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Testimony of the Honorable Deborah A.P. Hersman
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National Transportation Safety Board
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Pipeline Safety: An On-the Ground Look at Safeguarding the Public
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Chairman Rockefeller, Members of the Committee, and Senator Manchin, thank you for the opportunity to address you today concerning the National Transportation Safety Board's (NTSB) ongoing investigation of the pipeline rupture and fire in Sissonville, West Virginia, 7 weeks ago.

Mr. Chairman, as you have indicated, this is the fourth Senate Commerce Committee hearing on the issue of pipeline safety during your tenure as chairman. This hearing is also the NTSB's fourth Senate Commerce Committee hearing on this issue since I became Chairman. It is regrettable that major pipeline safety accidents continue to be a significant transportation and public safety concern. It is also regrettable that in the area of pipeline safety, philosopher George Santayana's aphorism that those who do not learn from history are doomed to repeat it, is certainly true. Indicative of the safety risks posed by pipelines, just four weeks prior to the Sissonville accident, the NTSB added pipeline safety to its Most Wanted List of the top 10 transportation safety challenges for 2013—the first time this general subject has appeared on our annual List.

Today, I will discuss the safety risks posed by the transportation of oil and natural gas by pipeline, the rupture and fire that occurred in Sissonville on December 11, 2012, the NTSB's response to the accident and the status of its investigation, and key NTSB findings and recommendations as the result of its past investigations of major pipeline accidents.

As described in our Most Wanted List, today, in the United States there are some 2.5 million miles of pipelines transporting natural gas, oil, and other hazardous liquids, with a significant amount of new pipeline design and construction activity underway. The pipeline network in this country includes 300,000 miles of gas transmission pipelines. Because pipelines are usually underground, most people don't even know they exist, much less where they are located. Therefore, it is incumbent on pipeline operators and regulators to ensure that the nation's pipelines are safe. Sufficient resources should be available to regulators to carry out critical oversight and enforcement efforts. These pipelines power thousands of homes and deliver important resources, such as oil and gasoline, to consumers. While one of the safest and most efficient means of transporting these commodities, there is an inherent risk that can lead to tragic consequences, especially when safety standards are not observed or implemented.

As was evident in Sissonville last December 11, pipeline ruptures can cause significant damage. Last July, the NTSB issued its accident report for the July 2010 hazardous liquid pipeline rupture in Marshall, Michigan—a rupture that was not discovered for over 17 hours. As a result, almost 850,000 gallons of crude oil spilled into the surrounding wetlands and flowed into local waterways, costing nearly a billion dollars to date for clean-up and recovery—by far the most expensive environmental clean-up for an onshore oil spill. Also, in September 2010, one of the worst gas pipeline ruptures occurred in San Bruno, California, when a natural gas transmission pipeline ruptured and ignited, killing 8 persons. In addition, 58 persons were injured, 38 homes were destroyed and 70 more were damaged as a result of this horrific and tragic accident.

THE SISSONVILLE ACCIDENT

On December 11, 2012, at about 12:41 pm eastern standard time, a buried 20-inch diameter natural gas transmission pipeline (Line SM-80), running west to east, perpendicular to Interstate 77, and owned and operated by Columbia Gas Transmission Corporation, ruptured about 112 feet west of Interstate 77 in Sissonville, Kanawha County, West Virginia, near Route 21 and Derricks Creek. The pipeline maximum allowable operating pressure (MAOP) was 1,000 pounds per square inch gauge (psig), and the operating pressure at the time of the rupture was about 929 psig. After the escaping high-pressure natural gas ignited, fire damage extended nearly 1,100 feet along the pipeline and about 820 feet wide. About 20 feet of pipe was ejected from the underground pipeline and landed more than 40 feet from its original location.

The rupture occurred in a pipe that was a part of a pipeline segment installed in 1967 with a nominal wall thickness of 0.281 inches. The 20-foot ejected section of the pipe was found to have a fracture along the entire longitudinal direction at the bottom of the pipe. The outside surface of the pipe was heavily corroded near the midpoint and along the longitudinal fracture. The thinned area was approximately 6 feet in the longitudinal direction and 2 feet in the circumferential direction. The wall thickness had degraded so significantly that it measured only 0.078 inches at the point along the fracture—about 70 percent thinner than the uncorroded pipe.

The force of the released gas created a crater about 75 feet long by 35 feet wide and up to14 feet deep. Escaping high-pressure natural gas from the ruptured pipeline ignited. The intense fire destroyed three near-by homes, caused damage to several others, and heavily damaged both the northbound and southbound lanes of I-77, closing both lanes for about 14-19 hours until the roadway surfaces were repaired.

The first call to 911 about the pipeline rupture and fire was made by a person at a nearby retirement home at 12:41 p.m. At 12:43 p.m. the Columbia Gas controller on duty at the gas control center in Charleston, West Virginia, began receiving alerts on the Supervisory Control and Data Acquisition (SCADA) system from instrumentation at the Lanham Compressor Station, located 4.7 miles upstream from the rupture location. Over the next ten minutes, 16 SCADA alerts indicated that the discharge pressure was dropping on Line SM-80 and two other pipelines in the SM-80 system (Line SM-86 and Line SM-86 Loop). The first notification to the Columbia Gas control center in Charleston, West Virginia, was provided by a controller from Cabot Oil and Gas Company at about 12:53 p.m., who had received a report of a "huge boom and flames shooting over the interstate" from a field technician who was near the accident location. Columbia Gas SCADA data indicate that the discharge pressures on the three pipelines leaving Lanham had dropped about 100 psig.

At about the same time that the control center was notified of the rupture, a Columbia Gas Operations Manager was called by a separate Columbia Gas field operator and told about the release and fire. The Operations Manager sent a crew to the Rocky Hollow valves approximately 3.2 miles downstream of the rupture, where two technicians, closer to the accident site, had already self-dispatched. Columbia Gas field technicians closed the downstream isolation valves at about 1:19 p.m., preventing the backflow of gas. The Operations Manager also notified personnel at the Lanham compressor station to shut the upstream valves. The 6 valves at the Lanham compressor station required a technician for closure. Technicians started closing the valves at 1:15 p.m., and notified the Operations Manager at 1:40 p.m. that the valves were fully closed, stopping gas flow to the rupture nearly one hour after the rupture occurred.

THE NTSB'S INVESTIGATION

After learning of the accident, a 10-person team from the NTSB, led by Board Member Robert Sumwalt, launched to Sissonville. According to our team's surveys conducted at the accident site, the rupture occurred in a nearly 38-foot long pipe joint that was a part of the pipeline segment installed in 1967. According to Columbia Gas documents, the ruptured segment of Line SM-80 was pressure tested twice in 1967: first at about 1,800 psig and then at about 1,750 psig. According to Columbia Gas records, the nominal wall thickness of the 20-inch ruptured pipe segment was 0.281 inches, had a longitudinal electric resistance weld seam, and was manufactured according to American Petroleum Institute specifications.

Parties to the Investigation are: Pipeline and Hazardous Materials Safety Administration, (PHMSA), Public Service Commission of West Virginia, Columbia Gas Transmission Corporation, Kanawha County Sheriff's Office, and West Virginia State Police South Charleston Detachment.

The NTSB issued a preliminary report on the Sissonville accident on January 16. Our investigative work, including metallurgical analysis of sections of the ruptured pipe at our laboratory in Washington, DC, is ongoing. Additional reports, analysis and a finding of probable cause will come later in the investigation.

RECURRING PIPELINE SAFETY ISSUES

Although it is premature for the NTSB to determine the cause of the Sissonville accident, issue findings, or draw conclusions, there are a number of recurring safety issues we have identified in previous pipeline accidents we have investigated that merit highlighting today. In particular, these safety issues include:

- Automatic and/or remote control shut-off valve installation
- Use of in-line inspection tools
- Integrity management program

- SCADA training

Automatic and/or remote control shut-off valves

The NTSB has long been concerned about the lack of standards for rapid shutdown and the lack of requirements for automatic shutoff valves (ASV) or remote control valves (RCV) in high consequence areas (HCA) and class 3 and 4 areas. As far back as 1971, the NTSB recommended the development of standards for rapid shutdown of failed natural gas pipelines. In 1995, the NTSB recommended that the Research and Special Programs Administration—the predecessor agency of PHMSA—expedite requirements for installing automatic- or remote control valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. The current PHMSA integrity management regulation, which was promulgated in 2003, leaves the decision whether to install ASVs or RCVs in HCAs to the gas transmission operator.

In Sissonville, it took the operator approximately 58 minutes after the pipeline rupture and explosion to stop the gas flow by closing manual shutoff valves. Although the operator did not identify an HCA associated with the site of the Line SM-80 rupture, as the NTSB has pointed out in previous accidents involving pipelines located in an HCA, the availability of ASVs or RCVs is an important tool in containing the safety risks after a pipeline rupture.

Use of in-line inspection tools

One of the 13 recommendations the NTSB made to PHMSA as a result of the San Bruno pipeline rupture and fire is to require all natural gas transmission pipelines be configured to accommodate in-line inspection (also known as internal inspection) tools with priority given to older pipelines. This recommendation was predicated on the NTSB's concern that in-line inspection is not possible in many of the nation's pipelines, which—because of the date of their installation—have been subjected to less scrutiny than more recently installed pipelines. As indicated earlier, the Sissonville rupture occurred in a pipeline segment installed in 1967. Due to construction limitations such as sharp bends and the presence of plug valves, many older natural gas transmission pipelines, including the ruptured segment in Sissonville, cannot accommodate modern in-line inspection tools without modifications.

In-line inspection tools travel through the pipeline to determine the nature and extent of any anomalies in the pipe. Another option for this type of testing is hydrostatic pressure testing that yields information about the integrity of the pipeline.

In the NTSB's judgment, the use of specialized in-line inspection tools that identify and evaluate damage caused by corrosion, dents, gouges, and circumferential and longitudinal cracks is a uniquely promising option. Unlike other assessment techniques, only in-line inspection can provide visualization of the pipeline integrity throughout the entire pipeline segment and, when performed periodically, can provide useful information about corrosion and crack growth. Although in-line inspection technology has detection limitations (generally a 90 percent probability that certain type of anomalies will be detected), the probability of detecting a crack may be improved with multiple runs, and it is nonetheless a more effective method for detecting unacceptable internal and external pipeline anomalies before a leak or rupture occurs.

Integrity management system assessments

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, enacted a little more than one year ago, includes a provision requiring the Secretary of Transportation to evaluate whether integrity management system requirements first set forth in the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (the PIPES Act), should be expanded beyond HCAs and report the analysis findings to this Committee and the Committee on Transportation and Infrastructure, U.S. House of Representatives, by early next January. If the Secretary determines that integrity management system requirements should be expanded beyond HCAs, the Secretary must issue regulations to implement these requirements after a Congressional review period has elapsed.

Although the NTSB certainly welcomes the statutorily-required evaluation and recognizes that Columbia Gas and other operators of natural gas transmission pipeline facilities in non-HCAs are not required to establish integrity management programs that meet minimum performance standards established in PHMSA regulations, the NTSB views these programs as important business practices that these operators should consider for implementation. In our San Bruno, California and Marshall, Michigan, investigations, we determined the Pacific Gas and Electric Company and Enbridge Incorporated, respectively—both of whom must comply with PHMSA's integrity management program requirements—nonetheless had ineffective programs. Deficiencies identified by the NTSB included use of inappropriate inspection methods and tools and failures to detect pipeline defects.

The NTSB does, however, recognize that achieving a robust and effective integrity management program—whether mandated or voluntary—requires dedication, sustained effort, and resources.

SCADA training

As indicated above, the Columbia Gas controller on duty received 16 "pressure-drop" alerts—but did not receive any "critical" alarms—on the SCADA system, before receiving notification from another pipeline operator. These alerts showed the discharge pressure dropping on Line SM-80 and the two other pipelines in the SM-80 system.

The NTSB has addressed SCADA training in a number of instances. In 2005, the NTSB conducted a study of SCADA in liquid pipelines. The study examined the role of SCADA systems in 13 hazardous liquid line accidents investigated between 1992 and 2004. In ten of the accidents cited by the study, there was a delay in recognizing the leak by the control center operators. As a result of one of the NTSB safety recommendations resulting from this study and requirements enacted in the PIPES Act, in December 2009, PHMSA promulgated its control room management rule for pipeline facilities in Title 49, Code of Federal Regulations, section 192.631.

In the Marshall, Michigan pipeline rupture, the NTSB determined that inadequate training of control center personnel allowed the rupture to remain undetected for 17 hours, including two startups of the pipeline. In the San Bruno, California accident, the NTSB found "that it was evident from the communications between the SCADA center staff, the dispatch center, and various other PG&E employees that the roles and responsibilities for dealing with such emergencies were poorly defined."

As part of its investigation in Sissonville, the NTSB is looking into the operator's control room operations, its SCADA system, and the capabilities and training of its control room staff.

Closing

Although the rupture and fire did not result in any fatalities or serious injuries, the Sissonville accident could easily have caused significant injuries and fatalities. Pipeline accidents that have occurred in San Bruno, California; Marshall, Michigan; Sissonville; and elsewhere are devastating to the affected communities. Particularly regrettable are the recurring frequency of these accidents and the resource constraints that hamper regulators' pipeline safety oversight.

This concludes my testimony and I would be happy to answer any questions you may have.