
A Regulatory Review of Liquid and Natural Gas Pipelines in Colorado

December 2014

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This document is the work product of representatives of the pipeline industry, federal and state regulators, elected officials, and local governments. It provides an overview of hydrocarbon pipeline regulation in Colorado from the wellhead through the midstream distribution network, and does not address downstream pipelines to the final, metered point of sale. Pipeline networks are complex with multiple jurisdictional points of oversight. This document is intended to provide a broader understanding of the scope of regulatory oversight of these pipeline operations for the public, local governments, regulators, and those who are regulated. Regulatory changes will be reflected in future versions of this “living” document.

I. Introduction

Pipeline networks of every type (e.g., energy products, water and wastewater, chemical products) represent a largely unobtrusive and ubiquitous transportation infrastructure that brings direct societal advantage. As a (largely) buried infrastructure, pipelines do not normally interfere with routine human activities on the surface such as building, agriculture, or transport of people and products via roadway. In this regard, pipelines can be an effective and virtually continuous and uninterrupted transport mode.

Regarding hydrocarbons specifically, in the United States pipelines transport nearly two-thirds of the petroleum products, and nearly all of the natural gas. The United States’ pipeline system is composed of more than 2.6 million miles of pipeline. Liquid pipelines transport crude oil or natural gas liquids from producing fields to refineries, where they are turned into gasoline, diesel, and other petroleum products. Natural gas pipelines transport gas from wells, to processing plants, and then to distribution systems that take the natural gas directly to homes and businesses.

Both liquid and natural gas pipeline infrastructure can be broken down into four categories:

- (1) Flowlines contain produced wellhead fluids from individual wells that feed production facilities near the wellhead;
- (2) Gathering pipelines tie production facilities with gathering systems that feed into oil storage or natural gas processing facilities;
- (3) Transmission pipelines transport pure natural gas and hydrocarbon liquids (refined or unrefined) over long distances; and
- (4) Distribution pipelines deliver pure natural gas to end users (residential, commercial, industrial).

Visuals of pipeline infrastructure can be found in Appendices A-1 and A-2.

Four general industry segments use this infrastructure along the route to market: Upstream exploration and production systems, midstream gathering systems, downstream transmission systems, and end-use distribution systems:

- (1) The upstream segment includes exploration and production (E&P) and well drilling activities. Advanced seismic surveys assist exploration companies in finding the resources they wish to

develop. Once the resource is found and the drilled oil is piped to on-site storage tanks and raw gas is metered, and the transportation to market begins;

(2) The midstream gathering and processing (G&P) segment collects hydrocarbons starting at a meter point near the well site for processing;

(3) The downstream segment includes processing, transmission, and storage; and

(4) The end-use segment represents the final market transport through local distribution companies or a gas utility company.

Pipelines are an effective mode to transport hydrocarbon liquids and natural gas to market and are by far the safest method for transporting large volumes of energy products. Pipelines do not contribute to traffic congestion on our country's highways and waterways as trucks and barges can, nor do pipelines contribute to highway accidents. When pipeline incidents occur, however, they can present significant risks to populated areas and the environment, making information about the current regulatory structure so important.

A. Oil & Gas Production and Transportation

Pipelines naturally follow where hydrocarbon production succeeds and markets mature. On the highest level, the development of a pipeline network is a very organic process. In-basin pipeline networks are developed to support production and gather product from multiple sites; other networks are developed to move the product to intrastate and interstate markets. All the while, smaller distribution networks are built to take specific advantage of local resources (usually natural gas). In the past, a "network" often meant just a few "farm taps" off of production lines from a single well site.

Colorado's pipeline network followed this organic model and, as elsewhere in the U.S., Front Range pipelines did not begin in earnest until the late 1920's as a strong national market for long-distance natural gas transportation was developing. The discovery of an economic natural gas supply north of Fort Collins, coupled with continuing advances in pipe technology, spurred development. Operators built the first intrastate pipeline from the Wellington field, bringing natural gas to the Denver area. Interstate pipelines followed, and quickly: Colorado Interstate Gas (CIG) began service in early June 1928 with the intent to bring Texas panhandle gas to the Front Range. CIG gas pipelines reached Pueblo in mid-June, and by the end of June were delivering gas to Denver. Segments of those early pipelines still transport gas today.

Colorado's pipeline networks have expanded persistently since those early years, following the demand for petroleum products. Recent increases in oil and gas production from the Denver-Julesburg and Piceance Basins have spurred numerous field (production and gathering) pipelines and a fair number of new long-distance (transmission) pipeline moving oil and gas within, and exporting oil and gas production from, Colorado. Eastern Colorado projects include CIG expansions and the Front Range Pipeline, while the major Piceance-related project was the Rockies Express Pipeline (REX), designed to transport western slope gas to mid-American markets.

As a hydrocarbon-producing state, hydrocarbon pipeline networks in Colorado are naturally abundant. Like many types of infrastructure, these networks developed organically in response to physical and economic growth in the state. Pipeline construction is expected to continue as long as Colorado's economy produces and/or consumes hydrocarbon products.

B. General Regulatory Framework

1. Pipeline Safety

As pipeline networks grew in the 1920's, they made hydrocarbons not only a local resource, but an interstate commodity of increasing national importance. Although some states had made minor inroads into pipeline regulation, it was pipelines' role as a major interstate commodity transport mode that brought them under the jurisdiction of the federal government when, in 1938, the Natural Gas Act (NGA) was passed. NGA provisions were enforced by the Federal Power Commission (FPC), a Federal Energy Regulatory Commission (FERC) precursor that drafted rules regulating interstate gas delivery rates and had the ability to approve/deny new interstate pipelines.

The NGA was an economic act only; it did not include any safety regulation. However, it introduced the concept that pipelines transporting natural gas are vested in the public interest and can therefore be regulated, as well as the concept that transportation of natural gas is distinct from the act of production.

The first Federal statute regulating pipeline safety was the Natural Gas Pipeline Safety Act (the Act) of 1968, which applies to all "pipeline facilities used in the transportation of gas or the treatment of gas during the course of transportation." This means that the Act applies to all pipelines except for production pipelines and rural gathering pipelines.

Congress amended the Act in 1976 and added liquid pipelines to the statute in 1979. Subsequent bills that referenced and enhanced the original Act include the Pipeline Safety Reauthorization Act of 1988, the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002, and two additional Acts in 2006 and 2012.

Concurrent with the Act, Congress created the Office of Pipeline Safety (OPS) in 1968 to oversee and implement pipeline safety regulations. OPS is housed in the U.S. Department of Transportation (DOT), originally under the Research and Special Programs Administration (RSPA) and now under the Pipeline and Hazardous Materials Safety Administration (PHMSA). OPS oversees interstate pipelines while states are responsible for intrastate pipelines. The Hazardous Liquid Pipeline Safety Act of 1979 was enacted on November 30, 1979.

The PHMSA-OPS oversees interstate pipelines. States are responsible for intrastate pipelines, via an interagency agreement with PHMSA. The statutes under which PHMSA operates provide for state assumption of all, or part of, the *intrastate* regulatory and enforcement responsibility through annual "certification agreements." This cooperative, collaborative relationship between federal and state governments forms the cornerstone of our country's pipeline safety program.

Federal statutes and regulations, CFR 49 Parts 190 - 199, prescribe comprehensive *minimum* pipeline safety standards for the pipeline transportation of natural gas and hazardous liquids. According to the Act, states may enact more stringent requirements upon pipeline operators, but cannot waive any minimum requirement without PHMSA approval.

While pipeline safety regulations include requirements for emergency plans, leak detection, and leak response, the bulk of the regulations are meant to prevent releases from jurisdictional pipelines. This is accomplished through the requirement that operators create and adopt explicit procedures that allow for the proper construction, operation, and maintenance of the pipeline.

2. Environmental Protection

Like pipeline safety regulations, current environmental protection regulations have their Federal beginnings in the late 1960s and early 1970s. Particularly relevant to the hydrocarbon pipeline industry are the Clean Water Act, the Clean Air Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, and the Emergency Planning and Community Right-to-Know Act. And, similar to pipeline safety regulations, states may choose to enforce more stringent requirements. None of these are specific to pipelines, but pipeline activities and/or releases from pipelines - both planned and unplanned - may trigger reporting and/or enforcement provisions of these regulations.

Unlike pipeline safety regulations, environmental protection regulations are indifferent to pipeline function (i.e., distribution versus transmission versus gathering versus production), although there are some specific environmental exemptions extended to the hydrocarbon production industry.

3. Oil and Gas Conservation

Many hydrocarbon producing states, including Colorado, have extensive statute and regulation regarding the development of hydrocarbon resources. Since the basic element to oil and gas development is an underlying mineral right, and mineral rights are state-specific, the Federal government does not have overarching authority as with pipeline safety or environmental protection.

Oil and gas conservation agencies are multidisciplinary in function. In addition to regulations, state agencies provide formal and informal guidance, develop field rules, and encourage Best Management Practices. They also conduct field inspections, engage in enforcement/oversight activities, and frequently witness specific operations like well construction, testing and plugging.

4. Other Regulations

Pipeline networks are a unique type of infrastructure in that they can be both local and national. As such, they can be subject to local, state, Federal, and Tribal permitting requirements such as land use, restoration, access, and specialized environmental regulations. In addition to land-use regulations, pipeline construction and operation can be subject to occupational safety regulations.

C. State Regulatory Agencies

The Colorado Public Utilities Commission (COPUC) Gas Pipeline Safety Section is charged with confirming compliance with and enforcing the State's intrastate gas pipeline safety regulations in order to provide public safety to the citizens of Colorado. Nationally, the majority of pipeline inspections are carried out by state inspectors who work for state agencies, generally their Public Utility Commissions or State Fire Marshal offices. The COPUC carries out the inspection and monitoring of intrastate gas pipeline system operators under the review of PHMSA. Regulated pipeline facilities include transmission, distribution, gathering, master metered, liquefied natural gas (LNG), and propane (LPG) gas systems. The COPUC does not have jurisdiction over pipelines not engaged in transport (i.e. pipelines directly associated with gas production, and gas piping within a home or business that is the responsibility of the customer and is regulated by the city or county building codes).

The Colorado Oil and Gas Conservation Commission (COGCC) regulates the production of oil and gas. The mission of COGCC is to foster the responsible development of Colorado's oil and gas natural resources. Responsible development results in the efficient exploration and production of oil and gas resources in a manner consistent with the protection of public health, safety and welfare, prevention of waste, protection of mineral owners' correlative rights, and prevention and mitigation of adverse environmental impacts. COGCC pipeline jurisdiction generally pertains to flowline construction, inspection and integrity along with regulating the reporting of spills, releases or leaks from all flowlines and gathering lines.

The Colorado Department of Public Health and Environment (CDPHE) serves the people of Colorado by providing high-quality, cost-effective public health and environmental protection services. The Department pursues its mission through broad-based health and environmental protection that extends to pipeline operators in the areas of air and water quality, hazardous and solid waste management, pollution prevention, environmental leadership and consumer protection. The mission of the Department is to protect and improve the health of Colorado's people and the quality of its environment.

II. Colorado Regulatory Framework

Relevant regulations covering liquid and natural gas pipelines fall into three principal categories: (1) environmental protection and location, (2) pipeline safety, and (3) worker safety. As described below, portions of these categories fall under the authority of the federal, state, and local governments.

In Colorado, pipelines are regulated to protect public health, safety, and the environment by a host of federal, state, and local agencies

Depending upon the type of product being handled and the location/function of the particular pipeline (e.g., gathering vs. transmission), pipelines and associated facilities are subject to regulation by the following agencies and programs:

- U.S. Environmental Protection Agency (EPA)
- U.S. Dept. of Transportation, Pipeline & Hazardous Materials Safety Admin. (PHMSA)
- U.S. Army Corps of Engineers (USACE)
- U.S. Occupational Safety/Health Admin. (OSHA)
- Colo. Dept. of Public Health & Env't. (CDPHE)
- Colo. Public Utilities Comm'n (COPUC)
- Colo. Oil & Gas Cons. Comm'n (COGCC)
- Colo. Dept. of Labor, Oil & Public Safety (CDOL)
- Utility Notification Center of Colorado (Colorado 811)
- County Commissions and Land Use Review

A. Environmental Regulation (State & Federal)

1. Spill/Release/Leak Reporting and Response

- Prompt reporting of spills/releases/leaks is required to a variety of government agencies, depending upon the type, quantity, and location/affected media of the spill/release:
 - State & local - Release of exploration and production waste (condensate, produced water) > 1 barrel from any source to COGCC, local emergency response, surface owner; release of hazardous wastes to CDPHE and state/local Emergency Planning Committees; other reporting obligations to CDOL; COPUC requires operators of certain natural gas pipelines to report leaks on lines and systems that result in the closure of a roadway, railroad, or an evacuation of 50 or more people.
 - Example release reporting matrices are provided in Appendices B-1 and B-2, delineating how an operator complies with the levels of required reporting to relevant regulatory and emergency response entities.
 - COGCC's Pipeline Release Response Procedure is presented in Appendix C.
 - Federal - releases of hydrocarbon liquids to water or other pollutants above federal Reportable Quantities must be reported to the National Response Center; significant incidents, accidents resulting in explosions or fires, and releases of greater than 5 gallons or more generally must be reported to PHMSA.
 - The PHMSA and COPUC reporting and response process is presented in Appendix D.
- Response obligations are mandated under both state and federal regulations:
 - State requirements and regulations for hydrocarbon releases, commensurate with the applicable state agency (e.g. COPUC or COGCC).
 - Federal requirements and regulations for hydrocarbon releases and releases of other materials (Clean Water Act, Oil Pollution Act, Comprehensive Environmental Response, Compensation, and Liability Act), as well as emergency response training requirements.

2. Air Quality

- Both EPA and CDPHE regulate air emissions associated with certain facilities under the federal Clean Air Act and the Colorado Air Pollution Prevention and Control Act.
 - Direct federal regulation of equipment/activities (EPA):
 - New Source Performance Standards (NSPS) regulate emissions from specific processes and equipment; require emissions control and reduction practices.
 - National Emission Standards for Hazardous Air Pollutants (NESHAP) regulate emissions of HAPs, applying Maximum Achievable Control Technology (MACT) standards.
 - Direct state regulation of equipment/activities in Colorado (CDPHE):
 - Colorado adopts and implements federal regulations such as NSPS and MACT within the state.
 - Emission controls or operation requirements for condensate tanks, glycol dehydrators, pneumatic valves, RICE engines, and flares. Additional controls are now required as part of the new rules adopted by the Air Quality Control Commission in April 2014.

- Colorado has perhaps the most comprehensive, in-depth air quality regulatory regimes for oil and gas facilities in the nation, from low permitting levels, emissions information, and robust direct emissions control regulation of equipment.
 - Reduced Emissions Completions or “green completions” for new wells regulated by both COGCC and CDPHE.
 - In determining a violation of state regulations during a malfunction an operator may establish an affirmative defense if they meet the notification requirements in a timely manner and prove the requirements listed in Appendix E.
 - Notification- The owner or operator of the facility experiencing excess emissions during a malfunction shall notify AQCD verbally as soon as possible, but no later than noon of the Division’s next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source’s next reporting period.
- Air quality construction and operating permits for facilities and equipment.
 - State air permitting requirements govern regulation of “major and minor sources.”
 - Permits incorporate specific state regulatory requirements to reduce air emissions.
 - Impose Reasonably Available Control Technology (RACT) requirements.
 - State-issued Federal Title V Operating Permits apply to “major sources.”
 - Title V permits incorporate all applicable federal regulations to manage and reduce air emissions, and also include monitoring, record keeping, and reporting requirements.
 - State-issued Federal Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NANSR) permits for new/modified “major stationary sources.”
 - Best Available Control Technology (BACT) for attainment areas, and Lowest Achievable Emission Rate (LAER) in non-attainment areas.

3. Water Quality and Waste Management

- Spill containment - Spill Prevention, Control, and Countermeasure (SPCC) plans address spill preparedness, response, containment structures (CDOL).
 - The plans, designed to prevent or contain releases of hydrocarbons, apply to liquids holding tanks in the field, at compressor stations, and at natural gas processing plants.
- Colorado Discharge Permit System (CDPS) permits regulate discharges to surface waters, and the stormwater pollution prevention program mitigates stormwater impacts (CDPHE).
 - Facilities with direct water discharges must hold and comply with CDPS permits, and as applicable hold stormwater plans.
 - Facilities that cross federally owned land, such as national parks or national wildlife refuges, may need to obtain a federal discharge permit under the National Pollutant Discharge Elimination System (NPDES) from the EPA in lieu of a CDPS permit.

- National Pollutant Discharge Elimination System (NPDES) permits regulate discharges to surface waters, and the stormwater pollution prevention program mitigates stormwater impacts (CDPHE).
 - Facilities with direct water discharges must hold and comply with NPDES permits, and as applicable hold stormwater plans.
- Underground Injection Control (UIC wells) regulations and permitting.
 - Manages proper disposal underground of certain appropriate oil and gas hydrocarbon and water wastes pursuant to EPA regulatory requirements.
- Wetlands protection - Clean Water Act § 404 permit requirements govern pipeline construction and facility siting (USACE).
- Landfill disposal requirements and waste management regulations/permitting.

4. Emissions Reporting

Toxic Substances Control Act, the Emergency Planning and Community Right to Know Act, and the Superfund Amendments and Reauthorization Act (Title III) contain requirements for air pollutants, federal greenhouse gas reporting requirements (Subpart W), state/federal release reporting, and state emissions reporting (APEN forms).

B. Location Regulation (Local)

- Local governments exercise land use authority to provide certain regulation on natural gas and petroleum pipelines. It should be noted that regulations vary based on the county; however, the pipeline approval process usually falls into two permitting categories.
 - Special use permit- *May* be subject to approval by the Board of County Commissioners (BCC). If the diameter of the pipeline is less than 10", the hoop stress is less than 20%, and the pipeline is not in proximity to residences or other sensitive areas it is considered, by some counties, a "minor facility". If the pipeline is deemed a minor facility then the permit can be determined administratively, without BCC review, once the pipeline company submits the proper information to the planning commission.
 - Conditional use permit- Must be approved by the Board of County Commissioners. Some counties consider conditional use permits for "major facilities". Pipelines determined to be a "major facility" typically have a diameter greater than 10", a hoop stress greater than 20%, and are in proximity to residences or other sensitive areas. Requirements include notification to adjacent landowners, legal notification in a public newspaper, and a public hearing. Some counties use their authority to identify, designate, and regulate areas and activities of state interest through their local permitting process prior to their decision (commonly referred as 1041 powers).
- Most counties require pipeline companies to submit copies of federal regulators' approval permits, copies of landowner lease agreements, and additional materials.

III. Safety

A. Pipeline Safety

1. General Framework

- Pipeline safety is governed by federal law - Federal statutes and regulations, CFR 49 Parts 190 - 199, prescribe comprehensive pipeline safety standards for the pipeline transportation of natural gas and hazardous liquids.
- Interstate vs. intrastate pipelines, gas vs. liquid - PHMSA has exclusive jurisdiction over all aspects of *interstate* transmission pipeline safety. For *intrastate* natural gas or hazardous liquids transmission and gathering pipelines, jurisdiction may be delegated to the states pursuant to a certification agreement between the U.S. DOT and the state. In Colorado:
 - PHMSA directly regulates all **intrastate** hazardous liquid pipelines (including regulated rural gathering) and all **interstate** natural gas and hazardous liquid pipelines.
 - COPUC regulates all **intrastate** natural gas transmission, distribution, and gathering pipelines, pursuant to CRS § 40-2-115(1.5). COGCC has no jurisdiction over pipeline safety, although it does regulate exploration and production flowlines operated by oil and gas producers from the well to the metering point.
- Federal preemption - Under federal law, states that assume jurisdiction may not adopt additional safety standards that are incompatible with the minimum federal safety standards.

2. Pipeline Safety Regulations

- Federal regulations prescribe comprehensive minimum safety requirements for the transportation of gas and hazardous liquids by pipeline. See 49 CFR Parts 191 and 192 (gas) and Part 195 (hazardous liquids). Specifically, these regulations govern:
 - Pipe materials and design, design of pipeline components, welding and other methods of joining, construction requirements, customer meters and service lines, corrosion control, testing, up rating, operations, maintenance, personnel qualifications, and integrity management.
 - This risk-based regulatory regime recognizes that pipelines located in populated areas, environmentally sensitive areas and High Consequence Areas (HCAs) require more stringent safety standards and practices than pipelines located in largely unpopulated rural areas.
 - As a result of these requirements, transmission pipeline operations are generally remotely monitored and controlled continuously, have extensive leak detection and back-up systems (for example, automate shutdown systems), and conduct regularly-scheduled inspections to monitor internal and external corrosion, third party damage, or construction/manufacturing issues.
 - Gas distribution systems are also subject to risk-based regulations, and operators have distribution integrity management plans that address the major threats to their systems. Most new gas services are installed with an excess flow valve that will shut off the flow of gas if the service is broken.

- State regulations prescribe comprehensive safety requirements for the upstream segment of the pipeline for gas and liquids. See COGCC 1100 Rule Series - Flowline Regulations, Rule 1101. Specifically, these regulations govern:
 - Pipe materials, design, construction requirements, corrosion control, ground cover, excavation, backfill, reclamation, testing, maintenance, repair, and marking.
 - Gathering lines with segments subject to safety regulation by PHMSA must prepare and submit an emergency response plan to the COGCC, the county sheriff, and each local government jurisdiction traversed by such pipeline segment.
- All pipelines are subject to one-call response obligations (see "Colorado 811," below) and environmental regulations.
- The federal 2011 Pipeline Safety Act directed PHMSA to study and make recommendations regarding the existing regulatory framework for gathering pipelines; a rulemaking is anticipated in the near future.
 - Gathering line is defined as:
 - Gas - a pipeline that transports gas from a current production facility to a transmission line or main.
 - Liquid - a pipeline 219.1 mm (8 5/8 in) or less nominal outside diameter that transports petroleum from a production facility.
- For natural gas, Part 192 applies to all transmission pipelines, but is applied differently to the two general classes of gathering pipelines:
 - *Non-rural* gathering pipelines (located in Class 2, 3 and 4 areas; see below) are subject to all transmission pipeline regulatory requirements except integrity management.
 - *Rural* gathering pipelines (located in Class 1 areas) are not regulated under the federal standards, but are subject to the incident-reporting and pipeline marking requirements under COPUC regulations.
 - This classification system for gas gathering pipelines considers (a) the type of material (metallic or non-metallic) and designed pressure rating of the pipe itself, and (b) the "class" location of the pipeline, which is based upon the proximity of the gathering pipeline to buildings intended for human occupancy (class locations range from Class 1 (very rural) to Class 4 (urban)).
 - Note that: Pipeline operators annually survey development activity in and around pipeline locations in order to identify changes in class categories. If development around a rural Class 1 location causes a change in class category, additional safety regulation requirements are triggered.
- For hazardous liquid, Part 195 applies to all non-rural pipelines, but is applied differently to the two general classes of rural pipelines:
 - Regulated rural gathering pipelines meeting all of the following criteria:
 - Diameter from 6.625" to 8.625"
 - Located within ¼ mile of an unusually sensitive area ("USA")
 - Operates above 20% specified minimum yield strength (SMYS)
 - Low stress pipelines: pipelines operating below 20% specified minimum yield strength (SMYS)

- Category 1 (integrity management applies) - located within ½ mile of USA and larger than 8.625" diameter
- Category 2 (integrity management applies) - located within ½ mile of USA (less than 8.625" diameter)
- Category 3 - all other pipelines, no integrity management program (IMP) required

3. High Consequence Areas and Unusually Sensitive Areas

Under both Part 192 and Part 195, PHMSA requires pipeline operators to identify locations along a pipeline route where a pipeline release could have the most significant adverse consequences to human health and safety and the environment. Additional regulatory requirements apply to these areas as part of an operator's integrity management program.

- Gas transmission pipelines - High Consequence Areas (HCAs) are identified solely on the density of population within a certain distance of the pipeline which correlates to the area potentially impacted by a breach or failure. The distance is determined based on the physical and operational characteristics of the pipeline. A large, high pressure pipeline will have a larger area of impact than a smaller, low pressure pipeline.
- Liquid pipelines - HCAs/USAs are identified based upon the proximity of the pipeline to drinking water sources and unusually sensitive ecological resources, and where the pipeline passes through an area of high population density.

4. Colorado 811 - "Call Before You Dig" Regulation

- The primary cause of distribution pipeline safety incidents is excavation damage.
- While pipelines are generally well-marked to prevent damage from digging, and the public can find pipeline location information using the National Pipeline Mapping System, the Colorado 811 program is the primary means by which pipeline accidents can be prevented.
- Colorado 811 is governed by both federal and state law, and is administered by the Utility Notification Center of Colorado (Colorado 811).
- Under State statute, operators/owners of underground facilities, third-party excavators, and the public are obligated to call 811 to submit a utility locate request prior to excavation activities:
 - Obligation to communicate and train the public on hazards associated with underground utilities, and the requirement to "call before you dig" per state law,
 - Obligation of public to call before you dig, and wait three days, and
 - Obligation of utility operators to respond and locate lines within three days.
- Pipeline operators must develop and implement a written continuing public education program that includes provisions to educate the public, appropriate government organizations, and persons engaged in excavation on the use of the Colorado 811 program.
- Pipeline operators must also inspect (via flying, walking, driving or other means) surface conditions on or adjacent to pipeline rights-of-way at regular intervals to ensure the integrity of rights-of-way.

B. Worker Safety

- Process Safety Management (OSHA) (see 29 CFR 1910.119)
 - Unexpected releases of toxic, reactive, or flammable liquids and gases in processes involving highly hazardous chemicals have been reported for various industries that use chemicals with such properties. Regardless of the industry that uses these highly hazardous chemicals, there is a potential for an accidental release any time they are not properly controlled.
 - To help ensure safe and healthful workplaces, OSHA has issued the Process Safety Management of Highly Hazardous Chemicals standard at 29 CFR 1910.119, which contains requirements for the management of hazards associated with processes using highly hazardous chemicals.
 - Process Safety Management (PSM) is addressed in specific standards for the general and construction industries. OSHA's standard emphasizes the management of hazards associated with highly hazardous chemicals and establishes a comprehensive management program that integrates three broad dimensions:
 - Facilities that manufacture and handle hazardous materials,
 - Technology of the processes employed, and
 - Personnel who operate, maintain, and support the process.
 - PSM, for covered midstream gas processing facilities, defines 14 “elements” of PSM that are interlinked and interdependent. Each element either contributes information to other elements for the completion or utilizes information from other elements in order to be completed. These 14 elements include:
 - Process safety information; process hazard analysis; operating procedures; training; contractors; mechanical integrity; hot work; management of change; incident investigation; compliance audits; trade secrets; employee participation; pre-startup safety review; and emergency planning and response.
- Risk Management Plans (EPA-administered, see Clean Air Act Amendments of 1990, § 112(r))
 - The Clean Air Act Amendments of 1990 required the EPA to promulgate regulations and guidance for chemical accident prevention at facilities that use extremely hazardous substances. The Risk Management Plan (RMP) rule builds upon existing industry codes and standards, and requires companies of all sizes that use certain flammable and toxic substances to develop and submit to the EPA an RMP that includes:
 - A hazard assessment that details the potential effects of an accidental release, an accident history of the last five years, and an evaluation of worst-case and alternative accidental releases;
 - A prevention program that includes safety precautions and maintenance, monitoring, and employee training measures; and
 - An emergency response program that spells out emergency health care, employee training measures and procedures for informing the public and response agencies, should an accident occur.
- Equipment and Activity Safety Standards (OSHA)

- Governs construction safety, trenching and shoring, personnel protective equipment, fall protection, hearing protection, hazardous materials training and protection.

IV. Emergency Local Response

Colorado Revised Statute §29-22-102 (1) provides for the designation of emergency response authorities (DERAs) for hazardous substance incidents. Once designated, a DERA is responsible for providing and maintaining the capability for emergency response to a hazardous materials incident occurring within its jurisdiction. A DERA may provide and maintain that capability directly or through mutual aid and other agreements. Under Colorado statute, “emergency response to a hazardous substance incident” means taking the initial emergency action necessary to minimize the effects of a hazardous substance incident. Initial emergency action to minimize the effects ordinarily includes confining, containing, and controlling the product involved.

The identification of a DERA can normally be determined by relying on the following general principles:

- Where a spill or discharge actually occurs will determine the DERA. The location of the events that lead to a spill or discharge is not relevant; the DERA is dependent on the place of spill or discharge
- The Colorado State Patrol is the DERA for spills or discharges that occur within the boundaries of any publicly maintained highway not within a municipality’s corporate limits.
- For spills or discharges that occur within the boundaries of a town, city, or city-county, the fire department is typically the DERA. These local governments will typically designate a DERA by ordinance or resolution. In the absence of action by the local government, the fire department is deemed to be the DERA by default. However, another entity may be designated the DERA by ordinance or resolution. For example, Weld County designated its Office of Emergency Management (OEM). The Weld County OEM coordinates with pipeline operators and first responders in the event of a pipeline incident.
- Except for those spills or discharges that occur within the boundaries of any publicly maintained highway or within the limits of a municipality, the sheriff is typically the DERA. In the absence of such action the county sheriff is the DERA by default. However, another entity may be designated the DERA by ordinance or resolution by the relevant local government.
- Note: By agreement, the Colorado State Patrol is not the DERA for spills or discharges occurring within the boundaries of publicly maintained highways in Arapahoe, Larimer and Mesa Counties.
- Spills or discharges occurring on private property are the responsibility of the property owner, who must either notify the pertinent DERA (municipality or county) and coordinate a response or develop a response independently.

DERAs coordinate with other local emergency response officials to respond to pipeline incidences. Appendix F details two separate incident response scenarios.

V. Agency Contact Information

Bureau of Land Management

[BLM](#)

(303) 236-7991

<http://www.blm.gov>

Colorado Department of Public Health and Safety/Air Quality Control Commission

[CDPHE/AQCC](#)

(303) 692-2000

www.colorado.gov/cdphe

Colorado Emergency Planning Commission

[Local LEPCs](#)

Colorado Fire Protection Association

[Local fire districts](#)

<http://www.cofireprotection.org/contact-fire-districts.html>

Colorado Oil and Gas Conservation Commission

[COGCC](#)

(303) 894-2100

[Local Government Designees](#)

www.colorado.gov/cogcc

Colorado Public Utilities Commission

[COPUC](#)

(303) 894-2854

<http://cdn.colorado.gov/cs/Satellite/DORA-PUC/CBON/DORA/1251614750747>

Colorado State Patrol

[CSP](#)

(303) 239-4501

<http://cdpsweb.state.co.us/>

National Response Center

[NRC](#)

1-800-368-5642

1-800-424-8802

Pipeline and Hazardous Materials Safety Administration

[PHMSA](#)

(202) 366-4433

State Emergency Response Commission

[SERC](#)

Jack Cobb

Colorado Dept. of Public Safety, Office of Emergency Management

(720) 852-6603

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Colorado Dept. of Public Safety, Office of Emergency Management

(720) 852-6611

Greg Stasinos

CDPHE

(303) 692-3023

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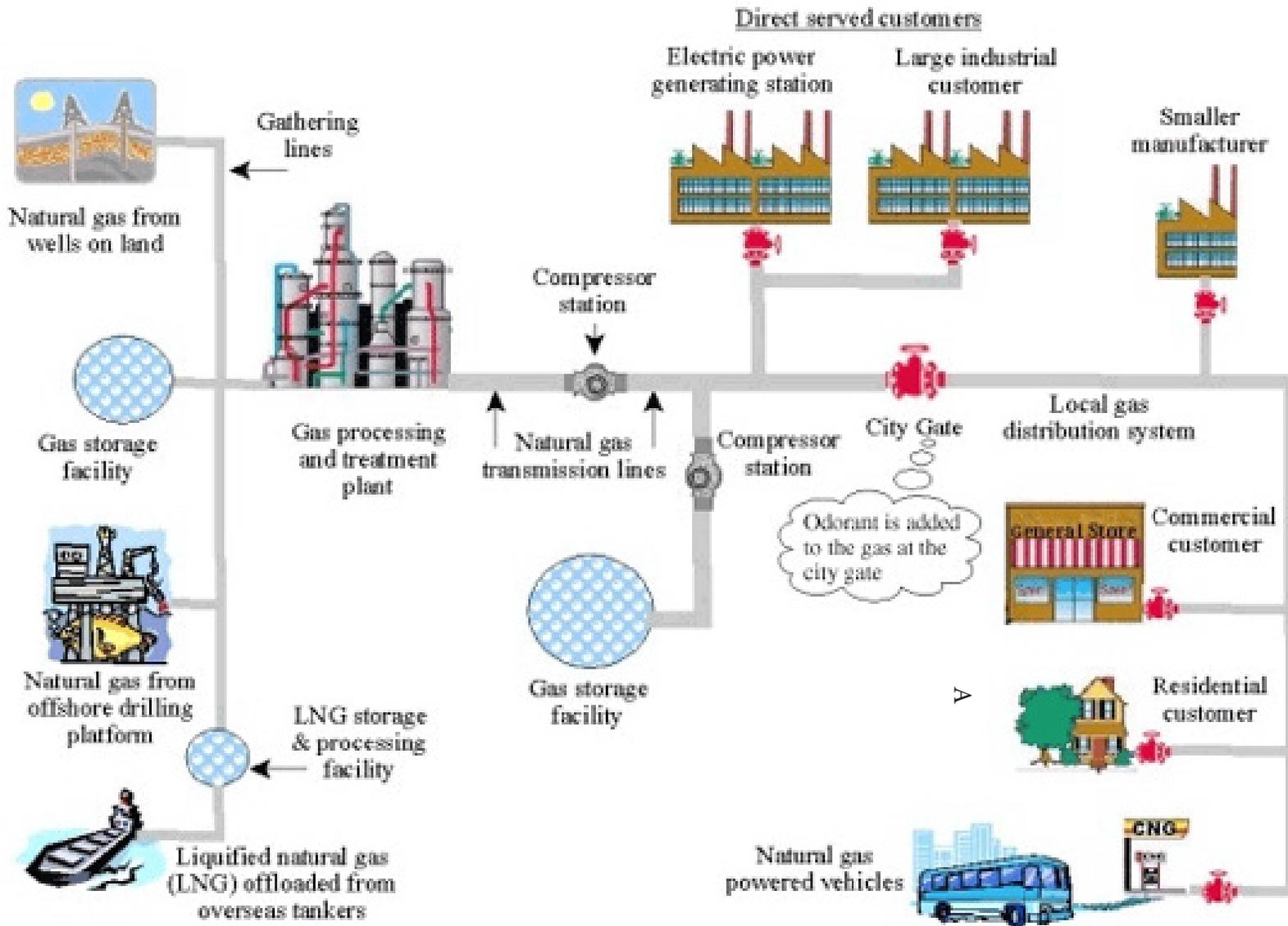
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Air Pollution Control Division Malfunction Requirements

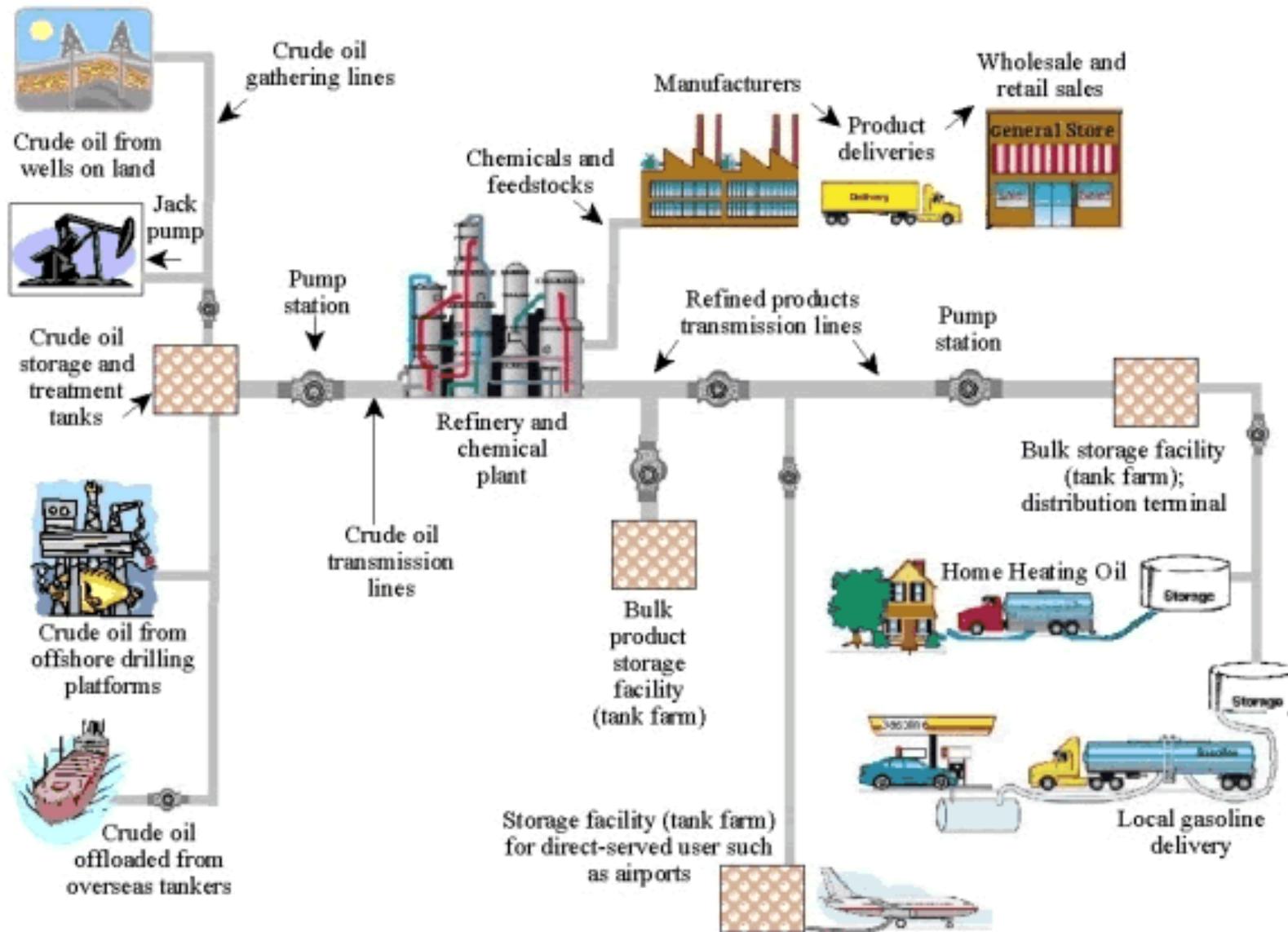
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Local Incident Response Scenarios

Appendix A-1
 Natural Gas Pipeline Systems Visual

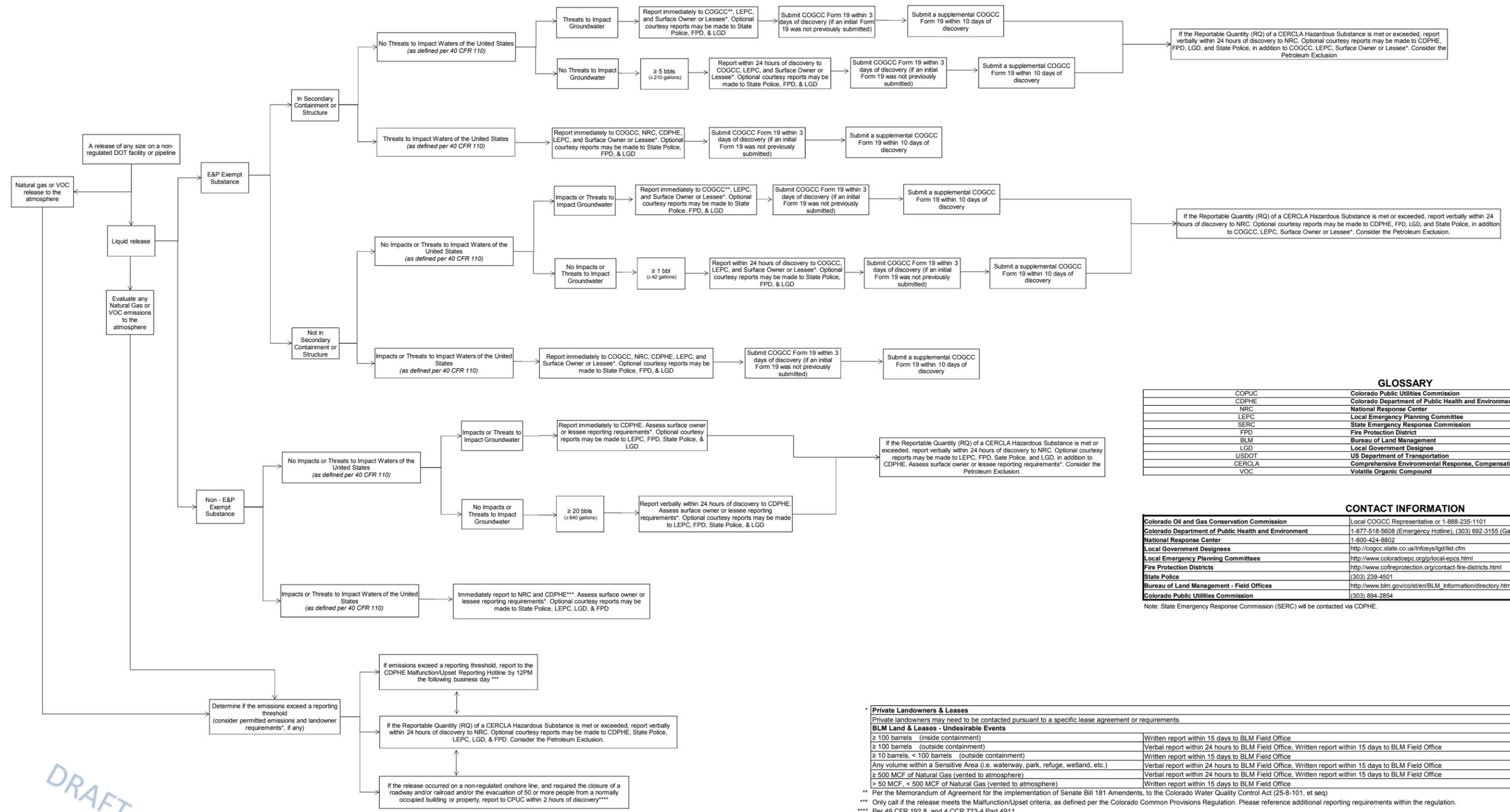


Appendix A-2
Petroleum Pipeline Systems Visual



Sample Colorado Non-USDOT Release Reporting Matrix (Non-Tribal Lands)

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GLOSSARY	
COPUC	Colorado Public Utilities Commission
CDPHE	Colorado Department of Public Health and Environment
NRC	National Response Center
LEPC	Local Emergency Planning Committee
SERC	State Emergency Response Commission
FPD	Fire Protection District
BLM	Bureau of Land Management
LGD	Local Government Designee
USDOT	US Department of Transportation
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
VOC	Volatile Organic Compound

CONTACT INFORMATION	
Colorado Oil and Gas Conservation Commission	Local COGCC Representative or 1-888-235-1101
Colorado Department of Public Health and Environment	1-877-518-5608 (Emergency Hotline), (303) 692-3155 (Gas Release - Malfunction/Upset Hotline)
National Response Center	1-800-424-8802
Local Government Designees	http://cogcc.state.co.us/infosys/igd/list.cfm
Local Emergency Planning Committees	http://www.coloradoepc.org/p/focal-epcs.html
Fire Protection Districts	http://www.fireprotection.org/contact-fire-districts.html
State Police	(303) 239-4501
Bureau of Land Management - Field Offices	http://www.blm.gov/col/st/en/BLM_Information/directory.html
Colorado Public Utilities Commission	(303) 894-2854

Note: State Emergency Response Commission (SERC) will be contacted via CDPHE.

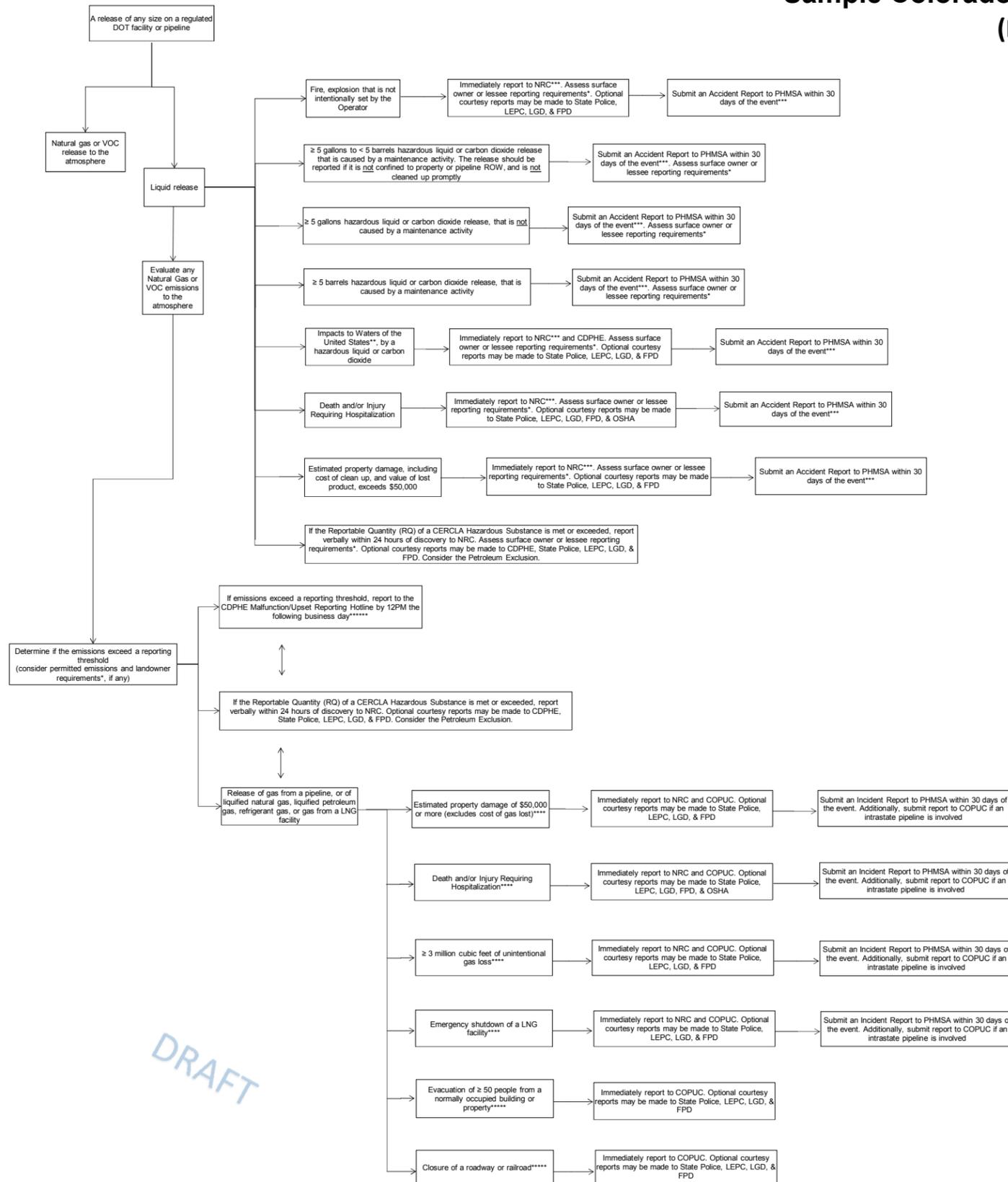
Private Landowners & Leases	
Private landowners may need to be contacted pursuant to a specific lease agreement or requirements.	
BLM Land & Leases - Undesirable Events	
≥ 100 barrels (inside containment)	Written report within 15 days to BLM Field Office
≥ 100 barrels (outside containment)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
≥ 10 barrels, < 100 barrels (outside containment)	Written report within 15 days to BLM Field Office
Any volume within a Sensitive Area (i.e. waterway, park, refuge, wetland, etc.)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
≥ 500 MCF of Natural Gas (vented to atmosphere)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
> 50 MCF, < 500 MCF of Natural Gas (vented to atmosphere)	Written report within 15 days to BLM Field Office

*** Per the Memorandum of Agreement for the implementation of Senate Bill 181 Amendments, to the Colorado Water Quality Control Act (25-8-101, et seq)
**** Per 49 CFR 192.8, and 4 CFR 723-4 Part 4911.

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Sample Colorado USDOT Release Reporting Matrix (Non-Tribal Lands)

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GLOSSARY

COPUC	Colorado Public Utilities Commission
USDOT	US Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
NRC	National Response Center
OSHA	Occupational Safety & Health Administration
LEPC	Local Emergency Planning Committee
SERC	State Emergency Response Commission
FPD	Fire Protection District
BLM	Bureau of Land Management
LGD	Local Government Designee
PHMSA	Pipeline Hazardous Materials Safety Administration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
LNG	Liquefied Natural Gas
VOC	Volatile Organic Compound

CONTACT INFORMATION

Colorado Public Utilities Commission	(303) 894-2854
Colorado Department of Public Health and Environment	1-877-518-5608 (Emergency Hotline), (303) 692-3155 (Gas Release - Malfunction/Upset Hotline)
National Response Center	1-800-424-8802
Occupational Safety & Health Administration	(303) 844-1600, (720) 264-6550
Local Emergency Planning Committees	http://www.coloradoepc.org/local-epcs.html
Fire Protection Districts	http://www.cofireprotection.org/contact-fire-districts.html
State Police	(303) 239-4501
Bureau of Land Management - Field Offices	http://www.blm.gov/col/st/en/BLM_Information/directory.html
Local Government Designees	http://cogcc.state.co.us/info/sylgd/list.cfm

Note: State Emergency Response Commission (SERC) will be contacted via CDPHE.

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* Private Landowners & Leases	
Private landowners may need to be contacted pursuant to a specific lease agreement or requirements.	
BLM Land & Leases - Undesirable Events	
≥ 100 barrels (inside containment)	Written report within 15 days to BLM Field Office
≥ 100 barrels (outside containment)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
≥ 10 barrels, < 100 barrels (outside containment)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
Any volume within a Sensitive Area (i.e. waterway, park, refuge, wetland, etc.)	Verbal report within 24 hours to BLM Field Office
≥ 500 MCF of Natural Gas (vented to atmosphere)	Verbal report within 24 hours to BLM Field Office, Written report within 15 days to BLM Field Office
> 50 MCF, < 500 MCF of Natural Gas (vented to atmosphere)	Written report within 15 days to BLM Field Office

** As defined per 40 CFR 110
 *** As defined per 49 CFR 195
 **** As defined per 49 CFR 191
 ***** As defined per 4 CCR 723-4 Part 4911
 ***** Only call if the release meets the Malfunction/Upset criteria, as defined per the Colorado Common Provisions Regulation. Please reference additional reporting requirements within the regulation.

Appendix C

COGCC Pipeline Release Response Procedure

COGCC Pipeline Release Response Procedure

When COGCC is notified of a reportable release associated with a pipeline the following procedures are followed similar to other reportable spill reports received:

1. COGCC requests the operator submit a Form 19 within the appropriate reporting period in accordance with Rule 906.b.
2. COGCC verifies with the reporting party that the source of the spill has been stopped – that the source has been terminated or the leaking line segment has been isolated.
3. If the source has not been stopped, COGCC verifies that emergency response measures are in progress to control the release.
4. COGCC makes preliminary determination with reporting party if groundwater, domestic water wells or surface water have been impacted or threatened.
5. COGCC verifies that all appropriate parties have been notified – surface owner, CDPHE, NRC, local government.
6. COGCC field staff will respond as needed to document spill conditions and provide regulatory oversight.
7. If not already performed, COGCC directs operator to expose leaking segment of line, and when safe, to remove all subsurface impacts.
8. After source material surrounding the release has been removed, COGCC requires the operator collect confirmation soil samples, and if appropriate, groundwater samples to verify compliance with Table 910-1 standards in accordance with Rule 909 Site Investigation, Remediation and Closure requirements.
9. If release was limited in extent, no groundwater or surface water were impacted and contaminated soil is easily removed and properly treated or disposed, COGCC will request supporting closure documentation and close the Spill Report.
10. If release was extensive requiring significant follow-on remediation or if groundwater or surface water were impacted by release, COGCC will request a Form 27 Site Investigation and Remediation Workplan.
11. In either case (8 or 9), COGCC will request documentation that verifies compliance with Table 910-1 standards for affected media and waste disposal documentation prior to final closure.
12. COGCC requires that any resulting surface damage be properly reclaimed in accordance with the 1000 Series Reclamation Regulations or that surface improvements are repaired to pre-existing conditions.
13. COGCC may request documentation that the operator was in compliance with Rule 1101.e. regarding pressure testing of flowlines. COGCC may also request verification that the repaired line or replaced line meets pressure testing requirements prior to return to service.
14. COGCC field staff will respond as needed to verify that remediation and surface reclamation were performed as reported.

Appendix D

PHMSA/COPUC Pipeline Accident/Incident Reporting Processes

PHMSA/COPUC Pipeline Accident/Incident Reporting Processes:

1. Telephonic Reporting incidents/accidents.

“Incident” is defined by PHMSA as a release of gas and resulting in: death, injury, property damage > \$50,000, or an unintentional release of gas loss of > three million cubic feet.

“Accident” is defined by PHMSA as a failure resulting in the release of a hazardous liquid or carbon dioxide and resulting in: explosion or fire, death, injury, property damage including clean up and recovery > \$50,000, release of > 5 gallons outside of company property or pipeline right-of-way or a release not cleaned up promptly, or results in the pollution of a stream/body of water.

- National pipeline safety regulations require transportation pipeline operators of natural gas and hazardous liquid to report any Incident (gas) or Accident (liquid) to the National Response Center of the Department of Transportation (NRC). An incident and accident telephonic report is defined within its respective code (49 CFR 192/195).
- The NRC automatically forwards the reported information to all federal and state agencies who have registered to receive that information. Individual agencies will initiate a response based on their statutory authority/mission.
- PHMSA responds to an accident occurring on a hazardous liquid pipeline and interstate gas pipeline incidents.
- The COPUC responds to an intrastate gas pipeline incident and also requires intrastate gas operators to report certain “events” when a gas leak occurs on a gas pipeline. A reportable COPUC “Event” occurs when there is a release of gas and an evacuation of \geq 50 people from a normally occupied building, the closure of a roadway or railroad, or when an evacuation of a master metered gas system such as a trailer park occurs.
- Unless specific reasons warrant, an inspector will respond to an incident/accident when any death, injury, or explosion related to natural gas facility occurs. An investigation is initiated with the primary goal of determining if a violation of 49 CFR Parts 192 or 195 occurred.

2. Written Reports:

A written report is required to be submitted to PHMSA within 30 days of an accident or incident. COPUC also requires a copy of the PHMSA report when an intrastate natural gas pipeline is involved.

Appendix E

Air Pollution Control Division Malfunction Requirements

Air Pollution Control Division Malfunction Requirements

1. The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;
2. The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;
3. Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded.
4. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;
5. All Reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;
6. All emissions monitoring systems were kept in operation (if at all possible);
7. The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;
8. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;
9. At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This Section II.E.1.i. of the Common Provisions is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and
10. During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

Appendix F

Local Incident Response Scenarios

Local Incident Response Scenarios

1. General Local Hazmat Spill Response Process

A spill occurs and local governments ask the follow questions:

1. Who is responding to the spill? Dispatch sends appropriate resources to scene.
2. Are they capable of handling the response?
3. What jurisdiction is the spill located in?
4. Who is the DERA for this incident?

Local governments assess the scene, what may have spilled and how much:

1. Identification of the product spilled, how much has leaked and how much is left?
2. Try to stop leak and/or contain the spill.
3. Is it close to a water way or water intake? If so, notify downstream water users.
4. Contact County, State, EPA, Coast Guard (water ways), Public Health, Sheriff, COGCC
5. Identify property ownership.
6. Who spilled the product? Are they willing to clean it up?
7. DERA contacts third-party company for clean up, if entity responsible for the spill doesn't have someone they use or are not willing to clean it up. If no one can be identified as responsible for the spill, it is the DERA's responsibility to get it cleaned up.
8. Once the clean up has started, DERA monitors the progress to make sure it is being cleaned up correctly and efficiently.
9. Contact BOCC, State or City Council about the amount of funds needed to complete clean up.

2. Pipeline Incident Scenario

March 19, 2014, 1700 Hrs, a call into police dispatch center indicating a natural gas gathering line was hit by a company drilling in the area and gas is venting. The area is rural, agricultural, with other Oil and Gas facilities in the area. There are several homes within $\frac{3}{4}$ of a mile.

The local fire department has been dispatched to the call and is enroute. The Sheriff's Office is notified of the call. Once the Fire Department gets on scene they set up incident command and are working to identify the gas line that was hit to get it shut down. While talking with the drilling company that hit the line, the Fire Department is advised that according to locate information there should not be any pipelines in the area.

At 1715 the Sheriff's Office is requested to help with road blocks in the area due to the gas line that is still venting. One of the Captains with the Sheriff's Office hears the call and contacts Dispatch by phone and gets the information on the original call, the Captain issues an evacuation reverse 9-1-1 for the area. Deputies set up road blocks at intersections one mile away from the location of the leak.

1720 hrs, the Fire Department is working to have local Gas Operators included with incident command but they are having trouble getting through the road blocks.

At 1730 the gas line is shut down and was identified as an old line that had not been mapped but was still active.

Questions to improve incident response:

How do local governments improve coordination of First Responders and industry in incident command?

How do local governments improve access of industry partners past roadblocks, and communicate this to First Responders?

How do local governments help responders understand the risk associated with gas leaks, as they determine a response of community evacuation vs shelter in place? How do local governments communicate this to citizens and help First Responders understand the process?