it is also true in the pipeline industry and one in which we have to take a very close look at how operators are managing their contractors.

We are reviewing opportunities to create a further system for quality management systems to ensure the contractors that are hired by companies meet the same requirements as those people who are on the ground every day—or who should be on the ground.

Mr. WALZ. Very good. Thanks, Ms. Quarterman.

I yield back.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Shuster.

Mr. SHUSTER. I thank the Chairwoman, and I welcome the administrator. You have become a regular guest with us here. I appreciate your coming up here and spending time with us.

I really don't have any questions for you. I think I will probably ask you many times over all the questions that I have.

I am not going to read my whole statement, but I would like for the entirety to be put in the record.

I would like to point out that, of course, today's hearing is on Integrity Management Programs and that pipelines are only required by law to test the high-risk areas, but in practice, many of them do much more than that. Our next witness from Enbridge will talk about how only 40 percent of their system is in high-risk areas, but they perform internal inspections on nearly 100 percent of their pipelines. Only 40 percent of the Transatlantic Pipeline passes through high-risk areas, but they hold the entire pipeline to the high-risk standard. So I think that is important to point out.

Again, thank you, Administrator Quarterman, for being here, and I look forward to hearing our other panel of witnesses.

I yield back.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Cummings.

Mr. CUMMINGS. Thank you very much, Madam Chairlady, and thank you for holding this hearing.

Ms. Quarterman, let me just ask you a few questions.

According to your Web site, since the integrity management rule was implemented in 2001—is that right? Was it 2001?

Ms. QUARTERMAN. It essentially started around 2000, 2001, 2002. There was a layering of who it was applied to.

Mr. CUMMINGS. Since that time, pipeline operators have made almost 32,000 repairs to hazardous liquid pipeline segments that could have affected a high-consequence area if there was a release. How does PHMSA verify that each of these repairs has, in fact, been made and made to a standard that would be satisfactory?

Ms. QUARTERMAN. During our integrity management inspection process, we review the data that the operators have that show where these particular anomalies were and the fact if they were repaired or not. There may be spot-checking on a particular repair, but we certainly are not there every day to review it as a repair is done. We do, during our inspection process, do a thorough review of those particular incidents where they should have done a repair to ensure that it has been performed.

Mr. CUMMINGS. But is that spot-checking? I mean do you actually go out and look at each situation?

Ms. QUARTERMAN. We don't have the personnel to go out and look at each situation.

Mr. CUMMINGS. So it is just a matter of taking somebody's word. Is that basically it?

Ms. QUARTERMAN. On an annual basis, the management of each pipeline operator has to certify the reports of repairs that have been performed on their pipeline. So, while we can't go out there individually, if it were the case that someone fraudulently wrote down that they had done a repair, we would be, obviously, able to go after them on criminal charges.

Mr. CUMMINGS. Well, you know, one of the things that we have seen with BP is—and I am trying to put this nicely. There have been some questionable integrity issues, and the sad part is, when these issues come along, they cannot only be harmful—they can be deadly—and I guess sometimes management has to say to themselves, you know, do I take the risks? I mean is profit more important than safety?

I guess I am just asking: Has there ever been a time when folks actually went out and even spot-checked, I mean at any time? Do you follow me?

Ms. QUARTERMAN. Yes, I follow you.

Mr. CUMMINGS. We are talking about verifying. Just going back to Ronald Reagan, you know, you can believe them, but you have got to verify.

I guess the only reason I am raising this is because of the situation that we find ourselves in right now where we assume—see, sometimes in this country, I think we assume too much. We assume, assume, assume, and we assume that when the rubber meets the road that everything is going to be fine. Then when the rubber comes to meet the road, we discover there is no road. I think that is what happened in Katrina. I think that is what has happened here.

Also, as Chairman of the Coast Guard Subcommittee, I talk about this whole idea of making sure that there is integrity in all of our systems. So I was just wondering.

Go ahead.

Ms. QUARTERMAN. Yes, we do do field inspections that spot-check repairs. When an inspector goes in to look at the integrity management plan, they look at the list of locations where these significant anomalies were found as well as the repair record to double check and make sure that there is support for the fact that a repair was done. In addition, there are spot-checks done in the field.

Mr. CUMMINGS. You know, the IRS, when you talk to them about why they audit people, there are certain things that they put in their computer, certain information that triggers inspections. I was wondering, is there any triggering information, mechanisms, data, whatever, that would automatically cause alarm bells to go off and for you all to do these spot checks you are talking about other than your routine ones?

Ms. QUARTERMAN. Well, certainly, if in looking at the paperwork something were to appear to be amiss—and I can tell you there has been an instance where some welding records were amiss, and we are following up on that—then they would go and check it.

So, yes. The inspectors are engineers, and they are trained to look at this data, and if something looks weird—for example, if a record keeps repeating itself over and over and over again and it is clear it is not addressing the issue—then, yes, there are triggering mechanisms.

Mr. CUMMINGS. Thank you very much, Madam Chair.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Teague.

Mr. TEAGUE. Yes. Thank you, Madam Chairwoman, for having this meeting and for letting me be here.

A couple of questions, I guess, were already asked, but I wanted to ask them a little bit differently.

In talking about the integrity test that we run, is there a standard frequency of time that we run those tests depending upon the size of the line or the pressure of the line?

Ms. QUARTERMAN. Under the Integrity Management Program, there was a requirement that operators do an assessment, most of which were inline inspections with pigging instruments within a certain time period. That time for most operators ended either at the end of 2008 or at the beginning of 2009, and this was in high-consequence areas, and then they had to reassess again 5 years later. They had to start with their riskiest 50 percent and then do the last 50 percent, look at those assessments and determine which ones, based on our standards, were the most problematic, fix those first, and go from there. Most operators are now in that reassessment period, meaning that they are beginning to do a second run of those high-consequence areas.

Mr. TEAGUE. Do we know the way that it is set up in that 5-year time frame? Is every single line tested?

Ms. QUARTERMAN. Every line that is in a high-consequence area must have a test, and I said 5 years. Five years is the outlying number. If an operator determines that, because of the attributes of their particular line that it should be tested more frequently than that, then they should do that. That would be part of their plan. In 5 years—or I think it is 68 months at the outside—they must be retested.

Mr. TEAGUE. But we know that every line is tested at least once every 5 years?

Ms. QUARTERMAN. Right. In high-consequence areas, yes.

Mr. TEAGUE. Are we ever on site when they test the lines?

Ms. QUARTERMAN. Not always, no. Occasionally, we go after, usually, the assessment has been done to see what has occurred and what anomalies have been found and how they have remediated it.

Mr. TEAGUE. When do we get the test results? Like, if they test the line today, when do you get the test results?

Ms. QUARTERMAN. We do not receive the data in-house at the time it is tested. When we go out on an inspection, we review their records there, so we don't have a repository of their data.

Mr. TEAGUE. When you do go out and do the on-site testing, do you just go to their office and review the test results from that or are you actually there like when they put the pig in the line and drive down the road and be there when they pick the pig up?

Ms. QUARTERMAN. Most of what we do is reviewing the paper records. We do do spot tests, and we are there on occasion when people are pigging their line. We simply don't have the resources to be at every assessment.

Mr. TEAGUE. But you are at some on-site tests to see them put the pig in and see them take the pig out?

Ms. QUARTERMAN. Yes. Yes.

Mr. TEAGUE. Are there any other tests or requirements to the pipeline as to the type of material, the wall thickness or anything else when it is installed?

Ms. QUARTERMAN. Before a pipeline is installed, this is in the construction phase, it has to go through a hydrostatic test to ensure they can operate above the maximum allowable operating pressure on the line.

Mr. TEAGUE. You said a while ago that we had collected a large amount of money, millions of dollars in fines. What happens with that money?

Ms. QUARTERMAN. That money is returned to the Treasury.

Mr. TEAGUE. OK. You know, there was a question asked about how comparable this should be to the Deepwater Horizon, and was it apples and oranges. You know, I do think that it is apples and oranges. I don't think there is much more comparison to this and the Deepwater Horizon than there is to this and driving unless, maybe, the Pipeline and Hazardous Material Safety Administration—we are not in any comparison to MMS or anything in the way that we are operating.

I mean, if there are comparisons to pipeline safety and Deepwater Horizon, is there a comparison also to Pipeline and Hazardous Material Safety Administration and MMS?

Ms. QUARTERMAN. MMS regulates drilling operations, and PHMSA regulates pipeline operations. The differences between the two are that, in the instance of a drilling operation, as we have seen it in Deepwater Horizon, there is the opportunity for a blowout, which has an unlimited flow of oil. In the instance of a pipeline, it is sort of like a garden hose in that it has a finite amount—well, it is not like a garden hose in that it is finite, but it does have a finite amount of product in it. There are valves that can be shut off, so there is a finite amount of spill that can occur as a result of an incident.

Mr. TEAGUE. OK. In regards to our testing and spot-checking and stuff like that, do you think we are a lot more efficient than MMS apparently was in what they were doing?

Ms. QUARTERMAN. I can't really speak to that.

Mr. TEAGUE. Thank you.

Ms. BROWN OF FLORIDA. Ms. Richardson.

Ms. RICHARDSON. Thank you, Madam Chair, and thank you for having this very timely hearing in the series that we have been going through.

Administrator, thank you for being here. I have about four or five questions if we could go through them as quickly as possible.

From 2000–2008, the U.S. DOT Pipeline and Hazardous Material Safety Administration reported on its Web site that 21 oil spills occurred in my district, California's 37th Congressional District. Between 2005–2009, the national average stated that 68 percent of the total incidences were reported to your administration but were not made public via your Web site. My questions are:

How many oil spills or incidents have occurred in the 37th Congressional District? I would like to know the number of what was reported and not reported.

Ms. QUARTERMAN. I will have to get you the details for your particular district. I can tell you that the reporting requirements have changed and have been reduced over time, so now 5-barrel spills are being reported, and maybe that is the difference between the data, but I am not sure about that. We would have to verify that for you.

Ms. RICHARDSON. Who are they reported to besides your Web site? Are the Members notified?

Ms. QUARTERMAN. They are reported to us, and we put it on the Web site, and it is available to the public. If you would like to have notification of every instance that occurs in your district, we would be happy to do that.

Ms. RICHARDSON. Well, I think, for this Committee's jurisdiction, it might be helpful to have an ongoing report on a periodic basis and then, that way, Members who have this interest would have the ability to check, but I would like my district's information.

Ms. QUARTERMAN. Absolutely.

Ms. RICHARDSON. My next question is: Do you believe that 21 spills are large enough to change the current process and consider that that is probably not an acceptable number and how communities should be maybe more engaged in what is happening?

Ms. QUARTERMAN. Well, I think there should be no spills, and that is our goal and what we are working towards. I can tell you that the number of spills has been reduced by about 50 percent over the past decade or so.

Ms. RICHARDSON. These were 21 within this decade, 2000–2008.

Ms. QUARTERMAN. I am just saying from the beginning of the decade until today that the number of spills has gone down dramatically, but it has not gone to zero, which is our ultimate goal.

In terms of how communities can be involved, there are a number of grants that PHMSA provides to communities, especially those interested in being involved in the pipeline safety program, one of which is a base grant to a State if they would like to assist by having an agreement with PHMSA. California is a State that has an agreement with PHMSA to oversee the pipelines within their State. On top of that, there are State damage prevention grants that are provided to States so they can help ensure that pipelines are not damaged within their communities.

There are also 811, or One Call Grants, that are useful, because one of the leading causes of pipeline incidents is excavation damage, and that is to assist communities in providing information to the public about calling 811, so before they dig, they know the location of a pipeline. There are also——

Ms. RICHARDSON. I am down to a minute and 30 seconds. If you could supply that to us, that would be sufficient.

Ms. QUARTERMAN. Absolutely.

Ms. RICHARDSON. I have several other questions along the same line.

After the first round of operator-performed assessments that were completed in February of 2009, pipeline operators reported to your organization that they had made 31,855 repairs in high-consequence areas. My question is:

How many repairs were performed in my district, and do you have a map or data that informs people of exactly where the repairs are made?

Building on that same question, in my district we contain 643 total pipeline miles, and 558 of those consist of hazardous liquid pipeline. My question is:

Are these pipelines regulated? Have they been inspected? What type of inspection has been done, and what is the condition that has been found?

Then finally—I have got about 34 seconds—I recently had the opportunity this last weekend to spend some time in the Gulf for about 2–1/2 days. One of the things that I saw that seemed to be a problem is we could have had the companies better required to have the resources in place to handle a spill better. I don't know if that is a shared resource that companies in the area all have, you know, those devices. So my question would be and if you could supply it to this Committee:

What materials are required? If in the event you were to have an incident, what are those that you know of?

One of the things we found out in the Deepwater Horizon situation is we found out that many of the things we were using weren't effective. So to what degree has your group documented? What resources would be needed? Are they being stockpiled appropriately in the areas that need them? Because we didn't have enough booms. We are still in, you know, day 80-something, and we don't have enough boom material. We don't have enough skimmers. They are now getting this air-conditioned kind of mat material, and we shouldn't be doing that after the incident. We should know what is needed, and it should be sufficiently available so we can respond.

So, if you could provide this Committee that information, it would be helpful. Thank you very much for your time.

Ms. QUARTERMAN. Sure. Thank you.

Ms. BROWN OF FLORIDA. Would you like to respond to any part of her questions?

Ms. QUARTERMAN. Well, as to the specifics with respect to the district, we will provide that to the record.

On the oil spill response, I will say that PHMSA issued a safety advisory a few weeks ago to all of the onshore oil pipeline operators. That is our responsibility to make sure that those plans are in place, asking them to review their oil spill response plan in light of Deepwater Horizon to make sure that their worst case spill is accurate and that the personnel that they have identified and the resources they have identified are available and capable of responding to a spill if it is a worst case spill. We gave them an exception for, obviously, a response that is necessary for Deepwater Horizon, but we want to make absolutely sure that the oil spill plans that are in existence for the onshore pipelines are the best they can possibly be.

Ms. RICHARDSON. Madam Chair, if I could just respond to that very briefly.

I think, though, the problem is we need more than a plan. We need to know: Do you physically have the boom? Do you physically have the skimmers? Do you physically have whatever it is, and is someone within your organization checking to see that it is there? Because, if there is anything we have learned, it is that we need more than a plan. We need to know that it is not just a plan and that it is actually something that is ready to do.

Thank you, though, and I do appreciate your efforts in these tough times.

Ms. BROWN OF FLORIDA. Thank you, Ms. Richardson.

If the Members would like, we could have another round.

Mr. Sires.

Mr. SIRES. Thank you, Madam Chair, for holding this hearing, and I apologize if this question was asked before.

I come from a very congested area. Just to give you an idea, the town that I live in is 1 square mile, and we have 50,000 people, so pipelines going through some of this area is one of my biggest concerns, especially in a congested area.

I know that we check the pipelines every 5 years. I was just wondering if it is prudent in heavily congested areas to increase that and make it less than 5 years. I was just wondering what you think of that. I am concerned about the safety feature of it, the safety factor of it.

Ms. QUARTERMAN. I am concerned as well.

A congested area, as you referred to, a highly populated area—and I live in one as well—is one that would be considered a high-consequence area. In those instances, the operator should be considering whether it is appropriate to do more frequent assessments of those pipelines in those areas given the situations that they run into in that particular area. Whether or not doing it more frequently would make a bigger difference, I don't know. We haven't looked at that issue.

Mr. SIRES. Can you handle more frequent inspections? You know, can you handle the paperwork and all the things that go with it?

Ms. QUARTERMAN. Well, now I am talking about assessments. This is something that the operators, themselves, do with these tools.

Mr. SIRES. Right.

Ms. QUARTERMAN. Then we go in and inspect after the fact. We would probably require more inspectors in order to do more frequent inspections, absolutely.

Mr. SIRES. What can we do in Congress to make that happen for you? Don't ask for too much.

Ms. QUARTERMAN. Well, additional resources are always welcome.

Mr. SIRES. Just additional resources?

It is just that, you know, in my district, every time you dig something up, there is a problem. I am talking now as a former local mayor. Even to do a sidewalk, you have got to worry about cables and so forth. So, as to the fact that excavating in many of these areas may not damage the pipe right then and there, it might just make it where, down the line, it would be a problem. So that is when I ask you, in terms of heavily populated areas, that I think we need to make it more often. I think I pointed out to you the Edison accident years ago. That is how dangerous it is.

So I don't have any further questions. Thank you very much.

Ms. BROWN OF FLORIDA. Thank you.

Ms. Quarterman, according to your Web site, pipeline operators report 32,000 defects were found outside of high-consequence areas.

Is this reporting a requirement by regulations or is it voluntary? If operators find defections outside of that area, the high-consequence area, do the operators have to repair these defects in accordance with the integrity management rule? If not, do you think they should report on it and repair these defects?

Ms. QUARTERMAN. There is no requirement that they report that information. I imagine that people are reporting it to get credit to show that they were doing, not just what is required by the rule, but above and beyond what is required by the rule.

There are no requirements that those anomalies that have been found in areas out of high-consequence areas meet the terms of the integrity management rule. I would say that a prudent operator and one with a strong safety culture, once they find the indication of an anomaly of great concern, would repair those. If not and there were an incident, they would, obviously, be subject to great penalties from PHMSA, and hopefully, everybody is aware of that.

Ms. BROWN OF FLORIDA. What do you think would be our responsibility as we rewrite the law? Not the rule. Our responsibility as lawmakers as we move forward.

Ms. QUARTERMAN. Well, I think you are doing the right thing to hold this hearing to ask questions about how the program is working and how we might improve it.

We are at a point in time when we have identified that 44 percent of oil pipelines could affect an HCA. It appears as though operators have assessed about 86 percent of those pipelines, so the vast majority—86 percent of all pipelines. Sorry. The vast majority of all pipelines, hazardous liquid pipelines, have been assessed at least once.

We are in the process of a reassessment. Forgive me for this analogy, but I think of it a little bit like a mammogram. You have the baseline, and then the next assessment shows you the change that has happened and whether there is cause for concern.

At the end of this reassessment period, which would be 5 years from the end of the first assessment, I think we will have a much better picture of pipelines in those high-consequence areas, and we should consider what the next step should be for the other areas.

Ms. BROWN OF FLORIDA. You mentioned that DOT issued enforcement letters for 85 percent of all the integrity management inspections. What are the top three or four problems DOT has found?

Ms. QUARTERMAN. The number one problem—and there were about four or five that were close to the top—was the evaluation of their leak detection capability to protect the HCAs. We found that operators had not done enough to ensure that their leak detection system was adequate. That was number one.

Shortly after that, we were concerned that they had not done an adequate analysis and documentation supporting their program. There was not enough to show that they had gone into great detail considering, for example, what is a high-consequence area.

We initially put out some baseline information about the locations of high-consequence areas, and the requirement was that operators would go the next step with respect to their particular line and the neighborhoods associated with it and look deeper and not just at the immediate vicinity; but if there is, for example, a water intake point where, you know, liquid flows down that would flow down further away from the area that we have identified, they would do a deeper analysis of that, and we found some inadequacies in those kinds of analyses.

Third, we were concerned about the process that they used to qualify personnel for assessment results review. This is a key part of the analysis. They run the inline inspection tools or do hydrostatic tests or whatever. It is extremely technical analysis that is shown, and it is very difficult to determine what exactly you are being shown in one of these runs. We were concerned that the people who were reviewing the runs because we essentially put up this new requirement, and everybody in industry had to then get up to speed in order to do that, and some of the people were not as qualified as we might like to see them.

So those were the top three.

Ms. BROWN OF FLORIDA. Last question.

If we find a company that is not in compliance, what kinds of penalties or fines do we have? What kind of enforcement mechanisms are in place?

Ms. QUARTERMAN. We do have penalties that were instituted in the PIPES Act of 2006. I would say those penalties have not been updated according to inflation over time. At the moment, we are probably maxing out on the penalties at about $100,000 a day, I think.

Ms. BROWN OF FLORIDA. OK.

Congressman Young.

Mr. YOUNG. Thank you, Madam Chairman.

My interest in this, of course, is the TAPS line, the Alyeska line. For the Committee, I am not going to ask her any questions. I am just going to suggest respectfully—and this is a creation of myself—that a little history, a little institutional memory, in this body does serve.

When we discovered oil in Alaska—when I say "we," it was discovered in Alaska by the oil companies—at that time, we had to pass the Trans-Alaska Pipeline. In this Congress in 1973, the industry itself wanted to, in fact, operate the pipeline. They do not do so. Contrary to what some of your staff have said, they own parts of the pipeline, but they do not run it. It is a separate entity, entitled by itself to run itself, and it does run itself by itself. There have been three incidences in that pipeline where there have been, in fact, spills.

One was being shot at. It took them seven shots, by the way, with a .338 Magnum. The problem that arose then was the fact that they thought it was a terrorist attack, which was right after 9/11. It was an irate individual who just decided to do it. If we could have stopped it at that time, instantly, there would have been no spill at all, but the automatic shutoff valve did work. The oil did come through the bullet hole, and by the time they got done, there was a spill. That was not the fault of the pipeline.

In the recent one that we have had, it worked. There was a human error factor. There was a breaker that was forgotten to be checked. The oil that did spill at the pump station was contained, as it was designed. It worked excellently, and there was no environmental damage. I have to say that again because, according to the report I read from your staff, there was. In fact, there was not.

Thirdly, I take great pride in this pipeline. It was built in 1976. It was built in 3 years, and it has supplied oil to the United States of America. It has all gone to America but two tankers. This pipeline has been under scrutiny constantly, and to somehow tie this in with BP I think is piling on.

We have a lot of great Americans who work for BP, and for some reason now, if you work for BP, you are a bastard. I am saying that is totally wrong. These are honorable people. The company may have done something wrong in the Gulf. I am not going to defend them in that area, but as far as the Alyeska Pipeline, I am quite excited about their record, and I know some people in this room who are going to testify later will say, Well, they have transferred people out of Fairbanks. Yes, they have. I do not like that, but in reality they are a business, and they have the opportunity and the responsibility to make sure that the business is run correctly, and they have not had any damages.

So let's not tie this Alyeska Pipeline in. They have supplied 17 billion barrels of oil to America—to Americans—to be utilized there, and they have run this operation extraordinarily well. I just want everybody to understand that. This company is dependent on itself. It may be funded by oil companies, but it is independent on itself, and that is the way it was constructed.

If you want to check the record, Ralph Nader called me the most powerful freshman Congressman in Congress because he didn't think I would vote for that, to have an independent agency run the pipeline and not the oil companies, themselves.

So I just want to remind people, when we start pointing fingers, make sure you point them in the right direction. This is not BP's problem. It is not a problem. This is a good pipeline. It has supplied us with 17 billion barrels of oil without any incident at all.

I yield back the balance of my time.

Ms. BROWN OF FLORIDA. I ask unanimous consent that Mr. Young be permitted to participate in today's hearing and sit and ask questions of the witness.

Without objection.

Ms. Richardson.

Ms. RICHARDSON. Well, after that, I will tell you. Welcome, Mr. Young.

Mr. YOUNG. I always add a little bit of spice to any Committee meeting. I will guarantee you that.

Ms. RICHARDSON. All right. Well, I won't speak to Alaska because I don't live in Alaska, and I haven't studied it, but I have been to the Gulf, and I have been studying that, and I don't think you can call it "honorable" at all.

Ms. Administrator, I just want to go back to my question and make sure we have your commitment on two things.

One, the raw data of all spills on your Web site today are perceived by laymen—I am not a chemist. I am not a biologist. I am not an engineer— so, in my mind, they are basically unreadable—a bunch of codes—but it is not really clear. In fact, the only ones that can really be read are the incidences and spills that are referenced as "significant" or as "serious incidences."

It is my understanding that the Committee has brought this to your attention and that there has been a verbal understanding that you will make the changes and make sure that all of the spills and incidences which are listed on the Web site are readable in layman's terms and are clearly, obviously, available to this Committee on a regular basis; is that correct?

Ms. QUARTERMAN. That is correct. The Committee has brought it to our attention that it could be improved. We appreciate those comments, and we will ensure that the data is accessible. The purpose of it is for the public to be able to review it and understand what it means, and if it is not doing that, we need to fix it.

Ms. RICHARDSON. Thank you.

Then my last question is: It has also been brought to my attention that, with your department, many of the regulations and standards that have been adopted don't provide a specific certain date that the regulations must be met.

Then, further, if someone in the public or even in my office, in a government office, contacts and wants to get a copy of a particular standard, they are told that they have to buy the information from an industry association, and that seems completely contrary. Specifically, what I am referencing are standards—when we were looking into the issue, we couldn't find the API Standard 1130. When we contacted your organization, the response was that staff had to purchase it from API.

Safety advocates have raised this concern with your organization on numerous occasions, including hearings in this Committee. They have been told that they have to purchase the document from the industry association. Needless to say, I think that is absurd. So I would also appreciate your looking into that and the information being available to the public, whether it be electronic or that we be able to get from your department.

Ms. QUARTERMAN. We had talked about this a little bit at the last hearing.

The standards that you are referring to are industry standards across, for example, engineering organizations, and they are ones that are—there is a statute that requires—or encourages the government to use these standards. OMB encourages them to use it. It is not just a PHMSA issue. It is a government-wide issue. Any organization or government agency, regulatory agency, that oversees an industry has adopted these kinds of standards.

I agree with you that it would be more pleasing if they were available for free to anyone who would want to see them. They are not available for free. We will commit to looking at ways in which we might make some of the standards that have been adopted more available to the public, and we have done that in many instances by either explaining in detail what is in the standards or providing them at our offices for people to come and inspect them or having them available electronically.

Ms. RICHARDSON. Well, it is my understanding my office was told to buy it from an industry. So we look forward to your updating and improving that system.

Thank you very much.

Ms. BROWN OF FLORIDA. Ms. Quarterman, there have been incidents, to my understanding, involving both Alyeska and BP, and BP does own 47 percent of the company, and their budget and management decisions have to be approved. I don't know.

Do you have the information that you can get to the Committee on the incidents that have occurred?

Ms. QUARTERMAN. Do you mean all pipeline safety incidences associated with the Trans Alaska Pipeline System?

Ms. BROWN OF FLORIDA. Yes.

Ms. QUARTERMAN. I think that we can do that to the extent that they are available.

The most recent incident is still under investigation, and we are in the process of an enforcement action with respect to that one, but as to any of the historic incidents, we can certainly give you information on those, and there have not been many.

Ms. BROWN OF FLORIDA. And you said there have not been many?

Ms. QUARTERMAN. There have not been many.

Ms. BROWN OF FLORIDA. Well, we have found out from the Gulf we only need one. You know, one is just too many, and one can destroy the environment and destroy industry. So what we have to do is—we can't afford not even one.

Ms. QUARTERMAN. I agree.

Mr. YOUNG. Madam Chairman.

Ms. BROWN OF FLORIDA. Yes, sir.

Mr. YOUNG. Madam Chairman, may I suggest respectfully, the recent incident, what they are investigating, was human error. A breaker was not checked. That is what happened. Then, unfortunately, there is the double standard there. The breaker was not checked by a human being.

Again, though, the oil that was spilled there was collected as it was designed to do so. It has been built to do that in containment areas. This is a classic example of something that is engineered to do the right thing. That is why I am so defensive about the line. We built it. We designed it, and it has worked through two earthquakes, one an 8.8, and it did not have any spills.

Now we had this spill caused by human error that was, in fact, contained as it should be. There was no dispersement of any oil. So there was no accident in the pipeline, per se.

Is that correct, Madam Quarterman?

Ms. QUARTERMAN. I am sorry. What is your question?

Ms. BROWN OF FLORIDA. There was an investigation, is my understanding.

Mr. YOUNG. Yes. The investigation is why the human error occurred but not on the pipeline, itself.

Ms. QUARTERMAN. The investigation is ongoing.

Mr. YOUNG. Yes.

Ms. BROWN OF FLORIDA. Yes.

Thank you for your testimony and you will get back with us and answer those additional questions.

What I would like to do is to call up the second panel. We have a vote, or should we just wait until we come back?

Mr. YOUNG. Madam Chair, start it because it will be 45 minutes, don't you think?

Ms. BROWN OF FLORIDA. Let's call up—it is just one vote.

Mr. YOUNG. One vote or two votes?

Ms. BROWN OF FLORIDA. Let's have the one vote and then come right back. I thank you all very much, and the second panel, you can take your seat and we will get started. We can stand informally in recess, and we are looking forward to a lively discussion of the second panel. All right.

[Recess.]

Ms. BROWN OF FLORIDA. Will the Subcommittee come back to order, please.

I am pleased to introduce our second panel of witnesses. First, we have Mr. Richard Kuprewicz, who is the Public Member of PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee and President of ACCUFACTS, Inc.

We have Mr. Greg Jones, who is Senior Vice President of the Technical Support Division of Alyeska Pipeline Service Company.

And we have Representative David Guttenberg, who is the House Minority Whip of Alaska State House. He represents House District 8 in the area of Fairbanks, Alaska.

And we have Mr. Adams, Vice President of U.S. Operations, Liquids Pipelines, Enbridge Pipelines.

I want to welcome all of you here today and we are pleased to have you all here this morning. First let me remind each of you that under Committee rules oral statements must be limited to 5 minutes. Your entire statement will appear in the record.

Mr. Kuprewicz, you can start your testimony. Did I pronounce your name right?

Mr. KUPREWICZ. Kuprewicz. But I have been called a lot worse for 40 years. But that is very close, thank you.

Ms. BROWN OF FLORIDA. OK.

STATEMENTS OF RICHARD B. KUPREWICZ, PUBLIC MEMBER, PHMSA'S TECHNICAL HAZARDOUS LIQUID PIPELINE SAFETY STANDARDS COMMITTEE AND PRESIDENT OF ACCUFACTS, INC.; GREG JONES, SENIOR VICE PRESIDENT, TECHNICAL SUPPORT DIVISION, ALYESKA PIPELINE SERVICE CO.; THE HON. DAVID GUTTENBERG, HOUSE DISTRICT 8 - AREA OF FAIRBANKS, ALASKA, ALASKA STATE HOUSE MINORITY WHIP; RICHARD ADAMS, VICE PRESIDENT, U.S. OPERATIONS, LIQUIDS PIPELINES, ENBRIDGE PIPELINES

Mr. KUPREWICZ. I would like to thank the Committee for the opportunity to comment this morning. My name is Richard B. Kuprewicz, and I am President of ACCUFACTS, Incorporated. I have over 37 years experience in the industry, and I have represented numerous parties within the U.S. and internationally concerning sensitive pipeline matters. I am currently a member of the Technical Hazardous Liquid Pipeline Safety Standards Committee representing the public.

My comments today focus on two major pipeline integrity management, or IM, issues and apply to both liquid and gas pipelines. One, changes are needed in reporting IM performance measures. And two, pipeline corrosion regulations are inadequate.

Given the many repairs, more public transparency is required in IM performance data gathering and reporting to assure this method is thorough and, more important, appropriate. This is especially true as more risk-based performance measures are applied by pipeline companies in both high consequence and non-high consequence areas.

The Gulf of Mexico offshore release tragedy clearly underscores what can happen when risk-based performance approaches step into the realm of the reckless and prudent regulation and check and balances don't come into play to prevent such tragedies.

What is missing in the area of IM performance reporting from PHMSA are summaries by type of repair condition; for example, for liquid pipelines immediate repair, 60-day, 180-day, and other; by kind of threat; for example, internal corrosion, external corrosion, third party damage, construction, pipe material, et cetera, actually found at each repair site, by State. Congress should require changes in IM reporting, as I have just summarized, and should also require PHMSA to recompile and restate the anomalies repaired to date, as I believe critically important hindsight will be gained by this effort.

PHMSA is also now taking a more active role in inspecting pipeline construction activities and has discovered very disturbing observations related to some new pipeline—poor manufacturing quality, poor girth welding and other construction-related activities that can seriously effect a pipeline's integrity and IM program over its life cycle.

Congress should assure that PHMSA has sufficient resources to perform these important construction inspections without harming other important efforts. All IM programs obviously should track and report to PHMSA any related new construction, introduced integrity threats, to assure that they have been properly rectified or are under control during the long lifecycle of a pipeline.

In reauthorizing the Federal pipeline safety laws, Congress should also take stronger action on reducing the risk that corrosion poses to the integrity of hazardous liquid and gas transmission pipeline. PHMSA has found wide variation and operators' interpretation of how to meet the requirements of pipeline safety regulations in assessing, evaluating and remediating corrosion anomalies. This raises serious concerns related to how consistent corrosion anomaly evaluations are and stresses the importance of modifying the reporting of IM performance measures as discussed earlier.

It is clear that additional corrosion regulatory standards are required for pipelines both in high consequence areas and non-high consequence areas. For example, mandatory uses of cleaning pigs and avoiding over reliance on corrosion inhibitors that can become ineffective.

Some companies appear to be diluting their corrosion control programs to save money as they overly rely or missrely on IM inspections to catch such risks before failure. It is incumbent upon the pipeline operator to have corrosion and maintenance programs to assure corrosion is under control in all segments of their pipeline and not just rely on IM inspection. Congress should also require that special regulatory focus be directed towards the much higher rate selective corrosion, both internal and external, that can lead to pipeline failure well before the next IM regulatory reassessment, and it is not prudently handled correctly in current regulations.

Given the shortcomings identified in my testimony, it is too early to address the issue of modifying the IM minimum reassessment intervals required by Congress. The matter is especially important for gas pipelines where IM requirements in many areas are less stringent and cover much fewer pipeline miles than that for liquid pipelines.

I would especially advise that Congress pay special attention to gas pipelines, especially those capable of putting more tonnage of hydrocarbon into residential neighborhoods in a form that can cause greater destruction than many liquid pipelines.

Gas transmission pipelines have yet to complete their baseline assessments, have longer reinspection intervals and different special requirements for scheduling remediation reporting than liquid pipelines.

I thank you for your time.

Ms. BROWN OF FLORIDA. Thank you.

Mr. Jones.

Mr. JONES. Chairwoman Brown, Ranking Member Shuster, and Members of the Subcommittee, thank you for the opportunity to appear to discuss the Alyeska Pipeline's Integrity Management Program. I am Greg Jones, Senior Vice President of the Technical Support Division for Alyeska Pipeline. My division includes engineering; health, safety and environmental quality; projects and security.

I have worked for Alyeska for 13 years. Before joining Alyeska, I served for 20 years as an officer in the United States Coast Guard. I am here representing the 1,600 people who operate and maintain the 800-mile Trans-Alaska Pipeline System, transporting crude from Alaska's North Slope to Valdez, where it is shipped to the West Coast.

Safety and integrity of the pipeline are core values at Alyeska and a top priority for every employee. Over the past decade we have continually improved our safety and environmental performance, with 2009 being our best year on record. Although we are proud of our progress, we know that we have to perform well every single day. Regrettably, we did have a significant incident recently, which I will discuss in a moment.

We are here today regarding the integrity management regulations that govern liquid pipelines. We have found the current pipeline safety regulations rigorous, comprehensive and appropriate. Federal regulations require a comprehensive corrosion control program. Alyeska's program is extensive and is monitored by PHMSA.

Our Integrity Management Program is also closely monitored by the Joint Pipeline Office, a unique consortium of 11 Federal and State agencies that provide oversight of TAPS. Our program is subject to inspections by PHMSA. The most recent inspection occurred on August 2009. The inspection team's written exit summary included the following statement: The Alyeska Integrity Management Program document is well organized and addresses the important management system characteristics that are required for a successful program.

Our Integrity Management Program is focused on maintaining the integrity of the pipeline and protecting public safety and the environment. While Alyeska implements and complies with Federal standards, many internal procedures exceed these requirements. We monitor the pipeline through visual inspections, overflights and valve inspections; we conduct internal inspections using smart pigs every 3 years. The regulatory standards require runs every 5 years.

We are required to investigate pipeline segments that could affect high consequence areas when our data tells us there is a wall loss of 50 percent or greater. We actually go by a more rigorous standard of 40 percent. In addition, our corrosion control program includes numerous other elements. A cathodic protection system protects the below ground pipe from external corrosion. Other program elements include our valve maintenance program, river and flood plain maintenance and control. We also have an earthquake preparedness program, a leak detection system, and an over pressure protection system.

Should TAPS experience a pipeline discharge, we have worked diligently to be prepared to respond to an incident. We exercise our personnel and equipment on a regular basis through company and agency-directed drills and under the scrutiny of regulators.

Our spill response preparedness was demonstrated on May 25th, when during a scheduled shutdown of the system a breakout tank overflowed, resulting in a spill to secondary containment that surrounds the tank. There were no injuries and the spill did not escape into the environment. While the response went as required, we clearly find the incident unacceptable. We have done a full investigation into the event and are now working to implement recommendations to ensure that it will not happen again.

As I have outlined, our Integrity Management Program draws on a number of methods that we believe best protect Alaska's environment and keeps the pipeline operating safely and reliably. In Alyeska's 33 years of operations we never experienced a leak on the mainline pipe due to corrosion. We credit the skills and experience of our people, the current regulatory framework, the tools and strategies we use to protect the pipeline, and our aggressive attention to investigation and intervening whenever needed in order to ensure the integrity of TAPS.

I will be happy to answer any questions.

Ms. BROWN OF FLORIDA. Thank you, Mr. Jones. I want to point out that Mr. Jones and Mr. David Guttenberg came all the way from Alaska. So I really, really do appreciate it.

And now the Honorable David Guttenberg, House District 8, Fairbanks, Alaska.

Mr. GUTTENBERG. Thank you, Chairwoman Brown, Ranking Member Shuster, other Members of the Committee and Representative Young, my Congressman. Thank you for the opportunity to speak with you today.

As you said, I am State Representative David Guttenberg and I represent House District 8, which is comprised of the west side of Fairbanks and goes all the way to the community of Cantwell, and the district includes the entire Denali National Park, including Mount McKinley, the highest point on North America.

I spent 25 years of my life working around the pipeline and oil industry. As a young man in 1974, I joined the Labors Union and went pipelining. My first job for Alyeska was with a clearing crew clearing the right-of-way where the pipeline was going to be built. Prior to that I worked on a seismic crew out of Umiat for minimum wage, 14 hours a day at 40 below temperatures, and that is not unusual but here it certainly is.

The next 25 years I worked for various contractors who worked for Alyeska, BP, Exxon and whoever else had a contract with the industry to build whatever was needed to be done. At one point I worked offshore building an island for development and exploration. My last job with Alyeska was in 1996, when we took Pump Station 6 offline.

I am here today on behalf of Alyeska employees that have contacted me with concerns of the safety and integrity of the pipeline, and these concerns they feel have been largely ignored.

My involvement specifically in this began in December of 2009 when I received word that Alyeska was planning to transfer a group of employees from Fairbanks to Anchorage. The proposed transfer raised alarms for me. First of all, for two reasons, they were good jobs and they were leaving my community. Secondly, I couldn't figure out what standard Alyeska used to determine that moving these personnel who were responsible for pipeline safety integrity 350 miles from the pipeline would be prudent and responsible. My initial thought is that it didn't make any sense. When something goes wrong, it needs to be checked on the pipeline. These are the employees who get to the problem, the problem and location quickly. The pipeline goes through Fairbanks; it is 350 miles from Anchorage.

When I began speaking out publicly, several Alyeska employees contacted me and confirmed my concerns. It was explained to me that many in the company shared my sentiment and attempts to express those concerns were squashed at the highest level by senior management who feared retaliation for going against the mandate of Alyeska's then President. At that point it became clear to me that Alyeska's open work environment was not working. Allowing poor decisions to go unchecked could have severe consequences for the State of Alaska.

Alyeska's predicted loss of almost 50 percent of the company's integrity management unit group if the company moved forward with a transfer. This is a long-term negative impact on Alyeska's Integrity Management Program, including deteriorating morale of remaining personnel, a significant loss of expertise and institutional knowledge, and the return to Alyeska's previous history of compliance problems with integrity management issues.

In 1997, under the direction of then Alyeska President Bob Malone, Alyeska transferred employees from Anchorage to Fairbanks to increase pipeline safety and enhance environmental reliability. This was the right move to make and it is difficult to understand how Alyeska's claim of synergy and efficiency justified reversing Malone's decision. Common sense and Alyeska's internal documents suggest that they are making the wrong decision on this one.

Alyeska frequently mentions its recent safety or environmental record when trying to reflect recent criticisms related to the management of its Integrity Management Program; for example, low accident rates. Alyeska's definition of safety refers to the prevention of bodily harm or fatalities to employees or contractors performing work. This safety attribute has little or no bearing on the likelihood of TAPS having a significant spill, which is the issue that brings us here today for this hearing.

For example, a pipeline operator could have an excellent work safety record because there is little or no maintenance being performed on the pipeline, while at the same time it is about to fall apart in 20 locations. The same logic could be applied to Alyeska's environmental record, which can have little or no bearing on the likelihood of a pipeline having a significant spill event.

Finally, I would like to address Alyeska's recent public commentary about emergency spill response capabilities in the first 12 or 24 hours.

Alyeska no doubt continues to have adequate employee and contractor support, but it is not the primary concern related to the transfer integrity manager and personnel. The Trans-Alaskan Pipeline carries an overwhelming majority of Alaskan State revenue and is an integral part of the U.S. Energy infrastructure. With a declining throughput, the line is no less important now than it was 30 years ago. Even through the declining input, the line is no less important now. However, the TAPS infrastructure is rapidly aging and problems are bound to occur. Now is not the time for Alyeska to skimp on pipeline safety and integrity lest we have a significant spill.

Thank you.

Ms. BROWN OF FLORIDA. Thank you.

And Mr. Adams.

Mr. ADAMS. Thank you, Chairwoman Brown, Ranking Member Shuster, Chairman Oberstar, my Congressman, and Members of the Subcommittee. I am Rich Adams of Enbridge Energy Pipeline Company and appreciate the opportunity to participate in this hearing. I am Vice President, U.S. Operations for Enbridge Liquids Pipeline and have more than 20 years of experience working for Enbridge in various engineering, operating, and leadership positions with Enbridge's North America natural gas and liquids petroleum pipeline businesses.

Our liquids pipeline business unit delivers more than 11 percent of overall U.S. oil imports, stretching from Canada into United States refined hubs, delivering about 50 percent of the crude oil refined in the Great Lakes region. More information is included in my written testimony.

The pipeline integrity management regulations respond to societal expectations of safety and build on advances of new technology and pipeline operating experience. The result, a measurable significant reduction infrequency and severity of releases from liquid pipelines. This is a strong indication that Congress' passed mandate of a risk-based integrity safety reg regime is working, and while we are encouraged by this record, our overall goal is zero. Zero releases, zero injuries, zero fatalities, and zero operational interruptions.

To continue this encouraging trend, I urge Congress and the Office of Pipeline Safety to remain focused on a risk-based approach that has delivered this overall performance. The current regulations are extensive and recognize that safety starts with the design stage and continues with a broad range of operating, maintenance, reporting, inspection, and worker qualification requirements.

Reduction of risk considers both the probability of a pipeline failure as well as the potential consequence of such a leak. Congress was on the right track more than a decade ago in focusing regulatory and industry attention on high consequence areas to protect people and the environment. The focus imposed additional protective measures for pipelines at high consequence areas, or HCAs, regardless of whether a pipeline operations in a HCA or non-HCA area, comprehensive Federal regulations still apply to the entire pipeline regarding design, construction, operating, maintenance, and emergency preparedness standards. As such, we cannot agree with those who suggest that non-HCA segments somehow receive little oversight simply because they do not fall under the integrity management plan mandate associated with HCAs.

The whole point of risk management is to aggressively apply our best engineering skills and science to determine the probability and consequence of a potential pipeline failure at any single point along a pipeline.

While only 40 percent of Enbridge's liquids pipeline system could affect an HCA, nearly 100 percent of the mileage has been inspected with internal inspection inline devices. So you might ask why wouldn't the industry just support an expansion of the integrity management rules beyond HCAs. We believe such a mandate would effectively take the industry back to a prescriptive, one-size-fits-all requirement that would abandon the entire science behind risk management, suggesting that the likelihood and consequence of a pipeline incident are essentially the same no matter where they occur.

Collectively, we have been successful at implementing a risk-based approach that directs additional resources to HCAs where a potential release would have the greatest consequence on the public and the environment.

In summary, I think the data shows that Congress, OPS, and industry have been on the right path in the current comprehensive pipeline safety rules and the supplementary Integrity Management Program implementation. When the overall record and trends are taken in context, we have shown noteworthy, continuous improvement in pipeline safety, leading to today's record that is second to none in transportation safety of petroleum.

This concludes my testimony, and I am happy to answer any questions that Members of the Committee may have.

Ms. BROWN OF FLORIDA. Thank you.

The Chairman of Committee the Full Committee has joined us, Mr. Oberstar, and we want to recognize you for any openings statements and we are so happy that you are here.

Mr. OBERSTAR. Thank you. The Committee got disrupted at the beginning with a vote on the floor. I was delayed getting here working on other Committee matters, including our aviation bill. We are hoping to get some progress from the Senate in reaching an agreement on an aviation bill.

Ms. BROWN OF FLORIDA. Well, Mr. Chairman, I just want you to know the whole country appreciates you all moving forward and the Senate moving forward, the other body. We need that aviation bill.

Mr. OBERSTAR. If we can get the Senate to move anything, including time of day, that would be an achievement.

I appreciate you holding these hearings and the participation of Mr. Shuster, but also I was having a conversation, as you turned to me, with Mr. Young, who was Chairman at the time he wrote the most recent pipeline safety bill, but I have been involved with this for at least 25 years, with pipeline safety, from the time that pipeline leaked gasoline in the City of Mounds View just outside my district. A 7-foot long crack in the pipeline leaked gasoline for hours until an automatic shutoff valve finally detected and cut off the flow. But by that time the volatiles had moved up through the soil to the surface, and because those are heavy aromatics they stayed close to the pavement surface. And at 2:00 in the morning a car driving along the street had a loose tailpipe that struck the pavement, the spark ignited the volatiles, the entire street erupted in flame, buckled, melted the pavement, and a mother and her 6-year-old emerged from the house to see what was happening and they were engulfed by flames as they emerged from the front door. Their father-husband took their son and went out the back door and they were the two victims, but houses were burned, the street melted, trees burned. It was a horrific scene. Cause: Corrosion, corrosion that went undetected.

That is what happened with the BP pipeline in 2006, corrosion. It went undetected. We had hearings on that issue in this Committee in 2006. 33,000 barrels it turns out spilled, most of it into a containment vessel but then it spilled over, 5,000 barrels spilled over that containment tank into understandably a contained area, but it was still on the ground and the volatiles just evaporated into the air. They are a hazard to the environment as well. It took three orders from the Office of Pipeline Safety to get BP to take the action they needed to take to correct that problem, and an order, and in fact to DOT's credit at the time, Secretary Mineta, moved the Administrator of PHMSA out, brought in a retired Coast Guard admiral, Admiral Barrett, to take charge of pipeline safety and bring to it the skills of a Coast Guard safety officer, his career had been in safety, and set the Pipeline Safety Administration right.

And then they had to order BP to remove that section of pipeline and replace it altogether. That is something good management should have done on its own; it should not have yaken an order. I have said this in all of the areas of safety under the jurisdiction of this Committee. There has to be a corporate culture of safety; safety starts in the board room. The role of government is to set standards that must be met, but the government doesn't run these corporations. Corporations have to have people in charge whose first concern is safety.

I grew up with understanding safety in an iron ore miners family. My father worked in the Godfrey underground mine. The lives of miners were at risk every day when they were down 300, 600 feet. Now they don't have methane as we have in coal mines, but you have the risk of cave-ins and failures of pilings, of support columns or they are using wood that isn't properly kiln dried and the mine can cave in on people, and there are many other hazards in the underground mines that require a corporate culture of safety. We had the Steelworkers Union that insisted on safety. They didn't have a mine safety and health organization until I was elected to Congress and I authored that legislation to create it.

The same with pipelines. Pipelines, we have nearly 3 million miles in America, they run through communities, in many cases communities built up around the existing pipeline, but that doesn't mitigate the company's responsibility to be vigilant and to take action and to watch over corrosion. That is the enemy of safety. Corrosion is the culprit in most of the pipeline failures.

And then response by organizations—I just want to ask this question, Mr. Kuprewicz, Mr. Jones, Representative Guttenberg, thank you for traveling all the way from Alaska. Mr. Adams, I was at the ceremony for Enbridge in Carlton in my district where I saw more steel pipe in one place than I have seen anywhere in my lifetime. It all looks good now, or then. We want to watch and see what happens to it after it has been buried for a while.

What do you mean by risk management? Mr. Kuprewicz, I will start with you.

Mr. KUPREWICZ. Well, I think it embodies the concept of a corporate culture that knows the difference between speculative risk and risk based on sound engineering principles that don't violate the laws of science. If you assume—like an example would be in corrosion. If regulations have been written, let's say, for general corrosion, the corrosion rate is 12 mills per year, 12 thousandths of an inch per year, and you have selective corrosion like microbiological induced or influenced corrosion and it is 200 mills per year, you are way out of line. And I think there is a lot of science and technology out there that everybody understands and most corporate cultures and risk management understand general corrosion. What we have found in too many instances that resulted in failure there has been a misunderstanding of what I call selective corrosion. And I believe the Minnesota event you described in 1986 was also an example of a selective type corrosion attack. And by selective corrosion it is a different animal. It can really—first of all, it isn't constant over time and it can change. A lot of the regulations and standards are written as if we have general type corrosion. Now I want to be very clear here there are companies who are way ahead of this curve. They understand this science isn't rocket science, it has been around for many decades, and they apply rational risk management, and if they believe they have selective corrosion they are saying I reassess at more frequent intervals. That is a long winded way and I am sorry.

Mr. OBERSTAR. No, it is very important, but the underlying issue is can risk management and in fact doesn't it slip into just a paper management based on historical records, previous experience, and if you have very few incidents then we are going to relax the oversight and relax the requirements. Isn't that an outcome of risk management?

Mr. KUPREWICZ. Well, that can be an outcome, but I would say the more prudent pipeline companies, and they are out there, I want to be very clear about that, this science has been around and developing well for 60 years. They don't drop their guard, they don't make this assumption that it is a paper science. They will look at it and say, looking at our systems, we have different types of risk here. And while we need the paperwork to be sure that we know what we are doing, they don't drop their guard and they will look for signs. Now after enough times you can say I don't have selective corrosion of certain types, for example, but they don't drop their guard, it is a continual evaluation. So I would say the really good companies don't just make it a paper exercise it is an integrated process.

Mr. OBERSTAR. That is the concern I have and that is where we need the constant vigilance on management of risk, and in aviation there was a drift toward this kind of historical experience, will have confidence in if you have had a good record of management instead of the constant reporting and recordkeeping and day-to-day oversight of maintenance.

Mr. Jones, I will give you and Representative Guttenberg and Mr. Adams on it, and then I will stop at this point because other Members have questions.

Mr. JONES. I would look at risk management as a way of looking at the things you have to do, the likelihood of something occurring, of incidents happening and then of course the consequences if they do occur. So you are weighing priorities, and of course a robust integrity management program does exactly that. And we have that at Alyeska. The program—when we run a smart pig, we take a look at and we basically analyze the data and we determine which anomalies need to be investigated first and we follow that sequence in everything. We are also more conservative than the regulations and it has produced very good results.

Mr. OBERSTAR. Does that also include running cleaning pigs in addition to smart pigs?

Mr. JONES. Yes, it does.

Mr. OBERSTAR. That was the problem in 2006, that BP had not run a cleaning pig through that line and had allowed waxes and other corrosive elements to build up within the pipeline.

Mr. JONES. Well, my understanding from reading is that is what happened. For Alyeska we run a cleaning pig every 7 to 14 days, and when we are going to do a smart pig run, we actually run a series of those ahead of the smart pig to make sure that we get good data.

Mr. OBERSTAR. Are those practices what you understand by and include in risk management, periodic, whether you have had a failure or not a periodic run of the cleaning pig through the pipeline and periodic on schedule of running a smart pig through the line; is that included in the risk management?

Mr. JONES. Correct.

Mr. OBERSTAR. OK, Representative Guttenberg.

Mr. GUTTENBERG. Thank you, Congressman. You are always going to have risk management no matter what you do, but my concern is when you take it out of the hands of the qualified engineers that we have on projects like this and put in budgetary concerns for a yearly budget cycle, it might influence something on a budget influence instead of what is the most efficient thing for integrity management and safety. So when we look at those things and are dealing with them in that aspect I think that should probably be—not be part of the review is have the budgetary influence overwhelming the engineering.

Mr. OBERSTAR. When you are operating in what is essentially a hostile environment—I understand that somewhat. We don't have as many months of hostility in northern Minnesota as you do in Alaska, but certainly understand a hostile environment—you need an increased level of vigilance, right?

Mr. GUTTENBERG. Yes, not just certainly for personal safety but for everything that you do, because little things turn into big things very fast, and in Alaska they are in your face all the time.

Mr. OBERSTAR. What was the significance of Alyeska moving personnel from checkpoints along the line out of those areas where they would be available for quick response and consolidating them into Anchorage?

Mr. GUTTENBERG. Well, I think that was the point to begin with why they were moved there in 1997 by then President Malone, is that is where the job is, that is where the response capabilities come from. If you can put somebody there immediately, you might not have a problem. But if you move them 350 miles away, it is going to take a lot longer to do the analysis and to get there and to figure out that if you were there 3 hours ago this would have never happened.

Mr. OBERSTAR. Mr. Adams.

Mr. ADAMS. Congressman, I think certainly when Enbridge and our industry talks about risk management what we are trying to do is we are trying to apply resources where they will have the biggest mitigation of risk. And I think we need to look at our facilities on a case-by-case basis. We have pipelines that have different risks. We have pipelines because perhaps the product that carry or the original installation practices that demand a lot more diligence around corrosion type issues. We have other pipelines that may run through a very populated area that have a very—that transport a very friendly product that have excellent coating, an excellent cathodic protection system that we focus on third-party damage perhaps.

I think even Congress, in applying what they have done in recent years, has looked at pipeline management, integrity management from that risk-based approach. If you look back some years ago, our risks were around third-party damage. That was the number one risk that pipelines had. There has been legislation, there is one called changes that have been enacted that have reduced that and overall risk and all aspects of pipelines have dropped, but certainly in that area it has dropped more than others. We think there are some things that can be done to even enhance that further, but I think all in all that is the attack we need to take to mitigate the risk associated with pipelines.

Mr. OBERSTAR. Thank you, Mr. Chairman. I yield at this point.

Mr. WALZ. [Presiding.] Thank you, Mr. Chairman. Mr. Shuster is recognized.

Mr. SHUSTER. I am going to let myself be passed over for Mr. Young.

Mr. WALZ. Mr. Young is recognized.

Mr. YOUNG. Mr. Jones, how are you picked for the job you have got?

Mr. JONES. I am picked for the job that I have because at Alyeska we have to be competent, we work hard, and we have very professional people, and actually as a leader you surround yourself with good people. That is what I have tried to do and——

Mr. YOUNG. How are you specifically picked, you are now what——

Mr. JONES. You mean to be here today?

Mr. YOUNG. Yes.

Mr. JONES. I am the head of the group that does our Integrity Management Program as the Senior Vice President of Technical Support, and Mr. Hostler asked me to come here.

Mr. YOUNG. Who do you respond to, Mr. Hostler?

Mr. JONES. I respond to Mr. Hostler. He is the CEO.

Mr. YOUNG. And he is picked by whom?

Mr. JONES. He is a BP employee.

Mr. YOUNG. But not for Alyeska?

Mr. JONES. He is picked by the board, the board that basically oversees Alyeska, but he is a BP employee.

Mr. YOUNG. I know, but what I am trying to get across, we set this up specifically so you are not dependent upon the oil companies. When you take that job, if you were to take that job you respond to the Alyeska board and that board is independent of the oil companies.

Mr. JONES. That is correct.

Mr. YOUNG. And that is the way it is set up?

Mr. JONES. That is correct.

Mr. YOUNG. Now in your statement you said you have never had a spill since 1976; is that correct? It wasn't—you know, I admit to two, the one being shot at and the other one the recent one. I think—when was that, that was last—4 months ago, 5 months ago?

Mr. JONES. It was May 25th.

Mr. YOUNG. That at a pump station?

Mr. JONES. Pump Station 9.

Mr. YOUNG. Am I correct it was a breaker, someone hadn't checked the breaker and the pump didn't work or something like that? Physically there was a person there?

Mr. JONES. Yes, there were people there and it was—we did have a failure of a circuit breaker that caused total power loss and that resulted in the relief tank overflowing.

Mr. YOUNG. And the relief tank overflowed into a containment area.

Mr. JONES. That is correct.

Mr. YOUNG. Now this oil that we pumped through that pipeline of 600 and I believe, David, you can tell me, 620,000 barrels a day now or 640,000 barrels?

Mr. JONES. About 640,000 barrels a day.

Mr. YOUNG. Are there any additives added to that oil different than had been added before?

Mr. JONES. No, but what we are experiencing with declining throughput, we are having to deal with changing crude characteristics.

Mr. YOUNG. It is a natural change?

Mr. JONES. Right.

Mr. YOUNG. Now is that more corrosive?

Mr. JONES. It can be, yes.

Mr. YOUNG. And In reality are you running your pigs more often because of that probably added corrosive factor?

Mr. JONES. Yes, we are. In fact we steadily had to reduce the period there that we are running our cleaning pigs because we are experiencing more waxing and everything as throughput comes down.

Mr. YOUNG. You know we have come a long ways though, Mr. Jones, because I can remember the first time Mr. Chairman, Madam Chairman, when I was in this chair actually sitting in this room, I said that we were going to use pigs to go through the pipeline, and someone said, oh, those poor little piggies. Had no knowledge of what we were talking about, but that shows how far we have progressed in this business of pipeline and safety and what we do to find out.

The question, as Mr. Guttenberg has said, the movement of people that was not your decision?

Mr. JONES. The movement of people was a decision supported by the senior leadership team, it was certainly one that Mr. Hostler made but we basically supported as his executive team.

Mr. YOUNG. Now was that a business decision or was that a safety decision?

Mr. JONES. It was a business decision and it did not affect safety.

Mr. YOUNG. Now this is where I question—I happen to like the idea and I don't like to interfere with his private business, but when you say it doesn't affect safety, how do you justify that when the representative said you are 300 miles away. Did you move the pipeline operators from the stations or did you move people out of the Fairbanks region that were in management?

Mr. JONES. We moved people that were in the Fairbanks office. Their duties were principally office based. We still have our full complement of people. There are over 200 people on any given day that are spread throughout the pipeline that are basically——

Mr. YOUNG. Do you have people on site. Let's say the question about 300 miles away, do you have people on site that can respond to the bullet hole?

Mr. JONES. Yes, we do.

Mr. YOUNG. How soon?

Mr. JONES. Well, we have 69 people who are ready basically for immediate response, they are 24/7, you know both shifts, all the time.

Mr. YOUNG. All right. The alarm system goes off because of lack of pressure or increased pressure at one of the stations, goes through the management arena, you have the whole computer board, I have seen it. I am in Fairbanks, how long do it take me to get to pump station let's say—what would it be, Dave, 6, 5?

Mr. GUTTENBERG. Well, 7 or 8.

Mr. YOUNG. How long would it take me to get there?

Mr. JONES. Well, to go to Pump Station 7 you can drive.

Mr. YOUNG. But the one that I can't drive is what I am leading up to.

Mr. JONES. Right.

Mr. YOUNG. Between 1 and 3.

Mr. JONES. Between 1 and 3? Well, we would have the responders that are based out of 4 and we have some people at Pump Station 3, but we have a response base——

Mr. YOUNG. You have people onsite to respond to that.

Mr. JONES. Right. We have them at all active pump stations. They all have personnel and——

Mr. YOUNG. You have them in all active pump stations now?

Mr. JONES. Correct.

Mr. YOUNG. And when you say active, the ones that are not active they have been shut down because of a lack of need of oil or what is that?

Mr. JONES. Well, yeah, as throughput has been coming down we don't need the same pumping capacity. So again for business reasons we take out of service the stations that we don't need.

Mr. YOUNG. And lastly, the Chairman mentioned this, Mr. Oberstar, the illusion of what happened with BP was they were collective lines, weren't they, that had the corrosion in them?

Mr. JONES. Correct.

Mr. YOUNG. And they have been replaced?

Mr. JONES. Right now——

Mr. YOUNG. That has really nothing to do with you does it?

Mr. JONES. That is correct. I was going to say, I don't work with them.

Mr. YOUNG. You don't work with them, that is a different unit?

Mr. JONES. Correct.

Mr. YOUNG. And this is Alyeska and not the collective pipelines?

Mr. JONES. That is correct.

Mr. YOUNG. I am out of time. Thank you, Mr. Chairman.

Mr. WALZ. Thank you, Mr. Young. I said always with the Chairman and with Mr. Young here I feel like I should pay tuition for the lessons and the learning I get. And I want to commend Mr. Young. I think when he talked about his vision of having Alyeska having a separate entity was visionary, was wise in that. I think the point I am trying to get at is since that time of that inception has there been a morphing, a loss of that autonomy? That is what I am trying to get at. I certainly don't want to pile on, I don't want to make the assumption, but I think it is a fair assumption. Alyeska is a for-profit company, correct?

Mr. JONES. That is incorrect. We are not.

Mr. WALZ. It is incorrect. So you make nothing then. The issue is to stay there. So the autonomy issue of having these experts from BP and things is to bring in their expertise but not to necessarily have day-to-day say over the pipeline operation?

Mr. JONES. Well, they are one of five companies that comprise our board, and so they could not dominate the decisions even if they wanted to. We are an independent consortium. We run our company, we have a distinct culture. Our employees are uniquely Alaskan. In fact we are a very diverse company, we hire 20 percent Alaska Natives, the laborers and crafts that work on our pipeline actually choose to want to come work for us due to our safety culture. So we are very distinct. We are proud of all the employees.

Mr. WALZ. I want to get at this point. I think Chairman Oberstar and many others, and yourself, Mr. Jones, with your military history, and I spent about a quarter century as a senior enlisted soldier. There is culture of safety in risk management. It is the air we breathe. I think the Chairman is right, it starts at the top, it starts as a culture. It starts being engrained in every decision that is made. And I just want to ask you, Mr. Jones, if you can see why some people were concerned, the statement that out of the Fairbanks paper November 17th of last year where you indicated—and this move we are talking about, movement of employees, and am I right there were integrity management employees that were part of this move?

Mr. JONES. Yes, sir, there were.

Mr. WALZ. OK. It said all support groups should be looking at Valdez in addition to Fairbanks and asking what the business purpose is for the staff to be based at these locations, Jones wrote. The bias needs to be in favor of them working in Anchorage unless there is a compelling business case to the contrary. Is there not room also for this idea that there is not a mutually exclusive delineation between safety and the smooth running of the company and of the pipeline; why stressing the business case on this as the sole purpose?

Mr. JONES. Well, we were talking specifically about people that are based in offices, we were not talking about our field-based people. And so we had an opportunity to consolidate office buildings there. We were paying for almost 60 percent more space than we were utilizing. And so we—and we had also been involved in a centralization effort back towards Anchorage since 2002. This was just a continuation of that effort.

Mr. WALZ. So the 1997 decision in your opinion was wrong or the situation changed since that time to warrant a review of policy?

Mr. JONES. I would say the 1997 decision was right for that time. Today we are in a different business environment with throughput declining 6 percent every year, so we need to be as efficient as we can.

Mr. WALZ. So this was Alyeska and their board's decision alone. What input, explain to me so we can explain to our constituents, do BP or the other owner companies, what input do they have, sign off, budgeting, things like that, where do they have a role in this?

Mr. JONES. Well, we have an approval authority guide that specifies what levels of authorities and everything that we have as officers of the company and then what things that we have to send to the board for approval. But in this particular case for the office that was an Alyeska decision and it was supported by the senior leadership team.

Mr. WALZ. OK. I want to go to you, Mr. Adams, and ask on this. Where are your integrity management personnel placed? Alaska is big, real big. North Dakota is pretty big, and your pipeline operations. Where are your integrity management people placed? Do you centralize that location?

Mr. ADAMS. There is some centralization. We have many of our integrity management people certainly at higher levels and technical levels actually out of Edmonton, Canada. They provide some overall support. And then strategically based throughout the system within regional areas we do have some integrity management folks. We do have field folks that have responsibility for some parts of integrity management, things such as cathodic protection systems and those sort of things, and they are on the pipe end themselves, via the technician level.

Mr. WALZ. OK, I just have one more before we move to Mr. Shuster. Talking about this May 25th incident, and Mr. Young did a good job of elaborating to us and I think there are some positives in this in containment. One of the questions—and we are seeing this again. I think we would be remiss when one of my colleagues said there is nothing, what is happening with BP in the Gulf, that has relationship to this. I think there is in terms of response and in terms of response plans. I know those best laid plans and I am glad to hear—and one of things, Mr. Jones, you talked about that they gave you flying colors on your document when they looked at it. It is still a document, and I want to know what the indication is on the ground.

My question is the workers that responded to that May 25th incident, do you have a plan for long range watching their health concerns? Is there anything we should be concerned about of vapors, of contact, with was released or anything like that.

Mr. JONES. Well, we do have a plan where we would monitor that, but in this particular case we kept our personnel away from the area until the volatiles were able to essentially flash off. That is one of the things you do in a response, is you look at the hazards and we keep our people out of harm's way.

Mr. WALZ. Will there be a follow-up on those folks to see if there is a cohort of these folks who responded to this thing, if they develop any abnormalities or health conditions?

Mr. JONES. Well, we certainly would, but we were very careful, we did atmospheric monitoring to make sure that we did not put our people in harm's way.

Mr. WALZ. Last thing I would say, Mr. Guttenberg, would you respond on any of these that you maybe have a difference of opinion on these questions that were asked as this applied?

Mr. GUTTENBERG. Well, the placing of personnel is a key part of this equation that is ongoing for me. If you have agency people that need to respond with other agency people, they need to be in proximity to them, but the integrity management people that need to be in the field or in proximity to it that is very important. And I think that is a key to what is a concern for a lot of employees internally. Think there is something wrong, we have a difference of opinion, we are the people that do—they are the people that do the work. And the senior management made a decision that they felt was not in the best interest in the safety and integrity of the pipeline.

Mr. WALZ. You stated, and I will end on this, that there is a culture of folks—I have looked at some these from screen names—I know for protection of integrity, afraid of spill, and some of these folks have written to your and some of the names have come out there. Is there a culture that they fear retribution on this? I know in a military setting that Mr. Jones is familiar with, and everyone else, is that anyone can call a ceasefire, anyone call a safety violation. You can shut down an operation from the lowest private to the general based on that. Do you feel that is not present in this operation?

Mr. GUTTENBERG. Well, I am kind of the cynic when it gets to the top anyway. My history in construction is you sit in a meeting where they say priority is top and the most important thing and you can stop it right now. But when you get to the point when you have to do something, it has to get done. But Alyeska does have a good history, they do have a good dialogue with employees and project employees over the years, but I am not in those offices watching and witnessing what happens.

Mr. WALZ. OK. Well, I thank you all.

Mr. Shuster.

Mr. SHUSTER. Mr. Jones, first of all, I just want to point out based on what the Chairman said and Mr. Walz about your military background, you are a former commander in the Coast Guard, which I think brings great knowledge and that culture of safety to bear on the organization that you work with and work for.

I understand that Alyeska has a major maintenance shutdown, is that accurate?

Mr. JONES. Correct.

Mr. SHUSTER. And how significant is that to the operation, to the safety and to the integrity plan that you have in place?

Mr. JONES. Well, it is very significant. We have been actually doing two major maintenance shutdowns per year where we may do valve work, we may do piping work. And so it is usually major work to where we have to actually be able to isolate a valve or piping from pressure, which is why you do the shutdown, but it is all part of our overall effort for integrity management.

Mr. SHUSTER. As an event is it one of the most significant things you do, those two shutdowns all year?

Mr. JONES. It is a big event and we do tremendous planning to make sure that we can do that safely.

Mr. SHUSTER. When will that occur?

Mr. JONES. The next one will be July 31st.

Mr. SHUSTER. And so I would imagine you have all hands on deck?

Mr. JONES. It is all hands on deck.

Mr. SHUSTER. Everybody is working?

Mr. JONES. From top management right on down. It is a serious thing.

Mr. SHUSTER. I want to point out to the Committee that sometimes in Washington in general there is a disconnect on what goes on in the real world and what goes on in Washington. I would have hoped that we would have taken that into consideration and maybe brought you here after the major maintenance was done, so you probably have spent a number of hours preparing, researching to be before us here today. So when we talk about here in Congress a culture of safety it needs to be start here also in Congress. So again I would hope in the future that the Committee staff and the majority would take those kind of events into consideration because taking you away, being the Senior Vice President for Technical Support, you probably have a lot to do with the maintenance coming up and here you are in Washington when you would better serve the safety culture and the culture of safety back there in Alaska. I just want to make that point.

The question, back to the moving of the staff, I just want to put into the record, ask unanimous consent to put in the Joint Pipeline Office of the Federal-State organization that oversees, has oversight up there in Alaska, put out this letter on—I don't know the date—July 14th and just one paragraph, to read that "We consider Alyeska's transfer of integrity environmental staff from Fairbanks to Anchorage is a business decision because it does not involve first responders."

So I would like the entire letter to be in the record to make sure that we have that because as I think it has been pointed out a number of times this is a business decision, it doesn't effect safety. And with technological changes from computers to monitoring devices to the transportation system, you don't always—in a business model you have got to make decisions to make sure you are efficient. I want to point out when you say nonprofit I think a lot of people think you don't make any money. But a nonprofit has to have more revenue or it should have more revenue than it does expenses or it is going to go down the tubes or you will come to Washington, D.C. And ask for us to bail you out. We need to make sure it is on the record that people know that you have got to be self-sustaining. So you have got to have a positive revenue flow over expenses.

Also, we wanted to ask how does Alyeska spending—how much do you spend annually on your integrity management activities to comply with the Federal pipeline safety laws and regulations?

Mr. JONES. Well, since 2005 coming up to present, we have had a steady increase in the funding for our Integrity Management Program. 2005 expenses were right around $45 million total. And then leading up to today where it will be a little over $60 million.

Mr. SHUSTER. Do you exceed the Federal standards, the Federal requirements, safety requirements?

Mr. JONES. Well, you know, I don't have a breakdown of that, but that is, you know, comprehensively everything that we are putting into the Integrity Management Program. The program is very effective, and, you know, we can see that also in our performance.

Mr. SHUSTER. One final question for you.

Have you ever had a leak on the 800-mile pipeline that was due to corrosion?

Mr. JONES. No, we have not.

Mr. SHUSTER. If I could, I will ask one final question of Mr. Adams.

In your testimony, you claim, in the effort to strive towards the industry goal of zero releases, zero injuries, zero fatalities, no operation interruptions, that Enbridge holds managers accountable for those performance measurements designed to meet those goals during their personal performance evaluations.

If somebody fails to hit those goals, what actions do you take to rectify this?

Mr. ADAMS. Certainly, it depends on the position, but it is incorporated into our overall performance in terms of our bonus structure's pay for employees, and it depends on the level of the organization. Certainly, as you get to higher levels within your organization, there is a bigger impact on that compensation related to safety performance and pipeline integrity performance.

Mr. SHUSTER. I certainly think our goal should be zero fatalities, zero injuries. We certainly want to strive to do that. It is my view, though, that we are going to have human error and the possibility of mechanical breakdowns in striving for that goal as we should do; but I think the only way, realistically, that we can get to that point—and in talking to a company that has a stellar safety record—is you just don't do it. That is the only way we get to zero fatalities. It is the only way we get to zero injuries, unfortunately. I mean would you agree with that?

Mr. ADAMS. Absolutely. I think, traditionally, industry is looked at in terms of safety overall, a pyramid. If you get rid of the small issues, then you can eliminate the big ones in the long term. I think that conventional thinking has changed a little bit as a result of BP and what has happened in our own company with the issues that we have had. What we find is that any breakdown in the management system anywhere along the way—I think Congressman Oberstar mentioned that senior management in the boardroom has to believe in it, but every single one of your leaders within the organization has to believe in it, and when you get a breakdown at any level in that organization, you can have an issue.

I think we, as an industry, and everywhere can get to the point where we can't blame anything on human error because, if our management system works, we have those people trained. We have the right people in the right place doing the right job.

Mr. SHUSTER. Well, I just thank both of you for being here—all four of our witnesses—but these are two great examples of companies that have cultures of safety.

Again, I just want to reiterate that I hope we on the Committee here in the future take under consideration when a pipeline has a major maintenance shutdown, that we bring them to Washington after they have done this major maintenance safety situation that they are going under right now and not drag then down here to Washington to take their eye off the ball on safety.

So thank you very much.

Mr. WALZ. Well, I thank the gentleman.

Also, though, I take my responsibility of oversight seriously. Maybe the gentleman can arrange for us to get to Alaska and make it easier for Mr. Jones and to make sure we are doing our job.

Mr. SHUSTER. I think Mr. Young has made a standing offer, and Mr. Oberstar has, I think, participated many times in that trip up to Alaska to see it firsthand. It should be done by all Members.

Mr. WALZ. We really appreciate it. I think there is little doubt that this entire Committee wants, as I said, to be able to move the petroleum that powers our country, at the same time doing it safely and protecting our workers and the environment.

The one thing I would bring back is this move of employees, though. I want to get at the decisions that were made in this because Alyeska asked its engineering director and the engineering integrity manager, who supervises the Fairbanks employees, to review the risks of moving integrity management personnel to Anchorage, which is exactly what was done.

They generated a report, and the findings—and I quote—stated: There are significant safety and integrity risks associated with movement of the current IM teams to Anchorage.

What overrode those inputs? I would think the engineering integrity manager and the engineering director would be pretty heavyweights in the decision on this. What was the decision then as it was being balanced out, Mr. Jones, to decide to do that?

Mr. JONES. Right. Well, of course, this was not the only consideration, you know, that we looked at.

In the report, they did not have any—we didn't ask them how to mitigate measures or to look at things, and when we went through our analysis, we had lots of discussion. We involved some of those engineers in discussions, and what we came up with was a balance to where we left some people who definitely had more of a role in the field. We left them in Fairbanks—that was three of the engineers—and then the people who had essentially office responsibilities were the ones who we brought in to Anchorage.

I had a conversation with one of the authors of that report just last week, and we talked about this issue. He has assured me, in how we have handled this, that we do not have a safety or integrity problem on the pipeline.

Mr. WALZ. Would that person be willing to state that to us for the record and provide that to me?

Mr. JONES. Well, I can't speak for him, but based on what he told me, I would think he would.

Mr. WALZ. OK. I would like to see if we can follow up on that to get these people who wrote this report. I would like to see if they have changed their position from this, and you are stating that they have. I would like to have them say that, if that is OK.

Mr. JONES. Just to be clear, I am stating that the integrity management manager, who was one of the authors of that report, has told me that.

Mr. WALZ. Very good.

Mr. Shuster hit on this, the $60 million on compliance and safety. Is that a greater percentage of your budget or less in terms of what you put into this? You stated that the number went up, but I think it is important in the context of things. Is maintenance being deferred because it is OK to do that and that the maintenance didn't need to be done at that time or is it being deferred to keep the costs down?

So Mr. Shuster talked about the $60 million. It sounds like a lot, but it depends on how big the pipeline is. It depends on how much needs to be done. It depends on what percentage of the budget that is.

Are you increasing funding on compliance and maintenance in terms of your overall expenditures?

Mr. JONES. We have been on our, what we call, baseline expenses. It has been relatively flat. You would have to look at individual components.

The bottom line is we fund the essential work, and so we prioritize it, and we use that risk-based approach. That was one of the first questions that we had. So we always make sure that we go after the safety and integrity work. That is paramount, and it gets our utmost attention. We also know that if we had to go back for additional funding from the board in order to do that work that we could do so.

Mr. WALZ. The last thing I would ask:

Is there overregulation on pipelines? Is there overregulation? Are we stepping in there? Are we hurting your ability to operate by having too much regulation? I hear this a lot. There is too much government. There is too much regulation. There is too much cost to you or whatever. Is there too much? I will ask each of you, if you can. I know it is subjective, but I would like to hear how you would respond to it.

Mr. KUPREWICZ. Do you just want to go down the line?

Mr. WALZ. Yes.

Mr. KUPREWICZ. No.

Mr. WALZ. OK.

Mr. JONES. What we look for are regulations that provide a very clear target, that are not moving, and that also get consistent application and enforcement of those clear targets. So, to the extent that regulation can do that, then, you know, we will take that on. We are not afraid of strict standards. You know, we understand that, but we need things to be very clear and uniformly enforced.

Mr. WALZ. Are they that way now, in your opinion, Mr. Jones, or not?

Mr. JONES. Well, there are issues. You know, there are definitely things that can be worked on.

Mr. WALZ. OK.

Mr. GUTTENBERG. Thank you.

You know, my legislative career is similar to yours. One of the things, the caveats, that I put in is that it has to work. In some hearings, when people have come in and complained about being overregulated, some of my colleagues from the other side of the table have said, “Give me an example.” “Tell me what the regulation is that is in the way or too cumbersome.” I don’t see the answer, and I sit on the Reg. Review Committee in the legislature, and I haven’t witnessed a lot of it. So, if they have something, they should come forward and be specific about it.

Mr. ADAMS. My comments would mirror, certainly, Mr. Jones’.

I would just add that I think there are some areas—and I mentioned them briefly—where I think we could use some additional regulation, and that is really around third-party damage and in some of the exclusions that exist out there, through municipalities or whatever, and I think that is certainly an area that we would like to see looked at from this body.

Mr. WALZ. Great.

Mr. Shuster, do you have any follow-up? Then we will see if the Chairman has anything.

Mr. SHUSTER. Just on the third party, can you elaborate a little more on that?

Mr. ADAMS. Yes.

What exists out there—there are a number of different One Call-type programs from State to State, and there are certainly some variations.

Mr. SHUSTER. Speak into the mike more.

Mr. ADAMS. Yes.

There are a number of One Call Systems that vary from State to State, certainly, but within those, from municipalities in some cases, there are exemptions given to certain contractors that are actually digging out there that aren’t required to utilize those One Call Systems. From an industry perspective, or at least from an Enbridge perspective, we would like to have those exemptions eliminated.

Mr. SHUSTER. And why are they exempted?

I mean, from a commonsense standpoint, if I am a contractor—well, I just—there was a point a couple months ago when I was digging up trees in my backyard. I made the call because I didn’t want to make the mistake of hitting a gas line and blowing myself up or something like that.

Mr. ADAMS. Yes, I am not sure why those exemptions exist.

Mr. SHUSTER. OK. Thank you.

Mr. WALZ. Chairman Oberstar.

Mr. OBERSTAR. Yes. Thank you, Mr. Chairman.

I thank the witnesses for their responses to the previous questions. I want to come to Representative Guttenberg.

These passages in your statement are very troubling to me, not troubling that you said them, but troubling about the condition of safety, that the move of personnel, which Mr. Jones described as a business decision and you described as a cost-saving measure, the company said would result in a onetime savings of $4 million, but then you go on to say that it would significantly decrease work efficiencies, increase travel costs. It would be the—and you point to an internal review by Alyeska that the loss of almost 50 percent of the company’s integrity management group would occur if the company moved ahead with the transfer and that it would have the effect of deteriorating morale for the remaining personnel and in a loss of expertise and institutional knowledge and would return to Alyeska's previous history of compliance problems with integrity management.

That seems very much to be at odds with what Mr. Jones is saying, trying to sort of brush this over as just a little business decision. This is substantively more than a business decision, right?

Mr. GUTTENBERG. Thank you. That is my feeling as well.

I know the report that Alyeska had done, which was referenced by the Chairman, is where some of that information comes out of. The morale and the loss of employees is—you know, they moved people from Fairbanks to Anchorage. Now they are moving them back. A certain number of them decided not to take that move. I know they were looking for positions at other places. Up until today, it has still been an ongoing situation, but if you are an employee and if you are a highly skilled, trained, educated, experienced engineer, working in integrity management, and you see a situation in front of you that says, "I am not going to be able to do my job if I move to Anchorage, the way it is defined for me in looking at what I need to do," then doing this job is no longer ever going to be satisfactory because I am not going to be able to do it. I am going to have to have more travel time. That is the increased cost. Then you are going to have a loss, and I think the institutional memory cannot be undervalued.

Mr. OBERSTAR. What is the travel time from Anchorage to these outposts along the pipeline where personnel were stationed?

Mr. GUTTENBERG. Well, if you were driving, it would be about 8 hours. If you were flying, it would be an hour plus.

Mr. OBERSTAR. But you wouldn't be driving anyone to respond to an oil spill. You would fly them up there.

Mr. GUTTENBERG. Well, that is not my decision. That is Mr. Jones' decision, but how you get there, whether you go by Glennallen or anywhere in between or any of those small communities or even north, you know, there might not be an airstrip for 20 miles.

Mr. OBERSTAR. That is the other question of mine.

Are there airstrips close to those checkpoints where personnel were located?

Mr. GUTTENBERG. Well, since the construction of the pipeline—and I, you know, was involved in some of that—there are periodic airports and old construction camps all along the pipeline.

Mr. OBERSTAR. Mr. Kuprewicz, you have been involved in pipeline safety for a great deal of your career.

What do you think about the effect of moving personnel with the skills, the expertise, and the institutional knowledge, as Representative Guttenberg stated, and the effect on vigilance and response time and safety in this environment of the pipeline in Alaska?

Mr. KUPREWICZ. Well, first of all, you need to understand the history of Alyeska is they have developed issues that have set some of the original technology because they had serious corrosion risks and problems. They didn't have leaks, but they had corrosion, and those are well publicly known issues.

Mr. OBERSTAR. Yes.

Mr. KUPREWICZ. So they have advanced the field in some of those areas, which are real important, so I don't want to take that away from them.

The other side of it is, as you tend to create chaos in an organization, you have to be real careful with this because there is importance to things likes institutional memory, and that is one of the roles of government—to be sure, I think, that you don't reinvent the wheel. Some of the regulations should set certain minimums, and so you have got to be careful with all of this chaos, if it is real, and I am not up there, so I can't say how this has affected that organization, but you did lose 50 percent of your group.

Now, what was the group, and what were their skills? Those are the kinds of things.

When you create this kind of chaos for a technically cultural-based knowledge skill required, you want to be real careful with that. It doesn't mean you don't have to make those decisions, but you want to be real careful. In some cases, I have seen it in other companies. They have missed that. They have missed that complication with the confusion that they can cause, and they have had to reinvent through various field errors—and some of them not always catastrophic, but they have had to reinvent their learning curve.

So I would just caution folks on that. It is an issue. It is an issue your folks are pursuing. You need to understand that and be comfortable with it. That would be my advice.

Mr. OBERSTAR. Thank you.

Mr. Adams, what is Enbridge's policy on the response and stationing of personnel? This is a very long pipeline that goes from Athabasca in northern Alberta, all the way to the Headwaters of the Great Lakes.

Mr. ADAMS. Yes.

What we have is we have our own emergency response personnel. Effectively, those emergency response groups are spaced probably 3 or 4 hours apart within our pipeline system. So, really, we can get people to the site sooner than that because we have technical-type people that are on call, but the emergency response crew, with equipment and certainly boom and recovery equipment, can be there in a 3- to 4-hour period typically.

Mr. OBERSTAR. Three to 4 hours apart by what measurement?

Mr. ADAMS. By initial reporting, reporting of the leak or the area of the leak. In some instances, that can be a phone call from a third party. It can be our own pilots or aviation observing that there is a leak along the pipeline or an issue. There are a number of different ways we can get notified through our control center.

Mr. OBERSTAR. When the Koch Pipeline burst near Little Falls in Minnesota, it was a person driving by, going home from work, who saw this black geyser shooting into the air alongside Highway 10. He was astute enough to realize that they don't have oil. There are no oil wells there. It is not likely that oil just spurt out of the ground, and he realized it and smelled it.

He called the county sheriff's office, and the sheriff's office then had a phone number for the pipeline company, called "Pipeline Company." Then they called their office in Oklahoma to shut off the valve that controlled that segment of the pipeline.

You know, the time frame was relatively short, but I just wonder what would have happened if that had been the dark of night and no one had seen that going. I asked that question of Koch, and they said, Eventually our sensors would have detected a decrease in pipeline pressure, and eventually that would have caused a shut-off.

Is that what you are talking about? Are those the kinds of automatic valves that are periodically located along the pipeline?

Mr. ADAMS. Yes. We certainly have valves along our pipeline system, and in recent years, we have had programs where we are installing additional valves, automatically operated valves, on each side of the sensitive areas.

Mr. OBERSTAR. But, that 3 to 4 hours, is that response time from the time someone hears or knows of it and is on scene?

Mr. ADAMS. Yes, that would be getting people on scene.

Mr. OBERSTAR. By driving? By flying?

Mr. ADAMS. By driving, typically, in most of our areas.

Mr. OBERSTAR. You measure your response time in hours on the road, driving?

Mr. ADAMS. Yes, a response to have people physically at the site. Certainly, our response time from our control center can be almost instantaneous, and our large leaks are typically detected by our control center personnel. They have enough experience and training that, with usually a leak of any size, they can view that there is a change in the operating system, and there are provisions that, if there is uncertainty, they have to shut down within a period of time, and that would include the closing of automatic valves.

Mr. OBERSTAR. The valve structure that you have on your pipeline and the frequency of valves is that there are more in urban settings and fewer in rural areas. Is that by your standards or are those by the Office of Pipeline and Hazardous Material standards or by State standards or what?

Mr. ADAMS. Yes, there are some standards in place, but we go beyond those standards and set our own standards. We have a risk management group that evaluates our pipeline flows. It evaluates the terrain that the pipeline is going through. Obviously, if you are on flat terrain, if there is a leak that drains up, even if the pipeline is shut down, is relatively small. If you are in a large area where there are large hills, you probably would want to install more valves. You would want to install valves on each side of a river, for example. If, indeed, there were a break in the river, you would close those valves.

So it is very dependent, again, on where the pipelines run and the terrain, and we try to be prudent and, again, looking at where we can minimize the impact if, indeed, we did have a leak.

Mr. OBERSTAR. Now, Mr. Jones, you said in the course of your testimony that there was no effect on people of that spill. Yet the reports that we have are that an employee reported smelling crude, so somebody had to be affected by it. Clearly, somebody was—at least one person, maybe more—and volatiles are carried by wind, and they go considerable distances.

Mr. JONES. Well, that is true that volatiles do travel with the wind. I am not familiar with that particular case.

What I do know is, in responding to that incident, we made safety and the concern about those vapors basically boiling off—you know, since it was a pool in secondary containment, it was important to us to not let our people, you know, get in there, and we waited a considerable amount of time. Then we did atmospheric monitoring, and we made sure that our people were outfitted in the appropriate gear before making site entry. That is a standard part of our response procedures. We actually had a very excellent response in this. It was very timely.

Mr. OBERSTAR. Well, as to the cost-saving measure or business decision you made to bring personnel from the various locations on the pipeline into a consolidated area and to reduce the number of personnel, what is your time frame of moving personnel on scene?

You heard what Representative Guttenberg said. What is your plan? Do you fly them? Do you drive them? Do you use a fixed-wing or a helicopter to get people on site? Have you done a risk management evaluation of time frames and moving personnel on scene in case of failures?

Mr. JONES. We actually do extensive planning to know how long it takes us to respond to certain sites, and we have——

Mr. OBERSTAR. What is that time?

Mr. JONES. Well, it varies depending on where you would have a spill, but we actually get into looking at all of the sensitive areas, and we develop very detailed plans to know exactly what we would need to do for a given scenario.

One thing I need to correct here—and this is where I think there is some confusion—is that the people that we moved from Fairbanks to Anchorage were office-based. They were not part of our initial response team that we have. We have not changed any of our response capability for first responders. We have 69 people, as I said earlier, 24/7 that are ready to go immediately. They are dispersed throughout the stations, along the pipeline and also at the Valdez Marine Terminal. I would rate our response capability as "best in class."

Mr. OBERSTAR. So how many integrity management personnel does that leave on the pipeline on scene at various checkpoints?

Mr. JONES. We don't have integrity management personnel at the pump stations. We never did. These personnel were in the Fairbanks office. There are about 20 total that are in the group. We currently have six vacancies. We have interim measures in place to cover those duties, and we are going through hiring and are actually doing interviewing right now. So I am very confident that we will replace the talent gap that we have, and we will not have safety or integrity impacted.

Mr. OBERSTAR. So your plan is to fill those positions and bring it up to full steam.

Does that satisfy you, Representative Guttenberg?

Mr. GUTTENBERG. We will just have to see, at the end of the day, who is there. You know, where it hits the road is when something happens, and then you discover whether there were competent people in place who could actually do the response, not just the first response, but the secondary response to assess and take action on a spill or a problem.

Mr. OBERSTAR. Now, your constituents in the area of the pipeline where they have seen spills, are they comfortable with these management decisions now?

Mr. GUTTENBERG. You know, Alyeska has been there for a long time. There is a history of taking care of problems. You know, there haven't been any major spills. Spills at Pump Station 9 were contained within the bladder, but there were problems with how that happened as well.

People are concerned, but, you know, we are an oil State at the end of the day, and we look upon that as our flow of revenue, and people are at times really concerned about what would happen if there was a problem. So we are all over the place as far as how we review Alyeska.

Mr. OBERSTAR. I think what this hearing shows us all is vigilance, consistency, a high standard of safety management by the company, a high level of oversight by the Pipeline Safety Management Agency, both Federal and State in a cooperative relationship, particularly in a hazardous environment, all of which were absent in the Gulf.

It is just intolerable that the Minerals Management Service, under the previous administration, exempted BP from filing a blowout failure response plan. None was prepared. None was developed. They are showing today, even today, this very day, that they are still experimenting with containment and protection because they didn't think of it and they weren't required to think of it ahead of time. They were exempted from thinking about how to contain a failure at the wellhead and in the water column.

That failure jeopardizes 50 percent of the fish and shellfish resources of the United States, 300,000 jobs and the future livelihoods of millions of people in the Gulf area, and it stretches all the way up to the Chesapeake Bay where oystermen were counting on oysters from the Gulf off Louisiana to serve their customers here.

I was up on Eagles Nest Lake last week, just after the 4th of July, just on the edge of the boundary waters of the Cuyuna area, with my son and granddaughters, listening to the call of the loons. In 4 months, those loons are going to be migrating to the Gulf, and they are going to meet with a terrible fate if that oil isn't cleaned up, and it won't be cleaned up by that time because that is where they winter. They will be flying right into those marshes where the oil is gathered, and they are going to be Minnesota casualties, Minnesota loon casualties. If those loons don't return next spring, then BP is going to be to blame.

I will leave it at that.

Mr. WALZ. Well, thank you to the Chairman for that summation.

I want to thank each of you on behalf of myself and the Committee for being here, helping us to understand this, helping to be partners in getting this right, as we said, to move a precious resource to fuel our country as well as doing it in a safe manner. It is invaluable.

To Mr. Jones and Mr. Guttenberg, thank you. I don't want to make light of the long travel you made. It truly was.

The hearing will be open for 14 days for Members who wish to make additional statements or to ask further questions. Unless there is further business today, this Subcommittee is adjourned.

[Whereupon, at 12:55 p.m., the Subcommittee was adjourned.]

Congresswoman Laura Richardson

Statement at Committee on Transportation and Infrastructure Committee, Subcommittee on Railroads, Pipelines, and Hazardous Materials

"The Safety of Hazardous Liquid Pipelines (Part 2): Integrity Management"

2167 Rayburn House Office Building

Thursday , July 15, 2010

10:00 AM

Madam Chairwoman, I'd like to thank you for calling this hearing to look at the regulation of our pipelines and what gaps may currently exist. As we have seen in the tragic spill in the gulf, when regulations are not stringent enough and not properly enforces, tragedy can all too easily ensue. While we have had thousands of smaller spills across the country, I applaud your leadership in calling a hearing to examine this issue before a major incident occurs in this area. Chairwoman Brown, all too often an oversight agency waits until the tragedy occurs to act, but through your leadership and this committee we are working to fix this issue before it is too late.

Pipeline safety is a major issue in my district. The 37th Congressional District in California contains 643.15 total pipeline miles in the National Pipeline Mapping System. 558.85 of these miles are hazardous liquid pipelines while the remaining 84.3 miles are gas transmission lines.

The map of pipelines in my district, which I will submit for the record, looks like a spaghetti bowl with pipelines crossing every which way. Not a single one of my constituents can possibly live more than a mile or so away from a pipeline carrying hazardous material, so clearly this issue is critical to the safety of everyone in my district.

Unfortunately, the safety history in my district is far from stellar. From 2000 to 2008 there were 21 incidents in my district significant enough to be reported to PHMSA. And if the national rate of disclosure to PHMSA of only 32% holds in my district, this data could imply that there might have been a total of 66 incidents in just nine years, most unreported.

While thankfully these spills in my district have not cost any lives or injuries, they have caused almost $10 million in damages and spilled over 7,500 barrels, including two spills of over 1000 barrels each.

Likewise, during this time, throughout California, there have been 177 incidents with 9 fatalities costing over $111 million dollars and spilling almost 40,000 barrels. The numbers in California have improved VERY slightly over the past ten years, but not enough has been done. And while my district is disproportionately affected, this is an issue that has impacts across my state and across this country.

My district is densely populated and also sits on the coast with a delicate marine habitat. Clearly we must do something to improve the safety record for the maze of pipelines that cross through my district, and I am thankful that the committee has decided to hold this hearing today to address the issue. I believe that the sheer number of incidents indicates that this industry is in serious need of stricter regulation and must invest in its infrastructure.

I am also concerned that the pipeline industry is mirroring several of the mistakes we have seen in the offshore drilling industry. Government incorporation of industry standards was one of the main issues highlighted in the recent BP oil spill in the Gulf of Mexico with the Minerals Management Service, now known as the Bureau of Ocean Energy Management, Regulation, and Enforcement. The situation isn't any different here where the industry is essentially writing its own regulation.

The Pipeline and Hazardous Material Safety Administration (PHMSA) reported to the Committee after questioning in a 2006 hearing that it has incorporated by reference (in full or in part) 69 separate industry standards into the Pipeline Safety Regulations and 151 separate industry standards into the Hazardous Materials Safety Regulations, including standards from the:

- National Association of Corrosion Engineers
- American Society of Mechanical Engineers
- American Petroleum Institute
- American Society of Testing and Materials
- American Society for Nondestructive Testing
- American National Standards Institute
- International Organization for Standardization
- Det Norske Veritas
- British Standards Institute

Although each rulemaking proceeding goes through notice and public comment, there is no public input into development of the industry standard itself.

Further, an analysis of PHMSA's regulations shows that many of the regulations that "adopt" industry standards do not make such standards applicable to a certain date. For example:

Section 195.444 of title 49, US Code, states: "Each computational pipeline monitoring leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with American Petroleum Institute standard 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system."

Nothing in the regulation stipulates that it is referring to API standard 1130 as of a certain date (i.e. as finalized on a certain date). In essence, the American Petroleum Institute could go in and change the standard and therefore change the regulation, with no public accountability whatsoever.

To make matters worse, the standards are not even printed in PHMSA's regulations or on its website. When looking into this issue, staff could not find API standard 1130. When they contacted PHMSA, PHMSA's response was that the staff had to purchase it from API.

Safety advocates have raised this concern with PHMSA on numerous occasions, including at hearings in the Committee. They have been told that they have to purchase the document from the industry association. That is absurd, and no efforts have been made by PHMSA to make sure these documents are posted on the website.

I'd like to thank the Chairwoman again for calling this timely hearing and thank the witnesses for appearing before us today and I look forward to hearing their statements.

Thank you, Madam. Chairwoman

Testimony of
Richard Adams of Enbridge Energy Company, Inc.

Before the House Committee on Transportation and Infrastructure
Subcommittee on Railroads, Pipelines, and Hazardous Materials

July 15, 2010

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Thank you, Chairwoman Brown, Ranking Member Shuster, and Members of the Subcommittee. I am Rich Adams of Enbridge Energy Company, Inc. and appreciate the opportunity to participate in this hearing.

I am Vice President, U.S. Operations for Enbridge Liquids Pipelines and have over 20 years experience working for Enbridge in various engineering, operating, and leadership positions with Enbridge's natural gas and liquid petroleum pipeline businesses. My experience has included engineering; field operations and engineering; management positions in our joint-venture pipeline in Bogota, Colombia and our U.S. natural gas business unit headquartered in Houston. I recently oversaw Engineering, Procurement and Construction for our recent multi-billion pipeline expansion projects. Enbridge Energy Company, Inc. is the operator of our U.S. gas and liquid pipeline businesses owned by publicly traded Enbridge Energy Partners, L.P., Enbridge Inc., or joint ventures in which we own an interest. Together these various affiliated entities are referred to simply as "Enbridge", except when a legal entity description is required. Enbridge owns and operates a diversified portfolio of crude oil and natural gas transportation systems in the United States and Canada. Its principal crude oil system is the largest transporter of growing oil production from western Canada into refineries throughout the Upper Midwest, accounting for approximately 11 percent of total U.S. oil imports. In fact, Enbridge supplies an estimated 50% of the crude oil refined in the Great Lakes region, and in Minnesota alone, Enbridge supplies nearly 90% of the crude oil refined in the state. In the U.S., Enbridge's natural gas gathering, treating, processing and transmission assets are principally located in the active U.S. Mid-Continent and Gulf Coast area. Enbridge operates over 7,000 miles of crude oil and liquid petroleum gathering and transportation pipelines lines in the U.S. and now has approximately 30 million barrels of crude oil storage and terminaling capacity. Enbridge has 1,934 employees in the United States.

I am pleased to provide some perspectives from Enbridge's experience in our Liquids Pipelines business with implementation of the Integrity Management regulations that have been in place for approximately a decade. I appreciate that this hearing is one of a series the Committee has held or planned, so I will attempt to build on what I understand has been presented previously.

<u>The Integrity Management Rules Are Built Upon Decades of Pipeline Safety Regulation</u>

The Department of Transportation, Pipeline and Hazardous Materials Safety Administration's (PHMSA) Office of Pipeline Safety (OPS) has developed comprehensive rules over many decades. These regulations have been improved and expanded over this timeframe, building on new technology, experience, societal expectations for high performance and in some cases lessons-learned from accidents. The effectiveness of these extensive regulations along with industry-driven initiatives to raise the safety-bar for petroleum pipelines led to a reduction in the frequency of releases from liquid pipelines. Specifically, according to the industry's pipeline performance tracking system, the frequency of liquid petroleum pipeline spills decreased from 2 incidents per thousand miles in 1999-2001 to 0.7 incidents per thousand miles in 2006-2008, a decline of 63 percent. Similarly, the number of barrels released per 1,000 miles decreased from 629 in 1999-2001 to 330 in 2006-2008, a decline of 48 percent. Enbridge's pipeline safety record has also similarly improved over this timeframe. The industry is proud of this record, but continues to strive for zero releases, zero injuries, zero fatalities and no operational interruptions. Enbridge shares this laudable goal and we've established our own corporate social responsibility and reporting, and operating performance goals – objectives that all managers are held to each year in their personal performance evaluations.

Enbridge has focused a great deal of resources in pipeline and systems integrity, including but not limited to corrosion control, detection of material defects so they can be repaired prior to leaking, technology improvement and worker qualification. And despite significant progress over the last twenty years, Enbridge supports, along with many other initiatives, continued efforts to reduce the risk of 3rd party excavation damage. The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act) took an important step forward by creating incentives for states to adopt improved damage prevention programs. It did not, however, go far enough. One of the largest risks still existing in some state's damage prevention programs is the exclusion of certain excavators from the notification requirements of state "one-call" systems. These groups often include municipalities, state highway departments, and railroads. In order to provide maximum protection to the public, exemptions from state "one-call" requirements should be eliminated.

Third-party damage is only one area of focus in Enbridge and the pipeline industry's safety practices and OPS's liquid pipeline safety regulations. The breadth of these regulations begin at the design stage – such as material specifications and construction codes – and include a broad range of operating, maintenance, reporting, inspection and worker qualification requirements. These mandates focus on practices shown over time to reduce the risk of corrosion, material defect, worker error and excavation damage or other threats to pipeline safety. Since the 1960's when our modern-day federal regulatory regime began, the focus of the OPS has been on implementing or expanding mandates that strive to reduce both the probability of pipeline failures as well as decrease the consequences of a pipeline leak.

As societal expectations increasingly focused on the value of protecting both the environment **and** public safety, the federal pipeline safety regulations have evolved. OPS's and industry's environmental protection priority was particularly heightened after Congress passed the Pipeline Safety Reauthorization Act of 1996.

Enactment of the Liquid Pipeline Integrity Management Rules

It is within this backdrop that today's comprehensive federal pipeline safety standards evolved. In the years leading up to enactment of the Integrity Management Plan rules, the industry and OPS had been working toward a more risk-oriented approach to rulemaking. This approach was first tested by creation of an Interim Risk Management Consensus Standard, developed with involvement of OPS technical representatives. Very soon, however, OPS began the effort to implement the current Integrity Management Plan rules, after working with all stakeholders and the Technical Hazardous Liquids Pipeline Safety Committee to define those areas along pipeline routes that were of the highest priority. As ordered by Congress in the early 1990's, "High Consequence Areas" ("HCAs") were defined for hazardous liquid pipelines as (1) highly populated areas, (2) commercially navigable waterways, and (3) unusually environmentally sensitive areas. While the comprehensive federal regulations already mandated design, construction, operating, maintenance and emergency preparedness standards for all pipeline segments, these categories of HCAs were deemed of high enough value to warrant additional preventative and mitigative actions.

This is an important point to reinforce. Specifically, there have been characterizations by some that imply that non-HCA segments somehow receive little oversight simply because they do not fall under Integrity Management Plan mandates. It is Enbridge's view that this perspective misses the whole premise of risk-management, whereupon the pipeline system continues to be maintained to a federally mandated baseline regime and a wide array of technical standards developed under ANSI stakeholder involvement and development guidelines. Therefore in High Consequence Areas additional resources are placed over and above this baseline to even further reduce the risk in especially sensitive areas where our tolerance for impact is even lower than elsewhere.

Currently, according to the PHMSA website, 44 percent of liquid petroleum pipeline mileage could affect an HCA justifying this additional layer of oversight and preventative measures. Non-HCA pipeline segments are still subject to the comprehensive rules in 49 CFR Part 195. Moreover, operators of liquid pipelines must also comply with the comprehensive spill prevention and response planning requirements for jurisdictional pipelines found in 49 CFR Part 194 and Parts 190 and 199 apply to enforcement and drug and alcohol testing, regardless of whether the pipeline is in a HCA.

Enbridge Experience with the Liquid Pipeline Integrity Management Plan Rules

Enbridge management participated in the development of consensus technical standards and the current Integrity Management Rules. In the U.S., Enbridge operates 7,800 miles of onshore liquid pipeline subject to 49 CFR Parts 194 and 195, of which approximately 40% are in locations that could affect an HCA.

Enbridge completed the baseline integrity assessments of all the HCA segments by the 2008 deadline and we have updated our analysis to show new or revised HCA's along the system or reflect new pipelines built in recent years. We are now in the process of completing re-assessments within the prescribed timelines. Baseline IMP assessments are an effective means of identifying any material or construction defect as well as corrosion. In-line inspection devices, or "smart pigs", are the predominate means for performing integrity assessments within the Enbridge Liquids Pipeline system because the mainline pipe was designed to accommodate the devices and they are the most versatile and efficient devices for the required integrity assessment inspection process. In fact, Enbridge had been using increasingly sophisticated internal inspection devices in our liquid system integrity program for more than a decade prior to the Integrity Management rules. The other methods of integrity assessment baseline testing – such as hydrostatic pressure tests and direct assessments, while appropriate when smart pigs cannot be used, often require significant interruptions in pipeline service.

While only 40% of our system could affect an HCA, nearly 100% of the mileage has been inspected (often a number of times) with internal inspection devices. This is consistent with OPS information on their website that more miles of liquid pipeline have been internally inspected than required by federal rules, as most liquid pipelines can accommodate internal inspection devices and the nature of device requires movement through many miles between internal inspection device launching and receiving traps – passing along both HCA and non-HCA mileage.

The natural question is why wouldn't the industry just support an expansion of the Integrity Management Rules beyond HCA's? It is important to emphasize that the Integrity Management Plan rules are far more than simply an inspection mandate. Simply put, pipeline operators must identify, prioritize, assess, evaluate, repair and validate—through comprehensive analyses—the integrity of hazardous liquid pipelines that, in the event of a leak or failure, could affect High Consequence Areas (HCAs) within the United States. There are repair deadlines based on technical codes for repairs in non-HCA's. The cornerstone of the Integrity Management Rule is a risk and threat assessment, and OPS inspectors have spent many days reviewing Enbridge's analysis of potential threats of hazards in HCA's and our rationale for reducing the potential for such incidents. Going back to a prescriptive "one-size-fits-all" mandate treating all areas along the pipeline and all hazards as equal misses the premise of risk-management that considers both the likelihood <u>and</u> consequences of an incident.

High Consequence Areas by definition will evolve over time as Enbridge has already supplemented updates to originally defined HCA's along our system, along with a corresponding update in our Integrity Management Plans. The update in HCA's complies with OPS regulations requiring reassessment of pipeline systems for the presence of new HCA's, such as growing population centers, new sole source drinking water resources or state-identified species designations. We believe Congress and OPS were correct to implement a risk-based system to manage the integrity of our nation's energy pipelines. Such a system supplements the baseline pipeline safety protection practices by directing additional resources where a potential release would have the greatest consequence on the public and the environment. Enbridge shares the pipeline industry's concerns with simply mandating Integrity Management requirements on every pipeline segment in the country.

Enbridge has invested considerable resources toward assessing, maintaining and growing our liquid pipeline energy delivery infrastructure. Our customers and the public demand reliable energy supply and our investors expect that we manage risks to their investment in our company. Therefore, in addition to a value held by Enbridge, we know that communities, customers, regulators, investors and Congress all hold us to high standards for reliable, economic and safe deliver of liquid petroleum.

<u>Conclusion</u>

In summary, Enbridge operates one of the nation's largest volume liquid pipeline systems delivering more than 11% of U.S. import crude oil supply. Safety and protection of the public and environment are our highest priorities, indeed I think it is a fair reading of our publications and actions that we hold this as a core value – not just a priority. In addition, as a critical supply of crude oil to refineries in America's heartland, we take our responsibility for customer and consumer supply reliability just as seriously. We believe the liquid Integrity Management Plan rules have only recently been fully implemented and need time for OPS and industry to evaluate for effectiveness. Significant resources have been spent in compliance with the Integrity Management Rules. However, these supplementary safety resources are well-spent for protecting our nation's more important high-consequence areas. Meanwhile, Enbridge – and the pipeline industry as a whole – continues to adhere to the current comprehensive federal regulations that serve as an extensive pipeline safety baseline for the entire pipeline system. The industry's record has shown noteworthy continuous improvement over recent decades and is second to none in transportation safety of petroleum.

This concludes my testimony and I am happy to answer any questions that members of the committee may have.

Testimony of Representative David Guttenberg
Alaska Legislature
Before the
Subcommittee on Railroads, Pipelines, and Hazardous Materials
Committee on Transportation and Infrastructure
United States House of Representatives
Hearing on
The Safety of Hazardous Liquid Pipelines (Part 2): Integrity Management
Washington, DC
July 15, 2010

Chairwoman Brown, Ranking Member Shuster, Members of the Subcommittee, thank you for the opportunity to speak with you today. I am State Representative David Guttenberg and I represent House District 8 in the Alaska Legislature. House District 8 is comprised of the west side of Fairbanks, sometimes called the university district, but my district also extends 150 miles south down the Parks Highway to the community of Cantwell. Included in the district is the entire Denali National Park and North America's tallest peak, Mt. McKinley.

I have spent 30 years of my life working in and around the oil industry. As a young man in 1974 I joined the Laborers Union and went to work "pipelining." My first job with Alyeska was clearing the right of way where the pipeline was going to be built. Prior to that, I had a job working on a seismic crew out of Umiat for minimum wage, 14-hour days at 40 below temperatures. For the next 25 years I worked for contractors working for Alyeska, BP, and ARCO building pipelines, pump stations and any other facility that was needed. In 1981 I worked off shore in Prudhoe Bay building an island for exploration and development. My last job with Alyeska was in 1996 when we took Pump Station 6 offline.

I am here today speaking on behalf of the Alyeska employees who have a deep concern for the safety and integrity of the pipeline, but whose concerns have been largely ignored.

My involvement in this issue began in December 2009 when I received word that Alyeska was planning to transfer a group of employees from Fairbanks to Anchorage. I was told that the engineers, technicians and scientists proposed for transfer are critical to monitoring and maintaining the integrity, public safety and environmental compliance of the Trans-Alaska Pipeline System (TAPS).

The proposed transfer raised alarm bells with me for two reasons: First, those were good jobs moving out of my community. Second, what standard did Alyeska use to determine that moving personnel responsible for the pipeline safety and integrity 350 miles away from the pipeline would be prudent and responsible? My initial thought was that it makes sense for these positions to be located in Fairbanks because it is a transportation-hub centrally located on the pipeline right-of-way. When something goes wrong or needs to be checked out on the pipeline, these employees can get to the problem location quickly. Anchorage is nowhere near the pipeline. In just about every scenario, it is quicker for these employees to reach the pipeline from Fairbanks.

When I began speaking out publicly, several Alyeska employees contacted me and confirmed my concerns. It was explained to me that many in the company shared my sentiment, but attempts to express those concerns were squashed at the highest levels by senior managers who feared retaliation for going against the mandate of Alyeska's president. At that point it became clear to me that Alyeska's "open-working-environment" was not working at all, allowing poor decisions to go unchecked that could have severe consequences for the state of Alaska.

Publicly, Alyeska touted the move as a cost-saving measure that would increase work efficiencies and synergies. However, this contradicts an exhaustive internal review of the transfer, which clearly demonstrates from both quantitative and qualitative evaluations that an Anchorage location would significantly decrease work efficiencies and increase travel costs for Integrity Management personnel - to the tune of about $250,000 per year. The increased travel costs are significant because the savings claimed by Alyeska is a single ***one-time*** amount of $4 million in today's dollars. Furthermore, a significant portion of these savings could have been achieved without the transfer as Alyeska's Fairbanks office space was being underutilized (less than 50% occupancy level) and could have easily been consolidated while leaving room for pre-transfer personnel. Essentially, Alyeska incorrectly associated the employee transfer with these savings.

Alyeska's internal review also accurately predicted the loss of almost 50 percent of the company's integrity management group if the company moved forward with the transfer. This will have a long-term negative impact on the Alyeska Integrity Management Program, including deteriorating morale of remaining personnel, a significant loss of expertise and institutional knowledge, and a return to Alyeska's previous history of compliance problems with integrity management regulations.

In 1997, under the direction of then-Alyeska President Bob Malone, Alyeska transferred employees from Anchorage to Fairbanks to increase pipeline safety and enhance environmental reliability. This was the right move to make and it is difficult to understand how Alyeska's vague claims of synergy and efficiency justify reversing Malone's decision. Common sense and Alyeska's own internal documents suggest Alyeska is making the wrong call on this one.

Now I would like to say a few words about safety. Alyeska frequently mentions its recent"safety" (or environmental) record when trying to deflect recent criticisms related to the management of its Integrity Management program, for example, low worker accident rate, API Distinguished Operator Award, etc. Alyeska's definition of "safety" refers to the prevention of bodily harm or fatalities to employees or contractors performing work activities for TAPS. This "safety" attribute has little or no bearing on the likelihood of TAPS to have a significant spill event, which is the issue of concern that brings us to this hearing today. For example, a pipeline operator could have an excellent worker safety record because there is little or no maintenance work being performed on the pipeline while at the same time it is about to fall apart in 20 locations. The same logic can be applied to Alyeska's environmental record, which can have little or no bearing on the likelihood of the pipeline to have a significant spill event.

Finally, I would like to address Alyeska's recent public commentary about emergency spill response capability in the first 12 to 24 hours where spill containment and mitigation of direct impacts to the environment are most important. Alyeska no doubt continues to have adequate employee and contractor support to address this issue, but that is not the primary concern related to the transfer of Integrity Management personnel to Anchorage. The real concern is a significant reduction in the ability of IM personnel to quickly respond to and assess emergency situations along the TAPS right-of-way, not in a spill containment or "first responder" capacity, but in a capacity to assess emergency situations and determine safe and feasible options for maintaining pipeline operations or re-starting the pipeline after an incident. An example of this is the 2002 Denali Fault 7.9-magnitude earthquake (located 2 hours from Fairbanks) when Alyeska's Integrity Management engineers were able to quickly drive to and inspect the pipeline for damage and determine if the pipeline could be safely restarted.

The Trans-Alaska Pipeline System carries the overwhelming majority of Alaska's state revenue and is an integral part of the U.S. energy infrastructure. Even with declining throughput, the line is no less important now than it was 30 years ago. However, the TAPS infrastructure is rapidly aging and problems are bound to occur. Now is not the time for Alyeska to skimp on pipeline safety and integrity lest we have a significant spill event comparable to the Exxon Valdez spill or the recent Deep Water Horizon rupture.

Statement of Greg Jones
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before the
Subcommittee on Railroads, Pipelines and Hazardous Materials
Committee on Transportation and Infrastructure
United States House of Representatives

regarding
The Safety of Hazardous Liquid Pipelines (Part 2):
Integrity Management

July 15, 2010

Statement of
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July 15, 2010

Chairwoman Brown, Ranking Member Shuster, and Members of the Subcommittee, thank you for the opportunity to appear here today to discuss Alyeska Pipeline Service Company's integrity management program. I am Greg Jones, Senior Vice President of the Technical Support Division for Alyeska Pipeline Service Company. My division includes Engineering; Health, Safety and Environmental Quality; Projects & Project Controls; and Security. I have worked for Alyeska for thirteen years. Before joining Alyeska, I served for twenty years as an officer in the U.S. Coast Guard.

I am here representing the 1600 people who operate and maintain the 800-mile Trans-Alaska Pipeline System, or TAPS, transporting crude oil from Alaska's North Slope to Valdez, where it is shipped to the West Coast in the Lower 48 states. Today, TAPS carries about 14 percent of the nation's domestic oil production. Since startup in June 1977, we have transported more than 16 billion barrels of crude oil. At peak production, we transported 2.1 million barrels per day. However, production from existing development on the North Slope has been declining by approximately 6 percent per year, so we currently transport approximately 650,000 barrels per day on average.

Safety and integrity of the pipeline are core values at Alyeska, and a top priority for every employee. Over the past decade we have continually improved our safety and environmental performance, with 2009 being our best year on record. We recently celebrated one year and more than five (5) million working hours without any days away from work due to an injury. We have been awarded the API Pipeline Environmental Performance Award six times in the last decade, and received the Distinguished Operator Award for 2008. Although we are proud of our progress, we know that we have to perform well every single day. Regrettably, we did have a significant incident recently, which I will discuss in a moment.

Integrity Management Program

We are here today regarding the integrity management regulations that govern liquid pipelines. We have found the current pipeline safety regulations rigorous, comprehensive and appropriate. Federal regulations require Alyeska to have a comprehensive corrosion control program. Alyeska's corrosion control program is extensive, and is based upon the federal Department of Transportation Pipeline and Hazardous Materials Safety Administration, or PHMSA. Our integrity management program is also closely monitored by the Joint Pipeline Office. The JPO is a unique consortium of 11 federal and state agencies that provides oversight of TAPS. Annually we provide the JPO with a corrosion assessment and also six additional reports on pipeline integrity. These are representative of the amount of oversight on TAPS.

We operate our integrity management program through a comprehensive documented plan and through written program procedures. The plan provides for baseline and continuous re-assessment of our pipeline using inline inspection, a review of integrity assessment results, risk assessments, preventive and mitigation measures, a continual process for data integration, and the development and review of program performance metrics. Any shortfalls in this area are dealt with promptly.

Our comprehensive Integrity Management Program is subject to inspections by PHMSA as part of our regulatory program, which most recently occurred in August 2009. The inspection team's written exit summary included the following statement:

> The Alyeska Integrity Management Program document (IM-244) is well organized and addresses the important

management system characteristics . . . that are required for a successful program.

Alyeska's extensive integrity management program is focused on maintaining the integrity of the pipeline and protecting public safety and the environment. This program takes a system-wide approach, using activities designed to monitor and maintain the integrity of all facilities on TAPS. While Alyeska implements and complies with the safety standards set by the federal Office of Pipeline Safety, we also have internal procedures that exceed these requirements in many respects. I will share examples shortly.

An operating pipeline is monitored in a variety of ways. Alyeska's employees routinely visually inspect the pipeline and right-of-way. We conduct overflights along the pipeline Right of Way at least once weekly, and often more frequently, looking for signs of unusual activity or any environmental changes that might indicate a developing issue. We inspect valves and maintain our pump stations. We conduct internal inspections using special detection equipment known as "smart pigs" to monitor the pipeline for corrosion. These devices can take readings of the pipeline and provide data that alerts us if the pipe has moved, or if its wall thickness has changed.

We run these smart pigs through the line every three (3) years. This is an example where we exceed regulatory standards, which require pig runs every five (5) years. We analyze the pig run data and from this, our engineers make recommendations about what sections of the pipeline should be physically looked at for additional validation and any required repair. By using the data to decide what integrity investigations need to occur, we're ensuring that the parts of TAPS that need the most attention receive it. We investigate sections of the pipeline, above and below ground, to determine the significance of anomalies, including corrosion. Based upon this assessment, the appropriate corrective actions are taken.

We are required to investigate pipeline segments that could affect High Consequence Areas when our data tells us there is a wall loss of 50 percent or greater. We actually go by a more rigorous investigation standard, and will investigate when we detect a wall loss of 40 percent.

We also run cleaning pigs through the entire length of the pipeline every seven to fourteen days. These pigs are designed to push wax, water and sediment down the line for removal. As our throughput has declined, and fluid temperature has also declined, cleaning pigs have become an even more important integrity tool for us, as they remove wax that may drop out of the crude oil at a reduced velocity.

In addition to pigging and integrity investigations, our corrosion control program includes numerous other elements.
A cathodic protection system passively and actively protects the below ground pipe from external corrosion. The passive system uses sacrificial galvanic (zinc and magnesium) anodes which preferentially corrode, thus protecting the pipeline from corrosion (similar to the zinc anodes in home water tanks). The active system applies electrical current to the pipeline to prevent corrosion. A total of approximately 1,700 cathodic protection test stations are placed along the pipeline to provide a way to measure the effectiveness of the cathodic protection system. Cathodic protection monitoring, including annual test station readings and close interval surveys, are performed on one-third of the pipeline each year. Areas not meeting the cathodic protection criteria are either mitigated or electrically adjusted.

We conduct a similar inspection program for the breakout tanks that are located at the pump stations. These tanks are inspected for corrosion, both visually and by using technology such as ultrasound. These tanks also have cathodic protection for the underside of the tank bottoms.

Other program elements include our valve maintenance program; river and floodplain maintenance and control; and regular integrity investigations and repairs on our 150-mile fuel gas line, which delivers fuel gas from the North Slope producers to Pump Stations 1, 3, and 4. We also have a comprehensive earthquake preparedness program, a leak detection system, and an overpressure protection system. All of these systems are reviewed and approved by the Joint Pipeline Office or associated agencies, such as PHMSA or the Alaska Department of Environmental Conservation.

We continue to improve our systems. Beginning in 2008, we initiated substantial capital improvement projects to increase our cathodic protection levels, including:

- the installation of new impressed current anode beds at various locations line wide,
- the installation of deep well anodes, upgrading existing electric generators and rectifiers line wide,
- removal of electrically-shorted casings at various road crossings,
- installation of a line-wide remote monitoring and control system for cathodic protection rectifiers, and,
- addition of cathodic protection test stations on the fuel gas line between Pump Station 1 and Pump Station 4.

This work will be completed in 2011. We have plans to continue capital improvement projects in the coming years.

I want to stress that our program is primarily focused on prevention, protecting public safety, caring for the environment and business continuity.

Should TAPS experience a pipeline discharge, we have worked diligently to be prepared to respond to an incident. We have an approved oil discharge prevention and contingency plan that guides our response efforts. The plan is reviewed and approved by four regulatory agencies: the Alaska Department of Environmental Conservation, the U.S. Environmental Protection Agency, the U.S. Department of Transportation, and the U.S. Bureau of Land Management. We exercise our personnel and equipment on a regular basis through company and agency-directed drills, and under the scrutiny of regulators. While it is our goal to avoid an oil discharge, we are prepared for an incident and can respond effectively and in a timely manner.

Our spill response preparedness was demonstrated on May 25th of this year, when, during a scheduled shutdown of the system, a breakout tank overflowed, resulting in a spill to the secondary containment that surrounds the tank. There were no injuries and the spill did not escape into the environment, but approximately 4,500 barrels of crude oil were captured within the secondary containment system. Sixty-nine (69) trained oil spill response personnel responded to the site, and a 30-member incident management team was activated. Many others in the Company added their expertise. Our contingency plan was followed, and as a result, there were no injuries and there was no damage to the environment. While the response went as required, we clearly find the incident unacceptable. We have done a full investigation into the event, and are now working to implement both system and process recommendations to ensure that it will not happen again.

As I've outlined, our Integrity Management Program is a comprehensive system that draws on a number of methods that we believe best protect Alaska's environment and keep the pipeline operating safely and reliably. In Alyeska's 33 years of operations, we've never experienced a leak on the mainline pipe due to corrosion. We credit the skills and experience of our people, the current regulatory framework, the various tools and strategies we use to protect the pipeline, and our aggressive attention to investigation and intervening whenever needed in order to ensure the integrity of TAPS. We're proud of our integrity management program that we use to safely operate and maintain the Trans Alaska Pipeline System.

I'll be happy to answer any questions.

Accufacts Inc.
"Clear Knowledge in the Over Information Age"

Testimony of
Richard B. Kuprewicz, President

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BEFORE THE

COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
SUBCOMMITTEE ON RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS
U.S. HOUSE OF REPRESENTATIVES

HEARING ON

THE SAFETY OF HAZARDOUS LIQUID PIPELINES (PART 2): INTEGRITY MANAGEMENT

JULY 15, 2010

I would like to thank the Committee for the opportunity to comment this morning. My name is Richard B. Kuprewicz, and I am president of Accufacts Inc, but I am here today as a representative of the public. I have over 37 years experience in the energy industry and I have represented numerous parties, within the U.S and internationally, concerning sensitive pipeline matters.

The vast majority of our clients are public citizens, representatives of local city, county, state, or federal governmental agencies, nongovernment organizations, as well as industry, who need highly specialized independent neutral expertise in these critical matters. To cite two specific examples from our extensive client base: Accufacts played a key role for the City of Bellingham, Washington in developing and negotiating both the Bellingham Pipeline Safety Immediate Action Plan and a Long Term Franchise Agreement with Olympic Pipeline defining startup as well as operational, design, and pipeline management process modifications following the 1999 liquid pipeline tragedy. Accufacts also assisted the Lower Colorado River Authority (LCRA) in Austin, Texas in their successful negotiations and efforts with the Department of Justice, Department of Transportation, Environmental Protection Agency, and Longhorn Pipeline Partners LLP obtaining critical design and operational safety enhancements for the 18-inch liquid products Longhorn Pipeline project.

I currently serve as a representative of the public on the Technical Hazardous Liquid Pipeline Safety Standards Committee and have also served as a representative of the public on various PHMSA/OPS working committees related to pipeline control room management efforts, and as an Executive Member and subcommittee member on the committees assisting PHMSA on the Distribution Integrity Management Program ("DIMP") Report development for Congress, and DIMP federal pipeline safety final rulemaking. Congress identified these important pipeline matters in the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES 2006). I also served for approximately seven years on the Washington State Citizens Committee on Pipeline Safety as a public representative, also serving a stint as its chairman. This Governorappointed pipeline safety Advisory Committee is the only one of its kind in the nation and was formed after the Bellingham tragedy.

I was invited today to provide brief comments based on my experiences related to pipeline Integrity Management ("IM"). While my primary focus today will be on liquid transmission pipelines, many of these comments also apply to gas transmission pipelines. My comments today focus on two major IM issues:

- **Changes are needed in reporting IM performance measures**
- **Pipeline corrosion regulations are inadequate**

Changes are needed in reporting IM performance measures

As a result of the Bellingham, Washington liquid pipeline and the Carlsbad, New Mexico gas transmission pipeline ruptures, as well as other pipeline failures, Congress required integrity management for both liquid and gas transmission pipelines affecting High Consequence Areas (HCAs) in an attempt to ensure that pipeline operators had control of their pipeline systems to prudently avoid such terrible tragedies. Before integrity management, with the exception of an initial hydrotest following pipeline construction, pipeline operators were not required to assess or periodically inspect to ensure their pipelines were under the operator's control to avoid failure. Today 44% of approximately 173,000 miles of hazardous liquid pipelines in the U.S., or 76,000 liquid pipeline miles, and approximately 7% of roughly 300,000 miles of natural gas transmission system, or 21,000 gas transmission pipeline miles, fall under the HCA designations captured by minimum federal IM pipeline safety regulations. Under liquid pipeline IM regulation, pipeline segments that could affect HCAs were to complete initial baseline inspections by February 17, 2009. Following these baseline assessments, reassessment intervals are set at five years for liquid pipelines. Thus, liquid pipelines have completed their initial baseline assessments and are now into their first regulated reassessment cycle.

To date, PHMSA's latest website, summarizing liquid pipeline IM repairs from the 2001 through 2008 time period, indicates that approximately 32,000 pipeline repairs have occurred on the 76,000 miles of liquid pipelines that could affect HCAs since IM regulation was incorporated. Of those reported repairs approximately 7,000 were identified as immediate repair conditions; 5,000 as 60-day conditions; and 20,000 as 180-day conditions, respectively.[1] The good news is that somewhere in these 32,000 anomalies there were situations that would have gone to serious failure and releases, so IM is working as **one** intended safety net to address past serious failings or shortcomings in pipeline management and regulatory practices in this country. In addition, for the same time period, PHMSA reports over 35,000 liquid pipeline repairs have also been made in non-HCA areas. As a brief perspective, PHMSA also reports on its website that under gas transmission IM which is substantially different than the liquid IM regulatory approach, approximately 3,000 pipeline repairs have been made for gas pipelines in HCAs. Since pipeline repairs outside of HCAs for gas transmission pipelines are not reported (a very serious shortcoming), it is impossible to independently ascertain if there is a systemic problem on gas transmission systems, especially the type that can transgress into HCAs. Clearly, given the number of pipeline repairs, it is time for Congress to expand the IM requirements to areas beyond the HCAs.

Before discussing a major shortcoming in IM regulations, it is very important to gain a simple understanding about the four specific categories of anomalies and their repair scheduling requirements defined in liquid pipeline IM regulations.[2] These specific categories are: 1) immediate repair conditions, 2) 60-day conditions, 3) 180-day conditions, and 4) other conditions. Time does not permit me to go into great technical detail, but immediate repair conditions are usually serious corrosion or time delayed third party pipeline damage whose time to failure can be quite unpredictable. 60-day conditions are usually associated with time delayed, less severe third party damage, or poor pipeline construction practices that have damaged the bottom of the pipeline and

[1] See PHMSA liquid pipeline integrity management performance measures at http://primis.phmsa.dot.gov/iim/perfmeasures.htm.
[2] 49CFR§192452(h)(4) *Special requirements for scheduling remediation.*

that have survived an initial placed in service hydrotest pressure test, but can still result in time delayed failure. 180-day conditions are associated with lower corrosion wall loss thresholds (e.g., a wall loss threshold greater than 50% for 180-day conditions versus greater than 80% for immediate repair conditions) or smaller dent time dependent condition threats associated with more predictable time to failure calculations, but also adds indications of possible cracking, some selective corrosion, or gouging which can also fail over time. "Other conditions" is a "fallback" category clearly placing the responsibility on the pipeline operator to be vigilant and deal with any **identified** conditions that could impair the integrity of the pipeline. For the record, to avoid any possible confusion, gas transmission IM regulations have different requirements for scheduling remediation in HCAs, and as previously mentioned, no reporting requirements for anomalies in non-HCAs.

While it is good news and no surprise that over 32,000 anomalies to date have been captured and remediated under IM regulation in the approximately 76,000 miles of liquid transmission pipeline affecting HCAs, more public transparency is required in IM performance data gathering/reporting to assure that this method is thorough, and more important, appropriate. This is especially true as more risk-based performance approaches are applied by pipeline companies in both HCAs and non-HCAs. The Gulf of Mexico offshore release tragedy, if it can teach anything, clearly underscores what can happen when risk-based performance approaches step into the realm of the reckless, and prudent regulation and check and balances don't come into play to prevent such tragedies.

To its credit, PHMSA has greatly improved reporting and pubic access to more information about pipelines on its websites to improve transparency, including IM performance measures. What is critically missing in the area of IM performance measures are presentations of the results by type of repair condition (immediate repair, 60-day, 180-day, other) by kind of threat (e.g., internal corrosion, external corrosion, third party damage, construction, pipe material, etc., actually found at each repair site), by state. Reporting such analysis by state is important as many states assist PHMSA as interagency partners in the implementation of IM programs. Given the past problems uncovered by the Office of the Inspector General associated with poor industry reporting to PHMSA, it is imperative that IM data results be reported in this more detailed and systematic approach to allow independent analysis, verification, and ensure credibility and confidence in IM approaches with the public (including industry analysts, insurers, the media, etc).[3] In today's computer age, additional performance measure detail can occur with little extra effort by the companies and/or PHMSA. Congress should require changes in IM reporting as outlined earlier, and should also require PHMSA to recompile and restate the anomalies repaired to date as I believe critically important insight will be gained by this effort.

Given the wide variation in smart pig capabilities, a more "actually observed" performance reporting format will permit confirmation of the reported findings and verification that the IM processes are effective and in sync with the appropriate threats for each state. Pipeline threats can be markedly different among the states. For example, for various reasons corrosion is a substantial threat for much of the major pipeline infrastructure in Alaska, while third party damage threats should be essentially nonexistent given the highly controlled limited access environment of many of the pipelines, and the low population density in much of that state. Reporting repairs by threat type within a state will allow PHMSA, a state agency, as well as the public, to identify if there are any specific threats related to a certain area, and that an integrity management program is properly matched or failing to prudently address the threats being actually expected or experienced.

PHMSA is also now taking a vital role in inspecting pipeline construction activities that can seriously affect a pipeline's integrity and IM program over its lifecycle. Quite frankly, pipeline construction activities have historically been left on their own in this country in a jurisdictional regulatory no man's land, and I applaud PHMSA, though it may be a serious resource stretch, for now moving forward into this very important

[3] Office of the Inspector General, "Integrity Threats to Hazardous Liquid Pipelines," Report Number AV-2006-071; date issued: September 18, 2006.

pipeline construction area. Congress should assure that PHMSA has sufficient resources to perform construction inspections without harming other important efforts. Construction related threats should also be reported as part of IM performance measures. For example, recent construction inspections on new pipelines have uncovered serious problems with poor quality (e.g., pipe permanently yielding under the very important initial hydrotest and serious problems with substandard girth welds that join pipe segments).[4] The very grave issue of substandard quality new pipe resulted in PHMSA issuing an Advisory Bulletin to the industry (ADB-09-01). All IM programs obviously should track and report to PHMSA any related new construction introduced integrity threats to assure they have been properly rectified or are under control during the long lifecycle of a pipeline.

Pipeline corrosion regulations are inadequate

In reauthorizing the federal pipeline safety laws, Congress should also take stronger action on reducing the risks that corrosion poses to the integrity of hazardous liquid and gas transmission pipelines. Even with the implementation of integrity management programs, which do not cover all transmission pipeline segments, corrosion, both internal and external, is still the primary cause of liquid transmission pipeline failures in the U.S. and a major cause of gas transmission failures. This is in spite of the many advances made in pipeline corrosion prevention technology since the 1960's. Federal pipeline safety regulations are very clear in this area – corrosion control on a pipeline system is the responsibility of the pipeline operator. Current federal pipeline safety regulations for internal corrosion parrot many international standard weaknesses - an over-reliance on and over-confidence in corrosion inhibitor chemicals and their effectiveness. As the high profile BP Alaska pipeline failures and releases in 2006 attested, inhibitor chemicals are ineffective if the chemicals can't get to the steel pipe because of incomplete internal corrosion and/or maintenance programs.

[4] See PHMSA workshop on numerous problems found during just 35 inspections of new pipelines under construction at http://www.regulations.gov/search/Regs/home.html#docketDetail?R=PHMSA-2009-0060.

More recently, "PHMSA has found wide variation in operators' interpretation of how to meet the requirements of pipeline safety regulations in assessing, evaluating and remediating corrosion anomalies."[5] This raises serious concerns related to how consistent corrosion anomaly evaluations are, especially for external corrosion, and stresses the importance of modifying the reporting of IM performance measures as discussed earlier. We recommend that Congress require PHMSA to effectively deal with this serious cause of transmission pipeline failures in the U.S. It is clear that additional corrosion regulatory standards are required for pipelines both in HCA and non-HCAs (e.g., mandatory use of cleaning pigs, avoid overreliance on corrosion inhibitors), and the problem appears to go well beyond the inspection tools or methods permitted in IM rules. Ironically, smart pig technology has advanced considerably over the past three decades with regard to general corrosion identification, so the problem goes beyond blaming the tools for poor craftsmanship.

I would also caution that the number of high profile failure events related to corrosion seems to underscore that some companies appear to be diluting their corrosion control programs to save money as they overly rely on IM inspections to catch such risks before failure. Miscalls associated with assumed corrosion rates are part of this problem, especially as corrosion rates can significantly change with time. Selective corrosion, the greater corrosion threat on most pipelines, (e.g., microbiologically influenced corrosion, or MIC) have much higher corrosion rates than the general corrosion rates often cited in industry reference standards, and such selective corrosion can cause pipeline failure well before the next five-year IM regulatory reassessment interval for liquid pipelines and the seven-year reassessment interval for gas pipelines. Many would be amazed at just how fast selective corrosion, if not kept under control, can go through half-inch pipe wall, for example. It is incumbent upon the pipeline operator to have corrosion and maintenance programs to assure corrosion is under control in all segments of their pipelines and not just rely on IM inspections. For the record, IM was to serve as one level of safety and never was or is intended to replace the prudent application of internal and external

[5] See 10/22/08 PHMSA Anomaly Assessment and Repair Workshop at http://primis.phmsa.dot.gov/meeting/MtgHome.mtg?mtg=55.

corrosion programs. I would strongly suggest that Congress investigate and address this important corrosion risk of concern and require PHMSA to make improvements in both liquid and gas transmission corrosion control regulations that are intended to be supplemented by IM. I would especially advise that Congress pay special attention to gas pipelines, especially those capable of putting more tonnage of hydrocarbon into residential neighborhoods in a form that can cause greater destruction than many liquid pipelines. Gas transmission pipelines have yet to complete their baseline assessments, have longer re-inspection intervals, and different special requirements for scheduling remediation than liquid pipelines. Given the shortcomings identified in my testimony, it is too early to address the issue of modifying the reassessment intervals required by Congress for either liquid or gas pipelines. This matter is especially important for gas transmission pipelines, whose IM requirements in many areas are already less stringent, and cover much fewer pipeline miles than that for liquid pipelines.

UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Hearing on
Preventing Spills from Oil Pipelines through Integrity Management; Leak Detection; Shut-off Valves; and Corrosion Prevention

Before the
Subcommittee on Railroads, Pipelines, and Hazardous Materials
Committee on Transportation and Infrastructure
United States House of Representatives

Written Statement of Cynthia L. Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation

Expected Delivery 10:00 a.m.
July 15, 2010

WRITTEN STATEMENT OF CYNTHIA L. QUARTERMAN
ADMINISTRATOR
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
U.S. DEPARTMENT OF TRANSPORTATION
BEFORE THE
COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
SUBCOMMITTEE ON RAILROADS, PIPELINES AND HAZARDOUS MATERIALS
UNITED STATES HOUSE OF REPRESENTATIVES

July 15, 2010

Chairman Brown, Ranking Member Shuster, members of the Subcommittee, thank you for the opportunity to appear today. Secretary LaHood, the employees of the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the entire Department of Transportation (DOT) share public safety as their top priority. The Department holds a strong commitment to preventing spills on all pipelines through aggressive regulation and oversight to ensure the safety and reliability of the nation's pipeline transportation infrastructure.

PHMSA aims to improve the integrity of pipeline systems and reduce risks. This is fundamentally why PHMSA exists. In virtually every decision PHMSA makes it asks: *how does this help reduce the risk of a pipeline system failure?* Historically, PHMSA regulations consisted of prescriptive measures pipeline operators need to follow. However, over time it became clear that to adequately evaluate risk, it was necessary to understand all the system implications. To that end, the Hazardous Liquid Pipeline Integrity Management Program was created with the following objectives:

- ensuring the quality of pipeline integrity in areas with the highest potential for adverse consequences (high consequence areas or HCAs);
- promoting a more rigorous and systematic management of pipeline integrity and risk by operators;
- maintaining the government's prominent role in the oversight of pipeline operator integrity plans and programs; and
- increasing the public's confidence in the safe operation of the nation's pipeline network.

PHMSA's older prescriptive regulations and newer pipeline Integrity Management Programs work together to prevent failures and, when a failure does occur, to reduce the consequences.

PHMSA regulates approximately 497,000 miles of onshore and offshore high pressure transmission pipelines in the United States. This number includes over 173,000 miles of hazardous liquid pipelines. As a first line of defense, PHMSA's comprehensive regulations seek to prevent the leading causes of pipeline failure such as corrosion, or to mitigate pipeline failures by addressing leak detection and leak containment using leading technology and best practices. Corrosion protection mechanisms include establishing safety standards for steel pipes that address protective coatings and design criteria to prevent corrosion and reduce latent defects. In addition, operators must implement corrosion prevention technologies, including specified cathodic protection systems, electric isolation of pipelines, and atmospheric corrosion prevention methods. With respect to pipeline leak protection, operators are required to deploy a system to detect and repair pipeline leaks as soon as possible. Finally, PHMSA also ensures that hazardous liquid pipeline operators are properly using, locating, and testing relief valves and emergency flow restricting devices or shut-off valves.[1]

As an added layer of defense, PHMSA mandates operators to establish Integrity Management Programs to further protect people and the environment in or near HCAs. These programs reflect a recognition that each pipeline is unique and has its own pipeline-specific risk profile dependent on its location, operating environment, the commodity being transported, and many other factors.

This testimony provides an overview of the Hazardous Liquid Pipeline Integrity Management Program requirements and PHMSA's oversight of these programs, highlighting how these programs intersect with regulations relating to corrosion, leak detection, and shut-off mechanisms.

I. HAZARDOUS LIQUID PIPELINE INTEGRITY MANAGEMENT PROGRAMS

Ten years ago, PHMSA mandated that hazardous liquid pipeline operators develop an Integrity Management Program to identify, assess, remediate, and validate, through comprehensive analyses, the integrity of hazardous liquid pipelines that could affect HCAs. This landmark set of regulations added a broad-reaching and fundamentally different approach to improving pipeline safety. Previous concepts of pipeline maintenance and inspection focused on the pipeline itself, investigating a pipeline's physical qualities, supporting systems, the administration of an operator's inspection program, and learning from accidents. The Integrity Management regulations supplement PHMSA's safety requirements with new requirements that are more intelligent, performance and process-oriented, setting expectations for operators and requiring them to identify and address risks unique to their pipelines. Hazardous Liquid Integrity Management Programs apply only to all hazardous liquid pipelines and carbon dioxide pipelines that could affect an HCA.

Fundamentally, an Integrity Management Program seeks to identify, prevent, and mitigate the potential consequences of failure of a specific pipeline at its location. The key components of an Integrity Management Program are: (1) HCA segment identification and initial risk analysis, (2) baseline and recurring pipeline assessment, (3) remediation of certain conditions and anomalies that could cause a pipeline failure, and (4) post-assessment risk analysis and establishment of specific plans to address known threats, including corrosion.

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[1] *Relief valves are a type of valve used to limit the pressure in a pipeline system. Shut-off valves are automatic or remote controlled valves that close the flow on pipelines.*

PHMSA requires each operator to know which parts of its pipeline system could affect an HCA in the event of a failure. High consequence areas are defined as (1) high population urbanized areas or other areas with a concentrated population, (2) unusually sensitive areas, and (3) commercially navigable waterways. PHMSA applied this definition to identify HCAs and made maps depicting those areas available to operators. Operators are responsible for independently evaluating information about the area around their pipeline to identify changes in circumstance that could result in new areas becoming HCAs.

The rule further requires an operator to consider how each pipeline segment could affect an HCA. In particular an operator must consider factors they identify as relevant to their operations and the HCA, as well as PHMSA-identified common factors, the Department's technical guidance, and reports by the National Transportation Safety Board (NTSB) and the Environmental Protection Agency. Next, operators must develop processes and tools to identify and analyze their pipeline's unique risks for failure. Among the mechanisms they employ to protect HCAs, operators must employ an effective means of detecting leaks on its pipeline system.

PHMSA's Integrity Management Program emphasizes prompt and remote detection of leaks through monitoring of operational parameters and engineered leak detection systems for all pipelines. Instead of requiring computer-based leak detection systems, PHMSA addresses existing leak detection system inadequacies with each operator by analyzing and evaluating each operator's leak detection capabilities for individual pipeline systems. PHMSA encourages, and in some cases requires, timely and comprehensive adoption and application of particular technology commensurate with the system-specific needs of each operator. The use of appropriate leak detection technologies enhances an operator's ability to detect and repair hazardous liquid pipeline leaks at the soonest possible time to mitigate any damages and risks. Earlier this year, PHMSA published an advisory bulletin informing all operators of PHMSA's expectations regarding pipeline leak detection systems, not just those operating in HCAs. The bulletin stated that the operating plans and procedures required by the pipeline safety regulations should include an engineering analysis to determine whether a computerized leak detection system is necessary to improve leak detection performance and line balance processes. The advisory resulted in the closure of an NTSB recommendation.

PHMSA's regulations set requirements for installing and locating valves during a pipeline's construction, as well as periodic testing. PHMSA requires operators to install relief or shut-off valves as appropriate to protect HCAs. In making the determination of where or whether to install shut-off or relief valves, an operator must consider the following factors: (1) the swiftness of leak detection and pipeline shutdown capabilities; (2) the type of commodity being carried; (3) the rate of a potential leakage; (4) the volume that can be released; (5) the topography or pipeline profile; (6) the potential for ignition; (7) the proximity to power sources; (8) the location of nearest response personnel; (9) the specific terrain between the pipeline segment and the high consequence area; and (10) the benefits expected by reducing the spill size. While the regulations provide operators with discretion in locating shut-off valves, PHMSA inspectors ensure that the operators have adequately considered all appropriate considerations and placed shut-off valves appropriately. This determination has given operators as well as responders a greater awareness of the areas most susceptible to damage from pipeline failures.

As a result, there is now a better understanding of where these most vulnerable areas are located and where additional protection is warranted.

After the operator has identified the HCAs and the potential risks, PHMSA requires operators to assess conditions on the relevant pipelines. Figure 1 shows the most common types of assessment methods used to evaluate the risks unique to each pipeline.

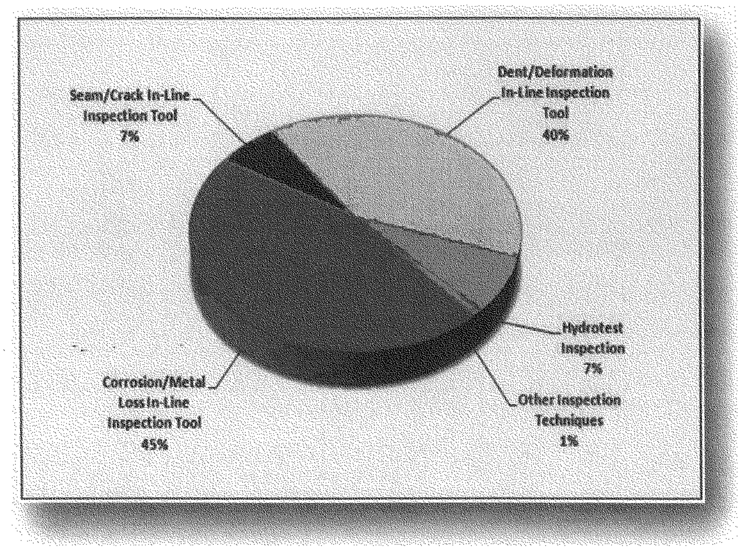

Figure 1: Types of Pipeline Inspections under the IM Rule 2001-2009

With respect to corrosion, the Integrity Management Program requires specific testing. An operator must use inline inspection tools and/or other approved inspection methods to identify corrosion and other deformities of the pipeline so that problem areas can be corrected and mitigating measures can be taken before a pipeline failure occurs. Figure 2 shows a downward trend of corrosion related accidents since the implementation of the Integrity Management Program and associated corrosion control regulations.

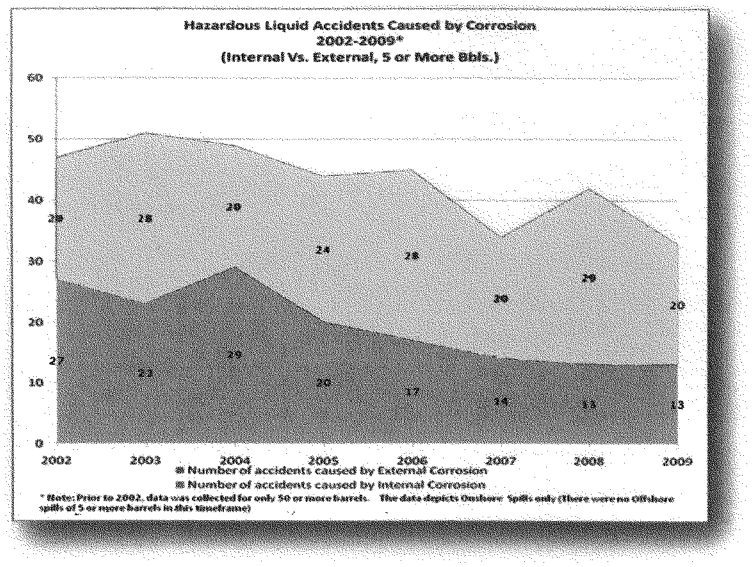

Figure 2: Onshore Hazardous Liquid Corrosion Accident Trends - 2002-2009

The Integrity Management Program imposed deadlines on hazardous liquid pipeline operators to complete an initial baseline assessment of pipelines that could affect HCAs. Approximately 44 percent of the hazardous liquid pipeline mileage falls within an area that could affect an HCA. Operators of large pipeline systems were required to complete their initial baseline assessments of all pipeline segments that could affect an HCA by March 31, 2008. Small operators with less than 500 miles were required to complete baseline assessments of their systems by February 17, 2009. PHMSA's inspections and the mandated annual reporting by operators (certified by company executives) have shown that these deadlines were met. Operators are now conducting the second round of assessments of these same pipeline segments. This assessment will increase our overall knowledge about the condition of the nation's pipelines in and beyond HCAs. Operators have internally inspected, pressure tested, or otherwise assessed approximately 86 percent of the total hazardous liquid pipeline mileage, well beyond areas designated as those that could affect an HCA.

Operators must remediate anomalies identified during their assessments that meet a certain defined criteria in a timely manner. PHMSA has defined the remediation timeframes for various types of anomalies. To date, Integrity Management Program pipeline assessments have revealed over 35,000 dangerous conditions within HCAs that pipeline operators have remediated. An additional 78,000 anomalies that were identified, but were not categorized as constituting dangerous conditions have been remediated, many of which were outside of HCAs. Those anomalies were not required to be repaired by the Integrity Management Program, but were discovered and proactively remediated as a result of assessments. Figure 4 depicts the number of repairs completed over and above those required by the Integrity Management Program regulations.

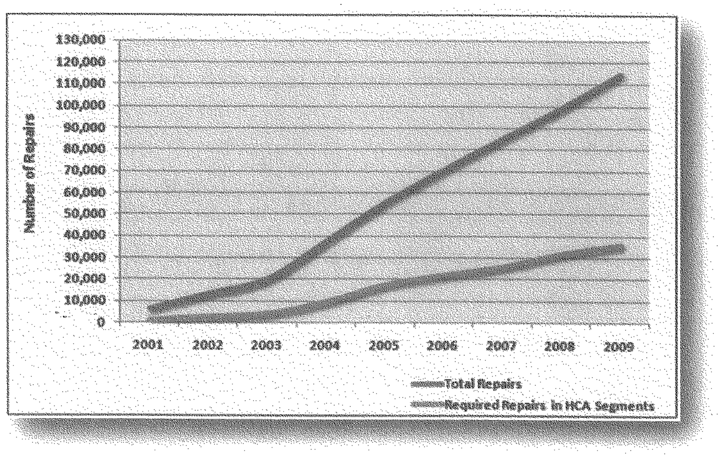

Figure 4: Repairs Made Under the Liquid IM Rule 2001-2009 (Cumulative)

After the initial assessment and remediation efforts, the Integrity Management Program requires operators to establish systematic approaches for using risk assessments to identify and implement additional preventive and mitigative measures. For example, operators must develop and implement a plan to mitigate the potential effects of corrosion if their assessments indicate corrosion risks. Pipeline operators are required to monitor the effectiveness of their preventive and mitigative programs, and re-evaluate the program if there are changed circumstances.

The Integrity Management Program goes beyond simply assessing pipeline segments and repairing defects. Improving operator Integrity Management Programs, analytical processes, and their application is also a critical objective. The ability to integrate and analyze threat and integrity related data from many sources is essential for proactive safety management.

II. PHMSA'S OVERSIGHT AND ENFORCEMENT OF INTEGRITY MANAGEMENT PROGRAMS

PHMSA developed an inspection program to assure compliance with the Integrity Management Program requirements. It also developed a comprehensive set of inspection protocols that not only check for compliance with the regulation's prescriptive requirements, but also support a detailed audit of an operator's management and analytical systems, processes, and practices on pipeline integrity. PHMSA developed a specialized training program for federal and state inspectors to inspect these protocols. To date, 383 Federal and State inspectors have been trained to inspect Integrity Management Programs. The Integrity Management Program of every operator PHMSA regulates has been inspected at least once. All large hazardous liquid pipeline operators have been inspected a second time to be sure they are continuing to manage pipeline integrity and making progress in building robust and effective Integrity Management Programs.

When operators fall short of meeting the requirements for Integrity Management Program development, PHMSA takes enforcement action to accelerate program development and address program deficiencies with the individual operators. PHMSA issued enforcement letters in 85% of all its Integrity Management inspections. PHMSA also has not hesitated to exercise its civil penalty authority when violations of the rule's requirements occur.

PHMSA also ensures that operators comply with corrosion standards though inspection and aggressive enforcement. PHMSA has initiated 272 enforcement cases resulting from 657 probable violations or procedural inadequacies involving corrosion problems since 2000. It has proposed $1,798,950 in fines on those actions. In addition, many of the Integrity Management enforcement actions addressed corrosion issues.

Similarly, PHMSA inspectors have identified a number of issues related to an operator evaluation of their leak detection capabilities using the Integrity Management inspection protocols. PHMSA has initiated enforcement actions, or formally documented its concerns, with respect to approximately 40 percent of hazardous liquid pipeline operators to date. In response to the enforcement actions, operators are required to submit revised procedures to correct inadequacies in their leak detection evaluations. Operators must then evaluate (or reevaluate) their leak detection capabilities in accordance with these corrected procedures. Before a case is closed, PHMSA reviews the revised procedures, and determines that the revisions satisfactorily address identified issues.

Transparency has been a hallmark of PHMSA's regulatory oversight. PHMSA has a website for Implementing Integrity Management to provide information to the public on the rule as well as PHMSA's oversight of the program. This publicly accessible website includes hundreds of Frequently Asked Questions to explain the rule's provisions and PHMSA's expectations. This resource also provides the inspection protocols, an Integrity Management fact sheet, a glossary, a flow chart of the Integrity Management process, reference documents, and industry performance measures. The public also has access to information on enforcement cases stemming from PHMSA's Integrity Management inspections via the website. PHMSA has taken unprecedented steps to inform the public and all other stakeholders about the protections provided by the Integrity Management Program and PHMSA's oversight.

PHMSA looks forward to seeing Integrity Management Programs continue to mature and yield results. With this in mind PHMSA will continue to look at performance measures and ways we can improve the data that we collect. Having better data will enable PHMSA to make risk based informed regulatory decisions.

With anticipated increases in transportation of new products like ethanol, hydrogen, carbon dioxide, and potentially other bio-fuels, PHMSA is working to ensure a solid regulatory framework to prevent accidents and ensure safety. PHMSA is committed to taking whatever steps are necessary to ensure that such transportation will be conducted safely. We coordinate with other federal agencies to forecast the transportation implications from the inception of marketing new fuels, as part of a systemic oversight process. We coordinate with other countries to benefit from their experience. We continue to work with individual operators, identifying safety concerns that must be satisfied, both with the infrastructure and with the surrounding community. We continue to collaborate with the pipeline industry, emergency response organizations, and others to investigate and solve technical challenges.

In closing PHMSA looks forward to working with Congress to address issues related to hazardous liquid pipeline safety, including finding ways to prevent pipeline failures and mitigate the effect of any failure. PHMSA very much appreciates the opportunity to report on the status of our progress in preventing spills from hazardous liquid pipelines.

Thank you. I would be pleased to answer any questions you may have.

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