Pipeline Safety New Voices Project

Briefing Paper #3 - Hazardous Liquid Pipelines - Basics and Issues

Here is the third briefing paper in the series. Much of the information included in the last paper on natural gas pipelines, such as the types of pipelines and basic construction information is for the most part the same for hazardous liquid pipelines, so we have tried to not repeat ourselves too much.

What Do Hazardous Liquid Pipelines Carry?
Hazardous liquid pipelines, as defined in federal regulations, carry:

- **Crude oil**, with widely varying densities, viscosities, sulfur contents, and other properties, including bitumen (an extra heavy crude oil), which is typically diluted with condensates to make it flow through pipelines. “Sweet” crude refers to crude that contains little or no sulfur, while “sour” crude contains high concentrations of sulfur or hydrogen sulfide.
- **Refined petroleum products**, including gasoline, diesel, jet fuel, and home heating oil.
- **Highly Volatile Liquids** such as propane, butane, ethylene, condensates
- **Carbon dioxide**
- **Anhydrous Ammonia**

One other liquid associated with oil and gas drilling that is frequently transported by pipeline is produced water or wastewater from drilling activities. This liquid is not currently regulated under the federal pipeline safety rules. States can regulate these lines if they choose, and spills of this produced water may fall under state and federal pollution regulations such as the Clean Water Act.

If you are interested in seeing what types of materials the transmission pipelines in your state carry PHMSA has provided the mileage of pipelines carrying each commodity on their state pages [here](#). Go to the “incident and mileage data” link for your state and there is then information on miles of pipeline for each commodity, miles in each county, and incident data. Pictured here is a sample of the commodity breakdown for Nebraska.

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Pipeline Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>AA - Anhydrous Ammonia HVL (Highly Volatile Liquid)</td>
<td>311</td>
</tr>
<tr>
<td>CRD - Crude Oil</td>
<td>435</td>
</tr>
<tr>
<td>EPL - Empty Liquid</td>
<td>5</td>
</tr>
<tr>
<td>LPG - Liquefied Petroleum Gas HVL (Highly Volatile Liquid)</td>
<td>289</td>
</tr>
<tr>
<td>NG - Natural Gas</td>
<td>5,826</td>
</tr>
<tr>
<td>NGL - Natural Gas Liquids HVL (Highly Volatile Liquid)</td>
<td>192</td>
</tr>
<tr>
<td>OHV - Other HVL (Highly Volatile Liquid)</td>
<td>170</td>
</tr>
<tr>
<td>PRD - Refined Products</td>
<td>1,033</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>8,262</strong></td>
</tr>
</tbody>
</table>
**How Hazardous Liquid Pipelines Work**

For the most part liquid pipelines operate and are constructed in the same basic way that natural gas lines are, so we are not going to repeat all that again.

Raw crude coming out of a well normally needs to go through separation to remove water and gas from the crude. Gathering lines bring crude oil out of production areas and to larger transmission lines that often take the crude oil to refineries.

![Diagram of pipeline system]

Once the crude oil has been refined, transmission lines carry the refined products to end-users or to storage and distribution facilities for transportation to consumers. The product is pushed through the pipeline by large pump stations situated every 20-100 miles along the line depending on the product, terrain and pressure at which the pipeline is operating.

The machinery at the pump stations is normally controlled remotely at centralized control stations. Most liquid fuels move through the pipeline at between 3 to 8 miles per hour. It is estimated that the cost of transporting the crude oil and then the refined products through the pipeline network adds about two and a half cents to the cost of a gallon of gasoline at the pump.

A single pipeline can carry several different types of refined products in “batches,” shown in an animated illustration here: [http://www.pipeline101.com/Operating/batching_model.html](http://www.pipeline101.com/Operating/batching_model.html)

Typically, the pipeline operator does not own the product in the pipe; the operator simply gets paid to move the product from one place to another. Interstate transmission pipeline companies develop “tariffs” that are approved by the Federal Energy Regulatory Commission (FERC), that set the price for
moving the product and describe the specifications that need to be met before the product can be transported through the transmission pipeline. These tariffs for crude oil for example would define things such as the allowable water and sediment content, temperature, density and viscosity of the crude. Companies normally publish their tariffs online, for example [click here](#) to see TransCanada’s tariffs for their Keystone pipeline.

**Regulations Affecting Hazardous Liquid Lines**
Liquid pipelines, depending on location, are subject to regulations by the following agencies:

- Safety – PHMSA, States
- Spill Response – PHMSA, Coast Guard, States
- Spill Cleanup – EPA, Coast Guard, States
- Security – TSA and Coast Guard
- Pricing/tariffs – FERC
- Storage terminals – EPA
- Worker safety – OSHA

Fewer states have chosen to seek any authority over the safety of hazardous liquid pipelines than over natural gas pipelines. Currently 17 states have some authority over intrastate liquid lines (compared to 48 states for natural gas lines), with only six states seeking any authority on interstate liquid transmission pipelines (compared to 9 for natural gas).

**Major Pipeline Safety Requirements For Hazardous Liquid Pipelines**

**Integrity Management**
Integrity management for liquid lines is similar to integrity management for natural gas lines, and we will cover this in much more depth in a future paper. Requirements for integrity management plans have been in place since 2002.

Integrity management refers to the set of rules that requires operators of transmission lines to identify and assess all threats to a particular pipeline segment, whether from internal or external corrosion, flooding, landslides, excavation damage, welds or construction defects, etc.; and to produce an integrity management plan designed to routinely assess those threats and undertake any necessary repairs or replacements, improve cathodic protection or take other actions necessary to maintain the pipeline’s safety. The rules apply to pipelines that could affect a High Consequence Area (HCA) in the event of a spill. For liquid lines, HCAs include defined densities of populated areas, unusually sensitive areas (USAs) like drinking water sources and commercial or recreational fishing areas, and commercially navigable waterways.

The original rule gave companies until 2009 to complete an initial baseline assessment of their pipelines in HCAs. Each covered pipeline segment must then be re-assessed at least every 5 years. About 44% of all hazardous liquid pipelines fall within HCAs, so are covered by this program. Because of the way the various assessment methods (mainly smart pigs) are used in pipelines many more miles of pipeline have actually been assessed than required by the rules. Below is a chart that shows how many problems were found and repaired on liquid pipelines because of this rule.
Identification of Threats and Repair of Pipelines Outside of HCAs

Identifying threats and repair of pipelines outside of the integrity management requirements (HCAs) are left pretty much up to the good judgment of the pipeline operator. The regulations allow the operator to decide how to look for problems and what a “reasonable time” is to correct a problem that may be discovered. There are defined periods for inspections of things such as valves and regulators. The green box to the right provides the overarching regulation that puts the responsibility for safe operation and repair on the pipeline operator.

Emergency Response and Spill Response Planning

Federal regulations require emergency response plans for both liquid and gas pipelines, and also require that operators share those plans with local first responders. These emergency response plans contain information about what the pipelines contain, and how pipeline company personnel and emergency response agencies such as fire and police departments will implement pre-planned response in case of an emergency.

Hazardous liquid pipeline operators are also required to have spill response plans that detail how they will respond to clean up a spill if one should happen. These plans include worst case scenarios, and detailed information about the quantities and location of where spill equipment and personnel are located and how quickly they can respond to situations in various locations. Currently PHMSA approves these plans for all onshore liquid pipelines, but it is very difficult for the public to obtain and review these plans. The federal pipeline safety bill recently enacted will require some aspects of those response plans to be publicly available.

The Oil Pollution Act of 1990 expressly allows states to institute additional and more stringent spill response planning requirements for oil pipelines and facilities, but only a few have done so. In Washington, for example, spill response plans must be submitted to a state agency for approval, must meet certain minimum standards, and are subjected to a period of public review and comment. Once approved, they remain available to the public.

A recent news article highlights the benefits of having publicly available spill prevention and response plans, and access to an operator’s compliance reports. The Prince William Sound Regional Citizen’s Advisory Committee, established under the terms of the Oil Pollution Act of 1990 following the Exxon

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**Hazardous Liquid Pipeline Repairs**

<table>
<thead>
<tr>
<th>Repairs in HCA-affecting segments</th>
<th>2001-2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Immediate category</td>
<td>1,191</td>
<td>1,701</td>
<td>1,369</td>
<td>941</td>
<td>882</td>
<td>888</td>
<td>653</td>
<td>7,625</td>
</tr>
<tr>
<td>• 60-day category</td>
<td>756</td>
<td>647</td>
<td>1,109</td>
<td>861</td>
<td>581</td>
<td>1,022</td>
<td>452</td>
<td>5,428</td>
</tr>
<tr>
<td>• 180-day category</td>
<td>2,397</td>
<td>3,178</td>
<td>5,278</td>
<td>2,748</td>
<td>2,144</td>
<td>4,037</td>
<td>3,055</td>
<td>22,837</td>
</tr>
<tr>
<td>Other repairs in HCA-affecting segments and repairs outside of these segments</td>
<td>16,081</td>
<td>11,782</td>
<td>10,219</td>
<td>10,841</td>
<td>11,114</td>
<td>8,221</td>
<td>11,314</td>
<td>79,572</td>
</tr>
<tr>
<td>Total repairs both in and outside of HCA-affecting segments</td>
<td>20,425</td>
<td>17,308</td>
<td>17,975</td>
<td>15,391</td>
<td>14,721</td>
<td>14,106</td>
<td>15,474</td>
<td>115,462</td>
</tr>
</tbody>
</table>

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**The Regulations**

**Repairs Not Required by Integrity Management 49 CFR 195.401(b)(1)**

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.
Valdez spill, commissioned a consultant’s report to review the compliance efforts by Alyeska to its spill prevention and response plan, and raised significant questions about whether Alyeska was meeting the requirements of its own plan. To read that story click here.

Corrosion
Much of the major corrosion protection items (coatings, cathodic protection, inhibitors) for hazardous liquid pipelines are the same as for natural gas pipelines. Here is a brief discussion of corrosion.

What is corrosion and why does it occur?
Corrosion is the deterioration of metal that results from a reaction with the environment which changes the iron contained in pipe to iron oxide (rust). For example, if your car develops a rust spot, that is corrosion of metal. The same process can occur in various forms on pipelines. As is the case with your car, there are effective methods for preventing and arresting corrosion damage to pipelines.

- **External corrosion** occurs due to environmental conditions on the exterior surface of the steel pipe (e.g., from the natural chemical interaction between the exterior of the pipeline and the soil, air, or water surrounding it).
- **Internal corrosion** occurs due to chemical attack on the interior surface of the steel pipe from either the commodity transported or other materials carried along with the commodity transported within the pipeline.
- **Other, more specialized types of corrosion** such as stress corrosion cracking, microbial corrosion, and selective seam corrosion can also occur. These types of corrosion can be exacerbated by environmental conditions, manufacturing processes and applied stresses resulting from routine and normal pipeline operations.

What are the risks from corrosion? Corrosion can result in the gradual reduction of the wall thickness of the pipe and a resulting loss of pipe strength. This loss of pipe strength could then result in leakage or rupture of the pipeline due to internal pressure stresses unless the corrosion is repaired, the affected pipeline section is replaced, or the operating pressure of the pipeline is reduced. Pipeline corrosion creates weaknesses at points in the pipe, which in turn makes the pipe more susceptible to other risks such as third party damage, overpressure events, etc.

Leak Detection
Operators are not currently required to have electronic leak detection systems on their pipelines. Leak detection sensitivity is a reflection of the systems’ capability to detect a leak of a certain size in a predetermined time. While many operators do employ multiple leak detection systems there is no standard for how quickly they have to be able to identify leaks of any certain size. Small leaks are the most difficult to detect, and take the longest time to set off an alarm. Some small leaks may fall below the threshold of leak detection systems, due to pipeline hydraulics, accuracy of the detectors, and alarm thresholds. Even the best leak detection systems may not be able to detect “small” leaks under 3% of the volume of the flow through the pipeline.

The effectiveness of leak detection systems has been called into doubt by many recent incidents:
• 2010 Enbridge spill in Marshal Michigan, over 800,000 gallons of crude oil spilled and went undetected by the company’s leak detection system.
• 2010 Chevron spill in Salt Lake City, over 30,000 gallons of crude oil went undetected by the company’s leak detection system.
• 2011 TransCanada Keystone I pump station leak of 21,000 gallons of crude oil was reported by neighbor who saw a geyser of oil before TransCanada identified leak and shut down pipeline.

The recent pipeline safety reauthorization bill includes a provision calling for a study of the state of the art for leak detection systems on liquid lines, requires a report back to Congress, and prohibits a final rulemaking by PHMSA requiring leak detection systems within 3 years, unless the Secretary finds that requiring them will address an “imminent hazard.”

**Valves – Type & Placement**

Liquid lines have the same valve considerations as natural gas lines. If a pipeline should fail, how quickly the valves can be closed and the distance between the valves are some of the main determinations for how much fuel is released. One term you may run into is Emergency Flow Restricting Device (EFRD). For the most part EFRD refers to either a check valve (a valve that allow fluid to only flow in one direction) or a remotely controlled valve that can be shut off from a control room. The placement of such valves near high consequence areas, particularly water crossings, can reduce the amount of fuel spilled if a pipeline failure should occur.

For liquid pipelines in 1992, 1996, 2002, and 2006, Congress required PHMSA’s or its predecessor to “survey and assess the effectiveness of emergency flow restricting devices” with the first such requirement having a deadline in 1994. Following this analysis, Congress required PHMSA to “prescribe regulations on the circumstances under which an operator of a hazardous liquid pipeline facility must use an emergency flow restricting device.”

PHMSA never issued a formal analysis on emergency flow restricting device (EFRD) effectiveness. Instead, in its hazardous liquid pipeline integrity management rule, they chose to leave EFRD decisions up to pipeline operators after listing in the rule various criteria for operators to consider. In our opinion such an approach to EFRD use does not appear to meet Congressional intent, partly because the approach is essentially unenforceable and not protective of important environmental assets.

Congress again in the recent pipeline safety reauthorization bill asked for a study of such valves and required PHMSA to move forward with regulations to require the use of such valves “where economically, technically, and operationally feasible” based on the findings of the study if they think that such use is “appropriate.”

**For further information:**

PHMSA’s Pipeline Library

How Pipelines Make the Oil Market Work, Allegro Energy Group, December 2001

Next up: The statutes, regulations, consensus standards, and best practices