

GENERAL INSTRUCTIONS

Each operator of a gas transmission or gathering pipeline system shall file Form PHMSA F 7100.2 for an incident that meets the criteria in 49 CFR §191.3 as soon as practicable but not more than 30 days after detection of the incident. Requirements for submitting reports are in §191.7 and §191.15.

The intentional and controlled release of gas for the purpose of maintenance or other routine operating activities is not to be reported. Reports are required if the loss of gas unintentionally released is 3 million cubic feet or more.

Special considerations apply when a pipeline failure or release occurs involving secondary ignition. Secondary ignition is a fire where the origin of the fire is unrelated to the gas systems subject to Parts 191 or 192, such as electrical fires, arson, etc., and includes events where fire or explosion not originating from a pipeline system failure or release was the primary *cause* of the pipeline system failure or release, such as a refinery fire that subsequently resulted in – but was not caused by – a gas transmission or gas gathering pipeline system failure or release. An event caused by secondary ignition is not to be reported unless a release of gas escaping from facilities subject to regulation under Parts 191 or 192 results in one or more of the consequences as described in §191.3 under "Incident" (1). The determination of consequences from a pipeline incident caused by secondary ignition, though, is an area of possible confusion when reporting incidents. PHMSA is providing the following guidance for operators to use when secondary ignition is involved (sometimes referred to as “Fire First” incidents):

- A pipeline incident attributed to secondary ignition is to be reported to PHMSA if any fatalities or injuries are involved unless it can be established with reasonable certainty that all of the casualties either preceded the pipeline system failure or release, or would have occurred whether or not the pipeline system failure or release occurred.
- A pipeline incident attributed to secondary ignition is NOT to be reported to PHMSA if the only reportable criterion is unintentional loss of gas of 3 million cubic feet or more as described in §191.3 under "Incident" (1)(iii).
- A pipeline incident attributed to secondary ignition is NOT to be reported to PHMSA unless the damage to facilities subject to Parts 191 or 192 equals or exceeds \$50,000.

These considerations apply to several pipeline incident cause categories as indicated in pertinent sections of these instructions.

Form PHMSA F 7100.2 and these instructions can be found on <http://phmsa.dot.gov/pipeline/library/forms>. The applicable documents are listed in the section titled Accident/Incident/Annual Reporting Forms.

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ONLINE REPORTING REQUIREMENTS

Incident Reports must be submitted online through the PHMSA Portal at <https://portal.phmsa.dot.gov/portal>, unless an alternate method is approved (see Alternate Reporting Methods below). You will not be able to submit reports until you have met all of the Portal registration requirements – see

http://opsweb.phmsa.dot.gov/portal_message/PHMSA_Portal_Registration.pdf

Completing these registration requirements could take several weeks. Plan ahead and register well in advance of the report due date.

Use the following procedure for online reporting:

1. Go to the PHMSA Portal at <https://portal.phmsa.dot.gov/portal>
2. Enter PHMSA Portal Username and Password ; press *enter*
3. Select OPID; press “*continue*” button.
4. On the left side menu under “Incident/Accident (2010 to present)” select “**ODES 2.0**”
5. Under “**Create Reports**” on the left side of the screen, select “Gas Transmission and Gathering” and proceed with entering your data.
6. Click “**Submit**” when finished with your data entry to have your report uploaded to PHMSA’s database as an official submission of an Incident Report; or click “**Save**” which doesn’t submit the report to PHMSA but stores it in a draft status to allow you to come back to complete your data entry and report submission at a later time. *Note: The “Save” feature will allow you to start a report and save a draft of it which you can print out and/or save as a PDF to email to colleagues in order to gather additional information and then come back to accurately complete your data entry before submitting it to PHMSA.*
7. Once you click “**Submit**”, the system will check if all applicable portions of the report have been completed. If portions are incomplete, a listing of these portions will appear above the row of Parts. If all applicable portions have been completed, the system will show your Saved Incident/Accident Reports in the top portion of the screen and your Submitted Incident/Accident Reports in the bottom portion of the screen. *Note: To confirm that your report was successfully submitted to PHMSA, look for it in the bottom portion of the screen where you can also view a PDF of what you submitted.*

Supplemental Report Filing – Follow Steps 1 through 4 above, and then double-click a submitted report from the Submitted Incident/Accident Reports list. The report will default to a “Read Only” mode that is pre-populated with the data you submitted previously. To create a supplemental report, click on “Create Supplemental” found in the upper right corner of the screen. At this point, you can amend your data and make an official submission of the report to PHMSA as either a Supplemental Report or as a Supplemental Report *plus* Final Report (see “Specific Instructions, PART

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A, Report Type”), or you can use the “**Save**” feature to create a draft of your Supplemental Report to be submitted at some future date.

Alternate Reporting Methods

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternate reporting method. Operators must follow the requirements in §191.7(d) to request an alternate reporting method and must comply with any conditions imposed as part of PHMSA’s approval of an alternate reporting method.

RETRACTING A 30-DAY WRITTEN REPORT

An operator who reports an incident in accordance with §191.15 (oftentimes referred to as a 30-day written report) and upon subsequent investigation determines that the event did not meet the criteria in §191.3 may request that the report be retracted. Requests to retract a 30-day written report are to be emailed to InformationResourcesManager@dot.gov. Requests are to include the following information:

- a. The Report ID (the unique 8-digit identifier assigned by PHMSA)
- b. Operator name
- c. PHMSA-issued OPID number
- d. The number assigned by the National Response Center (NRC) when an immediate notice was made in accordance with §191.5. If Supplemental Reports were made to the NRC for the event, list all NRC report numbers associated with the event.
- e. Date of the event
- f. Location of the event
- g. A brief statement as to why the report should be retracted.

Note: PHMSA no longer requests that operators rescind erroneously reported “Immediate Notices” filed with the NRC in accordance with §191.5 (oftentimes referred to as “Telephonic Reports”).

SPECIAL INSTRUCTIONS

Certain data fields must be completed before an Original Report will be accepted. Your Original Report will not be able to be submitted online until the required information has been provided, although your partially completed form can be saved online so that you can return at a later time to provide the missing information.

1. An entry should be made in each applicable space or check box, unless otherwise directed by the section instructions.
2. If the data is unavailable, enter “Unknown” for text fields and leave numeric fields and fields using check boxes or “radio” buttons blank.
3. Estimate data only if necessary. Provide an estimate in lieu of answering a question with “Unknown” or leaving the field blank. Estimates should be based on best-available information and reasonable effort.
4. For unknown or estimated data entries, the operator should file a Supplemental Report when additional or more accurate information becomes available.
5. If the question is not applicable, enter “N/A” for text fields and leave numeric fields and fields using check boxes or “radio” buttons blank. Do not enter zero unless this is the actual value being submitted for the data in question.
6. If **OTHER** is checked for any answer to a question, include an explanation or description on the line provided, making it clear why “Other” was the necessary selection.
7. Pay close attention to each question for the phrase:
 - a. *(select all that apply)*
 - b. *(select only one)*

If the phrase is not provided for a given question, then “select only one” should apply. “Select only one” means that you should select the single, primary, or most applicable answer. **DO NOT SELECT MORE ANSWERS THAN REQUESTED.** “Select all that apply” requires that all applicable answers (one or more than one) be selected.

8. **Date format** = mm/dd/yy or for year = /yyyy/
9. **Time format:** All times are reported as a 24-hour clock:
Time format Examples:
 - a. (0000) = midnight = /0/0/0/0/
 - b. (0800) = 8:00 a.m. = /0/8/0/0/
 - c. (1200) = Noon = /1/2/0/0/
 - d. (1715) = 5:15 p.m. = /1/7/1/5/
 - e. (2200) = 10:00 p.m. = /2/2/0/0/

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Local time always refers to time at the site of the incident. Note that time zones at the incident site may be different than the time zone for the person discovering or reporting the event. For example, if a release occurs at an gas transmission facility in Denver, Colorado at 2:00 pm MST, but an individual located in Houston is filing the report after having been notified at 3:00 pm CST, the time of the incident is to be reported as 1400 hours based on the time in Denver, which is the physical site of the incident.

PART A – KEY REPORT INFORMATION

Report Type: (select all that apply)

Select the appropriate report box or boxes to indicate the type of report being filed. Depending on the descriptions below, the following combinations of boxes – and only one of these combinations - may be selected:

- Original Report only
- Original Report *plus* Final Report
- Supplemental Report only
- Supplemental Report *plus* Final Report

Original Report

Select if this is the FIRST report filed for this incident and you expect that additional or updated information will be provided later.

Original Report *plus* **Final Report**

Select **both** Original Report and Final Report if ALL of the information requested is known and can be provided at the time the initial report is filed, including final property damage costs and apparent failure cause information. If new, updated, and/or corrected information becomes available, you are still able to file a Supplemental Report.

Supplemental Report

Select only if you have already filed an Original Report AND you are now providing new, updated, and/or corrected information. Multiple Supplemental Reports are to be submitted, as necessary, in order to provide new, updated, and/or corrected information ***when it becomes available*** and, per §191.15(c), each Supplemental Report containing new, updated, and/or corrected information is to be filed as soon as practicable. Submission of new, updated, and/or corrected information is NOT to be delayed in order to accumulate “enough” to “warrant” a Supplemental Report, or to complete a Final Report. ***Supplemental Reports must be filed as soon as practicable following the Operator’s awareness of new, updated, and/or corrected information.*** Failure to comply with these requirements can result in enforcement actions, including the assessment of civil penalties as provided in 49 USC 60122.

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For Supplemental Reports filed online, all data previously submitted will automatically populate in the form. Page through the form to make edits and additions where needed.

Supplemental Report *plus* **Final Report**

If an Original Report has already been filed AND new, updated, and/or corrected information is now being submitted via a Supplemental Report AND the operator is reasonably certain that no further information will be forthcoming, then Final Report is to also be selected along with Supplemental Report. If you subsequently find that new, updated, and/or corrected information needs to be provided, submit another Supplemental Report.

A1. Operator’s OPS -Issued Operator Identification Number (OPID)

For online entries, the OPID will automatically populate based on the selection you made when entering the Portal. If you have log-in credentials for multiple OPID, be sure the report is being created for the appropriate OPID. Contact PHMSA’s Information Resources Manager at 202-366-8075 if you need assistance with an OPID. Business hours are 8:30 AM to 5:00 PM Eastern Time.

A2. Name of Operator

This is the company name associated with the OPID. For online entries, the name will automatically populate based on the OPID entered in A1. If the name that appears is not correct, you need to submit an Operator Name Change (Type A) Notification.

A3. Address of Operator

For online entries, the headquarters address will automatically populate based on the OPID entered in A1. If the address that appears is not correct, you need to change it in the online Contacts module.

A4. Earliest local time (24-hour clock) and date an incident reporting criteria was met

Enter the earliest local date/time an incident reporting criteria was met. In some cases, this date/time must be estimated based on information gathered during the investigation.

See “Special Instructions”, numbers 8 and 9 for examples of **Date format** and **Time format** expressed as a 24-hour clock.

A4a. Select the local time zone where the Incident occurred (select only one).

A4b. Select “Yes” if Daylight Saving was in effect at the time of the Incident, or “No” if it was not.

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A5. Location of Incident

The latitude and longitude of the incident are to be reported as Decimal Degrees with a minimum of 5 decimal places (e.g. Lat: 38.89664 Long: -77.04327), using the NAD83 or WGS84 datums.

If you have coordinates in degrees/minutes or degrees/minutes/seconds, use the formula below to convert to decimal degrees:

$$\text{degrees} + (\text{minutes}/60) + (\text{seconds}/3600) = \text{decimal degrees}$$

e.g. $38^{\circ} 53' 47.904'' = 38 + (53/60) + (47.904/3600) = 38.89664^{\circ}$

All locations in the United States will have a negative longitude coordinate, **which has already been included on the data entry form so that operators do not have to enter the negative sign.**

If you cannot locate the incident with a GPS or some other means, there are online tools that may assist you at <http://viewer.nationalmap.gov/viewer/>. Any questions regarding the required format, conversion, or how to use the tools noted above can be directed to Amy Nelson (202-493-0591 or amy.nelson@dot.gov).

A6. Gas released

Select the type of gas released. An example of **Synthetic Gas** is manufactured gas based on naphtha. **Landfill Gas** includes biogas.

Important Note for Questions 7, 8, and 9: Volumes consumed by fire and/or explosion are to be included in the estimated volumes reported.

A7. Estimated volume of gas released unintentionally

Estimate the amount of gas that was released (in thousands of standard cubic feet, mcf) from the beginning of the incident until such time as gas is no longer being released from the pipeline system or until intentional and controlled blowdown has commenced. Estimates are to be based on best-available information. *Important Note: Volumes consumed by fire and/or explosion are to be included in the estimated volume reported.*

The volumes released during an Emergency Shutdown (ESDs) or relief valve activation should be reported. When ESDs or relief valves are activated as the result of a safety condition that has occurred, the volume released should be included in the “unintentional” category, even if safety equipment performed as designed (such as a power loss or upon a PLC command). This would include when an employee intentionally activates the ESD in response to an unintentional safety condition, such as a grass fire in the station yard.

A8. Estimated volume of intentional and controlled release/blowdown

Estimate the amount of gas that was released (in thousands of standard cubic feet, mcf) during any intentional release or controlled blowdown conducted as part of responding to or recovering from

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the incident. Intentional and controlled blowdown implies a level of control of the site and situation by the operator such that the area and the public are protected during the controlled release. Occasionally actions associated with response to an incident can involve activation of the Emergency Shutdown (ESD) and associated relief equipment that occurs on a planned maintenance basis after the incident initial safety response and the area has been evaluated for damage. For example, an engine crankcase explosion has occurred and only one compressor in the area is damaged. The immediate unintentional release was to activate the blowdown equipment associated with this engine only. However, upon reviewing the damage, it was determined that the ESD system should be activated for an entire station as more than one engine’s systems were affected by the incident. The volume of intentional ESD release or associated relief devices that has occurred after the evaluation in anticipation for the repairs should be included in the “intentional” volume released.

A9. Estimated volume of accompanying liquid released

Estimate the amount of accompanying liquid that was spilled to the ground (or other containment) as a liquid (in barrels) from the beginning of the incident until such time as the liquid is no longer being released from the system. Barrel means a unit of measurement equal to 42 U.S. standard gallons. If less than 1 barrel, report to 1 decimal place using the conversion table below. Small volumes, including but not limited to those which sometimes result in some form of ignition, are to be reported as 0.1 barrels.

If estimated volume is	Report	If estimated volume is	Report
<5 gallons	0.1 barrels	24-27 gallons	0.6 barrels
5-10 gallons	0.2 barrels	28-31 gallons	0.7 barrels
11-14 gallons	0.3 barrels	32-35 gallons	0.8 barrels
15-18 gallons	0.4 barrels	36-39 gallons	0.9 barrels
19-23 gallons	0.5 barrels	40-42 gallons	1.0 barrels

A10. Were there fatalities?

If a person dies at the time of the incident or within 30 days of the initial incident date due to injuries sustained as a result of the incident, report as a fatality. If a person dies subsequent to an injury more than 30 days past the incident date, report as an injury. (Note: This aligns with the Department of Transportation's general guidelines for all jurisdictional transportation modes for reporting deaths and injuries.)

Select “Yes” or “No” and if “Yes” is selected, enter the category of person(s) and number of fatalities resulting from the Incident.

Contractor employees working for the operator are individuals hired to work for or on behalf of the operator of the pipeline. These individuals are not to be reported as “Operator employees”.

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Non-Operator emergency responders are individuals responding to render professional aid at the incident scene, including on-duty and volunteer fire fighters, rescue workers, EMTs, police officers, etc. “Good Samaritans” that stop to assist are to be reported as “General public.”

Workers Working on the Right-of-Way, but NOT Associated with this Operator means people authorized to work in or near the right-of-way, but not hired by or working on behalf of the operator of the pipeline. This includes all work conducted within the right-of-way including work associated with other underground facilities sharing the right-of-way, building/road construction in or across the right-of-way, or farming. This category most often includes employees of other pipelines or underground facilities operators, or their contractors, working in or near a shared right-of-way. Workers performing work near, but not on, the right-of-way and who are affected are to be reported as “General public”.

A11. Were there injuries requiring inpatient hospitalization?

Injuries requiring inpatient hospitalization are injuries sustained as a result of the incident and that require both hospital admission *and* at least one overnight stay.

Select “Yes” or “No” and if “Yes” is selected, enter the category of person(s) and number of fatalities resulting from the Incident.

See Question A10 for additional definitions that apply.

A12. What was the Operator’s initial indication of the Failure? (*select only one*)

Select the best option to describe the manner in which the operator initially identified the failure resulting in this reported Incident.

Controller means a qualified individual whose function within a shift is to remotely monitor and/or control the operations of entire or multiple sections of pipeline systems via a SCADA system from a pipeline control room, and who has operational authority and accountability for the daily remote operational functions of pipeline systems.

Local Operating Personnel including contractors means employees or contractors working on behalf of the operator outside the control room.

A12a. If the Incident was identified by Operator’s personnel or a contractor working for the Operator (including controller, air and ground patrols) in A12, identify if it was by an Operator employee, or a contractor working for the Operator.

A13. When did the operator identify the failure?

Enter the date/time of the operator’s initial indication of the failure. The earliest date/time that an incident reporting criteria was met is reported in item A4. In some cases, the operator may become aware of a failure before an incident reporting criteria is met. In other cases, one or more incident reporting criteria may be met before the operator becomes aware of the failure.

A14. What part of the system was involved in the Incident?

Select the best description of the part of the system that was involved in the Incident. Only one selection may be made.

A15. What was the operational status of the pipeline at the time the failure was identified?

Select the best description of the operating status of the pipeline system at the date/time reported in A4.

Post-Construction Commissioning means the introduction of product, testing and commissioning of the pipeline prior to the start of commercial operations.

Post-Maintenance/Repair means purging and packing of the pipeline when returning it to service from maintenance or repairs.

Routine Start-Up means the start-up of the pipeline, facility or system in normal operations, or returning from maintenance or other idle status following a time of no flow, but the where the pipeline remained liquid full, and the start-up was being conducted under normal start-up procedures.

Routine Shutdown means the stoppage of equipment or the system from a normal operation status.

Normal Operation, include pauses during maintenance means the pipeline is operating normally, and any of the maintenance that is occurring does not require product to be removed from the pipeline or system. Product sampling, inhibitor injection, in-line inspection, installation of repairs, and other activities covered by the operator's Operation and Maintenance Procedures are examples of the maintenance included in this category.

Idle means that the pipeline has been removed from service for commercial reasons or to make repairs. The pipeline may contain product, an inert gas, or be empty. When residual product accumulates in an excavation and ignites, Idle is the proper status.

A16. Was the pipeline/facility shut down due to the Incident?

If A15. is Routine Start-Up or Normal Operations, indicate if shutdown occurred as a result of the incident, including but not limited to those required for damage assessment, temporary repair, permanent repair, and clean-up. Do not include equipment shutdowns that do not affect the pipeline or system operation. For example, if a compressor shutdown occurred as part of the incident, but the pipeline was able to continue operating, select No. If No is selected, explain the reason that no shutdown was needed in the space provided. A possible explanation for the example above would be "The pipeline continued to operate through the station bypass piping and did not require a pipeline shutdown."

If Yes is selected, complete Questions 16a and 16b.

16a. Local time (24hr clock) and date of shutdown

16b. Local time pipeline/facility restarted

The time is to be shown by 24-hour clock notation, and is to reflect the time in the time zone where the incident was physically located. (See “Special Instructions”, numbers 9 and 10.) Enter the time and date the pipeline was isolated or equipment stopped in 16a. The affected facilities may still contain gas at this time. Enter the time and date of restart in 16b. The intent with this data is to capture the total time that the pipeline or facility is shutdown due to the incident. If the pipeline or facility has not been restarted, select “Still shut down” for Question 15b and then include the restart time and date in a future Supplemental Report.

A17. Operator Communication with Local, State, or Federal Emergency Responders

In an Advisory Bulletin dated October 11, 2012, PHMSA reminded Operators of the need to communicate with Emergency Responders in the early stages of a potential Incident. This is typically accomplished by contacting Public Safety Access Points (PSAPs) along the pipeline route. The purpose of the communication is to assist in the identification, location, and planning for response to pipeline Incidents through coordination and information sharing.

A17a. Select Yes if there was communication about the incident. If A12. is “Notification from Emergency Responder”, A17a. will automatically populate with Yes.

If 17a. is no, skip 17b. and 17c.

A17b. Select the party initiating the communication. If A12. is “Notification from Emergency Responder”, A17b. will automatically populate with “Local/State/Federal Emergency Responder”.

A17c. Enter the local date and time of the initial communication. If A12. is “Notification from Emergency Responder”, A17c. will automatically populate with the value in A13.

A18. What time did Operator resources arrive on site?

Enter the date/time operator responders, company or contract, arrived on site. The time is to be shown by 24-hour clock notation and reported in the time zone where the incident occurred. (See “Special Instructions”, numbers 8 and 9.) PHMSA will use this data to calculate incident response times.

A19. reserved

A20a. Local time (24-hr clock) and date of initial operator report to the National Response Center

Enter the time and date of the initial Immediate Notice of the incident to the NRC. The time is to be shown by 24-hour clock notation in the time zone where the incident occurred. All NRC reports are time stamped for the eastern time zone. Be sure to convert to local time if the incident did not occur in the eastern time zone. (See “Special Instructions”, numbers 9 and 10.)

A20b. Initial Operator National Response Center (NRC) Report Number

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§191.5 requires that incidents meeting the criteria outlined in §191.3 be reported directly to the **24-hour National Response Center (NRC) at 1-800-424-8802** at the earliest practicable moment . The NRC assigns numbers to each call. Enter the number assigned to the operator’s initial Immediate Notice (sometimes referred to as the “Telephonic Report”). If a NRC report was not made, select the option that best describes why: NRC Notification Not Required, NRC Notification Required But Not Made, Do Not Know NRC Report Number.

A20c. Additional NRC Report Numbers

If the operator made more than one call to the NRC, enter each additional NRC report number.

A21. Did the gas ignite?

Ignite means the released gas caught fire, or a conflagration, detonation or explosion occurred, even if there was no residual fire after the initial ignition event. If the answer is “Yes,” enter the time and date of the ignition in 21a. The time is to be shown by 24-hour clock notation in the time zone where the Incident occurred. If the fire was extinguished, select “Operator/Contractor” or “Local/State/Federal Emergency Responder,” to indicate who extinguished the fire, or select “Allowed to Burn Out,” if it was not extinguished, in 21b. Enter the estimated volume of gas consumed by fire in thousands of standard cubic feet, MCF in 21c.

A21d. Did the gas explode?

Explode means the ignition of the released gas occurred with a sudden and violent release of energy.

A22. Flow Control

If A14. is “Onshore Pipeline, Including Valve Sites” OR “Offshore Pipeline, Including Riser and Riser Bend”, answer A22.

The initial response to gas pipeline emergencies is typically understood to be isolation of the incident location from the source of gas. However, sometimes there are operational means other than valve closures to achieve this goal. These questions are intended to understand the response actions and the time of valve closures intended to isolate the incident location. Valve data is for the first upstream or downstream valve selected by the operator to minimize the release volume but may not be the closest to the incident site or the one that was eventually used for the final isolation of the release site for repair.

Upstream of Failure - If an action other than valve closure was taken to isolate the incident site from the upstream pipeline, select “Operational Control” for 22a and provide a description of the operation control employed.

If 22a. is “Valve Closure”, complete 22b. and 22c.

A22b. Enter the time of the valve closure that achieved isolation of the incident location from upstream piping.

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A22c. Identify the type of valve used to initially isolate the release on the upstream side.

Downstream of Failure - If an action other than valve closure was taken to isolate the incident site from the downstream pipeline, select “Operational Control” for 22d. and provide a description of the operation control employed.

If 22d. is “Valve Closure”, complete 22e. and 22f.

A22e. Enter the time of the valve closure that achieved isolation of the incident location from downstream piping.

A22f. Identify the type of valve used to initially isolate the release on the downstream side.

A23. Number of general public evacuated

The number of people evacuated is to be estimated based on operator knowledge, or police, fire department, or other emergency responder reports. If there was no evacuation involving the general public, report zero (0).

PART B – ADDITIONAL LOCATION INFORMATION

B1. Was the origin of the incident onshore?

Populated automatically based on response to A14.

B1a. Pipeline/Facility name

Multiple pipeline systems and/or facilities are often operated by a single operator. This information identifies the particular pipeline system or pipeline facility name commonly used by the operator on which the incident occurred, for example, the “West Line 24” Pipeline”, or “Gulf Coast Pipeline”, or “Wooster Storage Facility”.

B1b. Segment name/ID

Within a given pipeline system and/or facility, there are typically multiple segment or station identifiers, names, or ID’s which are commonly used by the operator. The information to be reported here helps locate and/or record the more precise incident location, for example, “Segment 4-32”, or “MP 4.5 to Wayne County Line”, or “Dublin Compressor Station”, or “Witte Reducing Station”. Consideration should be given to using the same pipeline segment name that was submitted to NPMS, where appropriate.

If Onshore

B2. – B5. Incident Location

Provide the state, zip code, city, and county/parish in which the incident occurred. If the incident did not occur within a municipality, select Not Within Municipality in the City field. If the incident did not occur within county/parish, select Not Within County/Parish.

B6. and B7. Operator-designated location

This is intended to be the designation that the operator would use to identify the location of the incident on its pipeline system. Enter the appropriate milepost or survey station number. This designator is intended to allow PHMSA personnel to refer to the physical location of the incident using the operator’s maps and records.

B8. Was the Incident on Federal Lands other than the Outer Continental Shelf?

Federal Lands other than Outer Continental Shelf means all lands the United States owns, including military reservations, except lands in National Parks and lands held in trust for Native Americans. Incidents at Federal buildings, such as Federal Court Houses, Custom Houses, and other Federal office buildings and warehouses, are NOT to be reported as being on Federal Lands.

B9. Location of Incident

Operator-controlled Property would normally apply to an operator’s facility, which may or may not have controlled access, but which is often fenced or otherwise marked with discernible boundaries. This “operator-controlled property” does not refer to the pipeline right-of-way, which is a separate choice for this question.

B10. Area of Incident (as found)

This refers to the location on the pipeline system at which gas was released, resulting in the incident. It does not refer to adjacent locations in which released gas may have accumulated or ignited.

Underground means pipe, components, or other facilities installed below the natural ground level, road bed, or below the underwater natural bottom.

Under pavement includes under streets, sidewalks, paved roads, driveways, and parking lots.

Exposed due to Excavation means that a normally buried pipeline had been exposed by any party (operator, operator’s contractor, or third party) preparatory to or as a result of excavation. The cause of the release, however, may or may not necessarily be related to excavation damage. This category could include a corrosion leak not previously evidenced by dead vegetation, but found during an ILI dig, or a release caused by a non-excavation vehicle where contact happened to occur while the pipeline was exposed for a repair or examination. Natural forces might also damage a pipeline that happened to be temporarily exposed. In each case, the cause is to be appropriately reported in PART G of this form.

Exposed due to loss of cover means that erosion, flooding, or some other non-excavation action has removed the cover that was previously over the pipeline. This loss of cover may be previously known or unknown by the pipeline operator, but to be reported in this category, the pipeline was believed to have been exposed prior to the Incident. **Loss of cover as a result of the Incident should not be reported under this category. For example** – if a pipeline was buried below ground immediately prior to a failure, and the force of the failure unearthed the pipeline – it should still be reported as “Under soil,” for the purposes of this report.

Aboveground means pipe, components, or other facilities that are above the natural grade.

Typical aboveground facility piping includes any pipe or components installed aboveground such as those at compressor stations, valve sites, launcher and receiver and reducing stations.

Transition area means the junction of differing material or media between pipes, components, or facilities such as those installed at a belowground-aboveground junction (soil/air interface), another environmental interface, or in close contact to supporting elements such as those at water crossings, compressor stations, and gas storage facilities.

If B10. is Underground, answer 10a. and 10b:

B10a. Depth of Cover

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Report the depth of cover in inches immediately before the incident. In cases where the incident changed the depth of cover, the depth prior to the incident will be an estimate.

B10b. Indicate if other underground facilities were found within 12 inches of the failure location.

B11. Did Incident occur in a crossing?

Use **Bridge Crossing** if the pipeline is suspended above a body of water or roadway, railroad right-of-way, etc. either on a separately designed pipeline bridge or as a part of or connected to a road, railroad, or passenger bridge.

Use **Railroad Crossing** or **Road Crossing**, as appropriate, if the pipeline is buried beneath rail bed or road bed.

Use **Water Crossing** if the pipeline is in the water, beneath the water, in contact with the natural ground of the lake bed, etc., or buried beneath the bed of a lake, reservoir, stream or creek, whether the crossing happens to be flowing water at the time of the incident or not. The name of the body of water is to be provided if it is commonly known and understood among the local population. (The purpose of this information is to allow persons familiar with the area in which the incident occurred to identify the location and understand it in its local context. Research to identify names that are not commonly used is not necessary since such names would not fulfill the intended purpose. If a body of water does not have a name that is commonly used and understood in the local area, this field may be left blank).

For **Approximate water depth (ft)** of the lake, reservoir, etc., estimate the typical water depth at the location and time of the incident, ignoring seasonal, weather-related, and other factors which may affect the water depth from time to time.

If B11 is yes, indicate whether the pipe is cased.

If a water crossing, specify the pipe installation method and answer the question about the length of the crossing.

If Offshore

B12. Approximate water depth (ft.) at the point of the Incident

This is to be the estimated depth from the surface of the water to the seabed at the point of the incident regardless of whether the pipeline is below/on the bottom, underwater but suspended above the bottom, or above the surface (e.g., on a platform).

B13. Origin of the Incident

Area and Tract/Block numbers are to be provided for either State or OCS waters, whichever is applicable.

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For Nearest County/Parish, as with the name of an onshore body of water (see Question 12 above), the data collected is intended to allow persons familiar with the area in which the incident occurred to identify the location and understand it in its local context. Accordingly, it is not necessary to take measurements to determine which county/parish is precisely “nearest” in cases where the incident location is approximately equidistant from two (or more). In such cases, the name of one of the nearby counties/parishes is to be provided.

For Incidents on the Outer Continental Shelf (OCS), identify the region where the Incident occurred by selecting one of the four options listed.

B15. Area of the Incident

For all Offshore Incidents, specify the area of the Incident by selecting the best description of the location where the Incident occurred.

PART C – ADDITIONAL FACILITY INFORMATION

C1. Is the pipeline or facility [Interstate or Intrastate]?

Interstate gas pipeline facility means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (15 U.S.C. 717 et seq.).

Intrastate gas pipeline facility means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas within a state and is not subject to the jurisdiction of FERC under the Natural Gas Act (15 U.S.C. 717 et seq.).

The reported jurisdiction should match both the Annual Report and NPMS submittals for the pipeline, if applicable.

C2. Material involved in Incident

Enter the material involved in the Incident. If the material is other than Carbon Steel or Plastic, select “Material other than Carbon Steel or Plastic” and specify the type of material in the space provided.

C3. Item involved in Incident

Pipe (whether pipe body or pipe seam) means the pipe through which product is transported, not including auxiliary piping, tubing, or instrumentation.

Nominal Pipe Size. It is the diameter in whole number inches (except for pipe less than 5”) used to describe the pipe size; for example, 8-5/8” pipe has a nominal pipe size of 8. Decimals are unnecessary for this measure (except for pipe less than 5”). For more details, see http://en.wikipedia.org/wiki/Nominal_Pipe_Size

Enter **pipe wall thickness** in inches. Wall thickness is typically less than an inch. Accordingly, use three decimal places to report wall thickness: 0.312, 0.281, etc.

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SMYS means specified minimum yield strength and is the yield strength prescribed by the specification under which the material is purchased from the manufacturer. If the SMYS is unknown, and the Operator has designated it as 24,000 for the purposes of MAOP calculations, enter 24,000.

Pipe Specification is the specification to which the pipe was manufactured, such as API 5L or ASTM A106.

Pipe seam means the longitudinal seam (longitudinal weld) created during manufacture of the joint of pipe.

Pipe Seam Type Abbreviations

SAW means submerged arc weld

ERW means electric-resistance weld

DSAW means double submerged arc weld

If the frequency of the ERW pipe seam is unknown, and the pipe was manufactured after 1980, select Longitudinal ERW – High Frequency. Almost all ERW pipe manufactured prior to 1960 is Low Frequency, and both High and Low Frequency ERW pipe was manufactured between 1960 and 1980.

If differences exist between pipe on either side of a Girth Weld Failure, Populate C31. through C3r. as needed.

If the incident occurred on an item not provided in this section, select “Other” and specify the item that failed in the space provided. **Make every effort to find an item category and avoid the use of “Other” when reporting the Type of Item involved in the Incident.**

C4. Year Installed Enter the year the item that failed was installed.

C5. Year Manufactured If you know the year the item that failed was manufactured, enter it. Otherwise, select Unknown.

C6. Type of release involved (*select only one*)

Mechanical puncture means a puncture of the pipeline, typically by a piece of equipment such as would occur if the pipeline were pierced by directional drilling or a backhoe bucket tooth. Not all excavation-related damage will be a “mechanical puncture.” (Precise measurement of size – e.g., using a micrometer – is not needed. Approximate measurements can be provided in inches and one decimal.)

Leak means a failure resulting in an unintentional release of gas that is often small in size, usually resulting in a low flow release of low volume, although large volume leaks can and do occur on occasion. A leak may be a hole or a crack, and includes separation of materials, pullout and loose connections. Typically, a **Leak** can be repaired, whereas a **Rupture** results in the complete failure of the pipeline.

Rupture means the pipeline facility has burst, split, or broken and the operation of the pipeline facility is immediately impaired and no longer serviceable. The terms “circumferential” and “longitudinal” refer to the general direction or orientation of the rupture relative to the pipe’s axis. For example; a rupture of a girth weld would be circumferential, whereas a split that followed the length of the pipe (whether in the seam, or not) would be longitudinal. (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and decimals.)

PART D – ADDITIONAL CONSEQUENCE INFORMATION

See 49 CFR § 192.903 for “high consequence area” definition.

D1. Select the Class Location at the point of the failure.

D2. Did this Incident occur in a High Consequence Area (HCA)?

This question is to be answered based on the classification of the involved segment in the operator’s Integrity Management (IM) Program at the time of the incident.

D2a. Specify the Method used to identify the HCA:

Answer this question only if the incident occurred in an HCA.

As defined in §192.903, HCAs are determined by one of two methods: Method (1) uses class locations, and Method (2) uses potential impact circles. The operator is to identify the method used within its IM program to determine that the location at which the incident occurred was an HCA.

D3. What is the PIR (Potential Impact Radius) for the location of this Incident?

An operator is to answer this question for all incidents, *regardless of whether or not the incident occurred in a high consequence area (HCA) or of the method used to identify an HCA*. A PIR is one of the two methods for identifying an HCA, and this question and those immediately following are intended to collect data from actual incidents as part of a continuing effort to assure that the definition of a PIR is appropriate for that purpose. If the Incident involved the release of a non-flammable gas, select “Not Flammable.”

PIR is defined in §191.903 as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula:

$$r = 0.69 * \sqrt{p * d^2}$$

where: r is the radius of a circular area in feet surrounding the point of failure,
p is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and
d is the nominal diameter of the pipeline in inches.

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[0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; incorporated into the regulations by reference, see §192.7) to calculate the impact radius formula.]

D4. Were any structures outside the PIR impacted or otherwise damaged by heat/fire resulting from the Incident?

Report any damage to structures further from the point of failure than the PIR distance that resulted from heat radiation or fires started as a result of the incident.

D5. Were any structures outside the PIR impacted or otherwise damaged NOT due to heat/fire resulting from the Incident?

This would include damage by blast effects, impact from flying debris dislodged by a pipeline rupture, etc.

D6. Were any of the fatalities or injuries reported for persons located outside the PIR?

This refers only to the injuries reported in A11. Do not consider less severe injuries reported in D8. and D9. The description of the cause of the fatality or injury should be general in nature. For example; *burns, struck by flying debris, smoke inhalation, crushed by falling object*, are examples of causes that could be used to describe the apparent physical cause of the injury or fatality outside the PIR.

Moderate consequence area (MCA) is defined in 49 CFR Part 192.

D13a. Did the incident occur in an MCA? If yes, complete **D13b.** by selecting all that were present within the potential impact radius.

D7. Estimated Property Damage

All relevant costs available at the time of submission must be included on the initial written Incident Report as well as being updated as needed on Supplemental Reports. This includes (but is not limited to) costs due to property damage to the operator's facilities and to the property of others, facility repair and replacement, and environmental cleanup and damage. Do NOT include cost of gas lost. Additionally, do NOT include costs incurred for facility repair, replacement, or changes that are NOT related to the incident and which are typically done solely for convenience. An example of doing work solely for convenience is working on non-leaking facilities unearthed because of the incident. Litigation and other legal expenses related to the incident are not reportable.

Operators are to report costs based on the best estimate available at the time a report is submitted. It is likely that an estimate of final repair costs may not be available when the initial report must be submitted (within 30 days, per §191.15). The best available estimate of these costs is to be included in the initial report. For convenience, this estimate can be revised, if needed, when Supplemental

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Reports are filed for other reasons, however, when no other changes are forthcoming, Supplemental Reports are to be filed as new cost information becomes available. If Supplemental Reports are not submitted for other reasons, a Supplemental Report is to be filed for the purpose of updating or correcting the estimated cost if these costs differ from those already reported by 20 percent or \$20,000, whichever is greater.

D7a. Public and Non-operator private property damage estimates generally include physical damage to the property of others, the cost of investigation and remediation of a site not owned or operated by the operator, laboratory costs, third party expenses such as engineers or scientists, and other reasonable costs, excluding litigation and other legal expenses related to the incident.

D7b. Operator's property damage & repairs estimates generally include physical damage to the property of the operator or owner company such as the estimated installed or replacement value of the damaged pipe, coating, component, materials, or equipment due to the incident, excluding the cost of any gas lost. Also to be excluded are litigation and other legal expenses related to the incident.

When estimating the **Cost of repairs** to company facilities, the standard shall be the cost necessary to safely restore property to its predefined level of service. Property damage estimates include the cost to access, secure, excavate, and repair the pipeline using methods, materials, and labor necessary to re-establish operations at a predetermined level. These costs may include the cost of repair sleeves or clamps, re-routing of piping, or the removal from service of an appurtenance or pipeline component. When more comprehensive repairs or improvements are justified but not required for continued operation, the cost of such repairs or replacement is not attributable to the incident. Costs associated with improvements to the pipeline or other facilities to mitigate the risk of future failures are not included.

D7c. Emergency response includes emergency response operations necessary to return the incident site to a safe state, actions to minimize the volume of gas released, conduct reconnaissance, and to identify the extent of incident impacts. They include materials, supplies, labor, and benefits. If you reimbursed local, state, or federal emergency responders, include these amounts. Costs related to stakeholder outreach, media response, etc. are not to be included.

D7d. Other costs are to include any and all costs which are not included above. Cost of any gas lost is NOT to be reported here, but is to be reported under **Cost of Gas Released**. Operators are to NOT use this category to report any costs which belong in cost categories separately listed above.

Costs are to be reported in only one category and are not to be double-counted. Costs can be split between two or more categories when they overlap more than one reporting category.

Cost of Gas Released – enter your gas cost, excluding taxes, in dollars per thousand standard cubic feet (mcf). The cost of gas released will be calculated based on the volumes reported in A7 and A8.

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Injured persons not included in A11. The number of persons injured, admitted to a hospital, and remaining in the hospital for at least one overnight are reported in A11. *If a person is included in A11, do not include them in D8.*

D8. Estimated number of persons with injuries requiring treatment in a medical facility but not requiring overnight in-patient hospitalization.

If a person is included in D8, do not include them in D9.

D9. Estimated number of persons with injuries requiring treatment by EMTs at the site of incident.

Buildings Affected The term ‘affected’ means the building was either damaged, or evacuated, or had gas service interrupted.

D10. Enter the number of residential buildings affected.

D11. Enter the number of commercial and industrial buildings affected.

D12. If wildlife was impacted, select Yes and indicate the type in D12a. Otherwise, select No.

PART E – ADDITIONAL OPERATING INFORMATION

E1. Estimated Pressure and Flow Rate

Enter the estimated operating pressure, in psig, at the location and time of the incident.
 Enter the estimated flow rate in the pipeline segment at the location and time of the Incident.

E2. Maximum Allowable Operating Pressure (MAOP)

Enter the MAOP, in psig, at the point and time of the Incident.

E2a. MAOP Established By

Select the response that describes the basis for establishing the MAOP at the incident site. A short explanation of each 192.619 option and “Other” is:

§ 192.619 (paragraph)	Methodology Description
(a)	<i>Introduction: Except as specified in (c) and (d), use the <u>lowest MAOP</u> determined by (a)(1), (a)(2), (a)(3), (a)(4).</i>
(a)(1)	Design Pressure
(a)(2)	Post-Construction Pressure Test
(a)(3)	High Actual Operation Pressure during 5 years preceding July 1, 1970 – this is <u>NOT</u> the Grandfather Clause
(a)(4)	History of Pipe (primarily corrosion and actual operating pressure)
(c)	Grandfather Clause – Highest Actual Operating Pressure during 5 years preceding 1970, even if this MAOP is higher than pressures determined by other methodologies in (a)
(d)	Alternative MAOP (§ 192.620) and Alternative MAOP Special Permits
Other	Use this category if you did not base your MAOP on any of the paragraphs within § 192.619 or 192.624(c)

E2b. and E2c. Enter the date the MAOP was established and indicate if the MAOP was established in conjunction with a flow reversal.

E3. Pressure Description

Select the option that describes the relationship among the operating pressure at the point and time of the incident, the MAOP, and the allowances in §192.201.

E4. Was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP ?

Consider both voluntary and mandated pressure restrictions. A pressure restriction is to be considered mandated by PHMSA or a state regulator if it was required by an Order, enforcement action, or other formal correspondence from PHMSA.

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An “established pressure restriction” is defined as a temporary reduction in the MAOP that also requires a revision to the set points in the operator’s safety devices, processes or controls to ensure the pressure restriction is not exceeded.

Pressure reductions taken by the operator as a result of a procedural or regulatory requirement, e.g., pipeline repairs, movement, investigations, or a pressure reduction taken because an anomaly identified during an IM assessment could not be repaired within the required schedule (§192.933(d)), are not considered “mandated by PHMSA.”

E5. Odorization Indicate if the gas at the point of failure was required to be odorized. If it was required, indicate if the odorization was in accordance with §192.615.

If A14. is “Onshore Pipeline, Including Valve Sites” OR “Offshore Pipeline, Including Riser and Riser Bend”, answer E6 through E8.

E6. Length of segment isolated between valves (ft)

Identify the length in feet between the upstream and downstream shut-off valves closest to the failure location.

E9. Function of pipeline system

Transmission System means pipelines that are part of a system whose principal purpose is transmission of gas.

Transmission Line of Distribution System means a pipeline that meets the definition of “transmission line” in §192.3 but which is operated as part of a distribution pipeline system. Typically, this includes portions of the distribution pipeline system for which the operating stress level exceeds 20 percent SMYS.

Type A and Type B Gathering means a pipeline that transports gas from a current production facility to a transmission line or main and that meets the criteria for either Type A or Type B in §192.8.

Offshore Gathering means a gas gathering pipeline located offshore.

Transmission in Storage Field means a transmission pipeline that transports gas within a storage field.

E10. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?

This does not mean a system designed or used exclusively for leak detection.

E10a. Was it operating at the time of the Incident?

Was the SCADA system in operation at the time of the incident?

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E10b. Was it fully functional at the time of the Incident?

Was the SCADA system capable of performing all of its functions, whether or not it was actually in operation at the time of the incident? If No, describe functions that were not operational in PART H – Narrative Description of the Incident.

E10c and d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the initial indication or confirmed discovery of the Incident?

Select Yes if SCADA-based information was used to confirm the incident even if the initial report or identification may have come from other sources. Use of SCADA data for subsequent estimation of amount of gas lost, etc. is not considered use to confirm the incident.

Select No if SCADA-based information was not used to assist with identification of the incident.

E11. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Incident?

Select only one of the choices to indicate whether an investigation was/is being conducted (Yes) or was not conducted (No). If an investigation has been completed, select all the factors that apply in describing the results of the investigation.

Cause means an action or lack of action that directly led to or resulted in the pipeline incident.

Contributing factor means an action or lack of action that when added to the existing pipeline circumstances heightened the likelihood of the release or added to the impact of the release.

Controller Error means that the controller failed to identify a circumstance indicative of a release event, such as an abnormal operating condition, alarm, pressure drop, change in flow rate, or other similar event.

Incorrect Controller action means that the controller errantly operated the means for controlling an event. Examples include opening or closing the wrong valve, or hitting the wrong switch or button.

PART F – DRUG & ALCOHOL TESTING INFORMATION

Requirements for post-incident drug and alcohol tests are in 49 CFR §199.105 and §199.225 respectively. If the incident circumstances were such that tests were not required by these regulations, and if no tests were conducted, select No. If tests were administered, select Yes and report separately the number of operator employees and the number of contractors working for the operator who were tested and the number of each that failed such tests.

PART G – APPARENT CAUSE

PART G – Apparent Cause

Select the one, single sub-cause listed under sections G1 thru G8 that best describes the apparent cause of the Incident. These sub-causes are contained in the shaded column on the left under each main cause category. Answer the corresponding questions that accompany your selected sub-cause, and enter any secondary, contributing, or root causes of the Incident in PART K – Contributing Factors. **Make every effort to find a category that fits the Incident’s Apparent Cause and avoid the use of Other and Unknown when possible. Use of Unknown as an Apparent Cause will require the submittal of a Supplemental Report to revise the Apparent Cause when it becomes known.**

G1 – Corrosion Failure

Corrosion includes a release or failure caused by galvanic, atmospheric, stray current, microbiological, selective seam, or other corrosive action. A corrosion release or failure is not limited to a hole in the pipe or other piece of equipment. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is to be classified as Corrosion. (Note: If the bonnet, packing, or other gasket has deteriorated to failure, whether before or after the end of its expected life, but not due to corrosive action, it is to be classified under G6 - Equipment Failure.)

External Corrosion

2. Type of corrosion – NOTE: Stress Corrosion Cracking (SCC) is no longer an option for the type of corrosion. SCC failures are to be reported under cause G5, with a sub-cause of Environmental Cracking-related.

If Stray Current corrosion is selected, specify whether alternating or direct current was involved and describe the source of the stray current.

4a. Under cathodic protection means cathodic protection in accordance with §192.455, §192.457, and §192.463. Recognizing that older pipelines may have had cathodic protection added over a number of years, provide an estimate if the exact year cathodic protection started is unknown.

Internal Corrosion

9. Location of corrosion

A **low point in pipe** includes portions of the pipe contour in which water might settle out. This includes, but is not limited to, the low point of vertical bends at a crossing of a foreign line or road/railroad, etc., an elbow, a drop out or low point drain.

10. Was the gas/fluid treated with corrosion inhibitors or biocides?

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Select Yes if corrosion inhibitors or biocides were included in the gas/fluid transported.

12. Were cleaning/dewatering pigs (or other operations) routinely utilized?

13. Were corrosion coupons routinely utilized?

For purposes of these Questions 12 and 13, “routinely” refers to an action that is performed on more than a sporadic or one-time basis as part of a regular program with the intent to ensure that water build-up and/or settling and internal corrosion do not occur.

G2 – Natural Force Damage

Natural Force Damage includes a release or failure resulting from earth movement, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslide, scouring, temperature, frost heave, frozen components, high winds, or similar natural causes.

Earth Movement NOT due to Heavy Rains/Floods refers to incidents caused by land shifts such as earthquakes, landslides, or subsidence, but not mudslides which are presumed to be initiated by heavy rains or floods.

Heavy Rains/Floods refer to all water-related natural force causes. While mudslides involve earth movement, report them here since typically they are an effect of heavy rains or floods.

Lightning includes both damage and/or fire caused by a direct lightning strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by lightning that results in damage to a pipeline system asset which results in an incident.

Temperature includes weather-related temperature and thermal stress effects, either heat or cold, where temperature was the initiating cause.

Thermal stress refers to mechanical stress induced in a pipe or component when some or all of its parts are not free to expand or contract in response to changes in temperature.

Frozen components would include incidents where components are inoperable because of freezing and those due to cracking of a piece of equipment due to expansion of water during a freeze cycle.

High Winds includes damage caused by wind-induced forces. Select this category if the damage is due to the force of the wind itself. Damage caused by impact from objects blown by wind would be reported under G4 - Other Outside Force Damage.

Tree/Vegetation Root includes damages caused by tree and vegetation roots.

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Snow/Ice impact or Accumulation should be indicated when snow and/or ice caused damage to the gas transmission and gathering system asset which results in an incident.

Other Natural Force Damage. Select this sub-cause for types of Natural Force Damage not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Incident.

Answer Questions 6 and 6.a if the incident occurred in conjunction with an extreme weather event such as a hurricane, tropical storm, or tornado. If an extreme weather event related to something other than a hurricane, tropical storm, or tornado was involved, indicate Other and describe the event in the space provided.

G3 – Excavation Damage

Excavation Damage includes a release or failure resulting directly from excavation damage by operator's personnel (oftentimes referred to as “first party” excavation damage) or by the operator’s contractor (oftentimes referred to as “second party” excavation damage) or by people or contractors not associated with the operator (oftentimes referred to as “third party” excavation damage). Also, this section includes a release or failure determined to have resulted from previous damage due to excavation activity. For damage from outside forces OTHER than excavation which results in a release, use G2 - Natural Force Damage or G4 - Other Outside Force, as appropriate. Also, for a strike, physical contact, or other damage to a pipeline or facility that apparently was NOT related to excavation and that results in a delayed or eventual release, report the incident under G4 as “Previous Mechanical Damage NOT related to Excavation.”

Excavation Damage by Operator (First Party) refers to incidents caused as a result of excavation by a direct employee of the operator.

Excavation Damage by Operator’s Contractor (Second Party) refers to incidents caused as a result of excavation by the operator’s contractor or agent or other party working for the operator.

Excavation Damage by Third Party refers to incidents caused by excavation damage resulting from actions by personnel or other third parties not working for or acting on behalf of the operator or its agent.

Previous Damage due to Excavation Activity refers to incidents that were apparently caused by prior excavation activity and that then resulted in a delayed or eventual release. Indications of prior excavation activity might come from the condition of the pipe when it is examined, or from records of excavation at the site, or through metallurgical analysis or other inspection and/or testing methods. Dents and gouges in the 10:00-to-2:00 o’clock positions on the pipe, for instance, may indicate an earlier strike, as might marks from the bucket or tracks of an earth moving machine or similar pieces of equipment.

If Excavation Damage by Third Party is selected, answer question 1

1. and 1a. Prior Notification Indicate whether you received prior notification of the excavation activity. If yes, indicate all of the notification sources.

1b. through 1d. One-Call State Law Exemptions Per the primary Incident Investigator results, indicate whether State law exempted the excavator from notifying a one-call center. If yes, select the type of exemption from the list. If “Other” is selected, enter text describing the exemption. Describe the exempting authority and exempting criteria.

2. – 12. Complete these questions for any excavation damage sub-cause. Instructions for answering these questions can be found at CGA’s web site,

<https://www.damagereporting.org/dr/control/userGuide.do>.

NOTE: If you have or will be reporting the information in questions 2 thru 12 to CGA-DIRT, select “No” in question 2 to avoid duplication of data submitted to CGA.

G4 – Other Outside Force Damage

Other Outside Force Damage includes, but is not limited to, a release or failure resulting from non-excavation-related outside forces, such as nearby industrial, man-made, or other fire or explosion; damage by vehicles or other equipment; failures due to mechanical damage; and, intentional damage including vandalism and terrorism.

Nearby Industrial, Man-made or other Fire/Explosion as Primary Cause of Incident applies to situations where the fire occurred before - and *caused* - the release. (See also the discussion of “secondary ignition” under the *General Instructions*.) Examples of such an incident would be an explosion or fire that originated at a neighboring facility or installation (chemical plant, tank farm, or other industrial facility) or structure, debris, or brush/trees that results in a release at the operator’s pipeline or facility. This includes forest, brush, or ground fires that are caused by human activity. If the fire, however, is known to have been started as a result of a lightning strike, the incident’s cause is to be classified under G2 - Natural Force Damage. Arson events directed at harming the pipeline or the operator are to be reported as G4 - Intentional Damage (see below).

Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation.

An example of this sub-cause would be a stopple tee that releases gas when damaged by a pickup truck maneuvering near the pipeline. Other motorized vehicles or equipment include tractors, backhoes, bulldozers and other tracked vehicles, and heavy equipment that can move. Include under this sub-cause incidents caused by vehicles operated by the pipeline operator, the pipeline operator’s contractor, or a third party and specify the vehicle/equipment operator’s affiliation from one of these three groups. Pipeline incidents resulting from vehicular traffic loading or other contact are to also be reported in this category. If the activity that caused the incident involved digging, drilling, boring, blasting, grading, cultivation or similar excavation activities, report under G3 - Excavation Damage.

Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring. This sub-cause includes impacts by maritime equipment or vessels (including their anchors or anchor chains or other attached equipment) that have lost their moorings and are carried into the pipeline facility by the current. This sub-cause also includes maritime equipment or vessels set adrift as a result of severe weather events and carried into the pipeline facility by waves, currents, or high winds. In such cases, also indicate the type of severe weather event. Do NOT report in this sub-cause incidents which are caused by the impact of maritime equipment or vessels while they are engaged in their normal or routine activities; such incidents are to be reported as “Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation” under this section G4 (see below) so long as those activities are not excavation activities. If those activities are excavation activities such as dredging or bank stabilization or renewal, the incident is to be reported under G3 - Excavation Damage.

Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation. This sub-cause includes incidents due to shrimping, purse seining, dredging, oil drilling, or oilfield workover rigs, including anchor strikes, and other routine or normal maritime-related activities UNLESS: the movement of the maritime asset was inadvertent and due to a severe weather event (this type of incident is to be reported under “Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring” in this section G4); or, the incident was caused by excavation activity such as dredging of waterways or bodies of water (this type of incident is to be reported under G3 - Excavation Damage).

Electrical Arcing from Other Equipment or Facility such as a pole transformer or adjacent facility’s electrical equipment.

Previous Mechanical Damage NOT Related to Excavation. This sub-cause covers incidents where damage occurred at some time prior to the release that was apparently NOT related to excavation activities, and would include prior outside force damage of an unknown nature, prior natural force damage, prior damage from other outside forces, and any other previous mechanical damage other than that which was apparently related to prior excavation. Incidents resulting from previous damage sustained during construction, installation, or fabrication of the pipe or weld from which the release eventually occurred are to be reported under G5 - Material Failure of Pipe or Weld. (See this sub-cause for typical indications of previous construction, installation, or fabrication damage.) Incidents resulting from previous damage sustained as a result of excavation activities should be reported under G3 – Previous Damage due to Excavation Activity. (See this sub-cause for typical indications of prior excavation activity.)

Intentional Damage

Vandalism means willful or malicious destruction of the operator’s pipeline facility or equipment. This category would include arson, pranks, systematic damage inflicted to harass the operator, motor vehicle damage that was inflicted intentionally, and a variety of other intentional acts. (See also the discussion of “secondary ignition” under the *General Instructions*.)

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Terrorism, per 28 CFR §0.85 General Functions, includes the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives. Operators selecting this item are encouraged to also notify the FBI.

Theft of commodity or Theft of equipment means damage by any individual or entity, by any mechanism, specifically to steal, or attempt to steal, the transported gas or pipeline equipment.

Other Describe in the space provided and, if necessary, provide additional explanation in PART H – Narrative Description of the Incident.

Other Outside Force Damage. Select this sub-cause for types of Other Outside Force Damage not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Incident.

5 – 11 Additional Data for Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation

When answering the questions, include information that can be substantiated from police reports or other investigative reports.

The following definitions apply for reporting the type of motorized vehicle in Question 10:

Motorcycle/All-Terrain Vehicle (ATV) - All two or three-wheeled motorized vehicles, and some four-wheeled vehicles are to be reported in this category. Typical vehicles in this category have saddle type seats and are steered by handlebars rather than steering wheels. This category includes motorcycles, motor scooters, mopeds, motor-powered bicycles, and three-wheel motorcycles. Additionally, four-wheeled off-road and all-terrain vehicles (sometimes referred to as “four-wheelers”) are to be reported under this category.

Passenger Car -- All sedans, coupes, and station wagons manufactured primarily for the purpose of carrying passengers and including those passenger cars pulling recreational or other light trailers.

Small Truck - All two-axle, four-tire, vehicles, other than passenger cars. Included in this classification are pickups, panels, vans, and other vehicles such as campers, motor homes, ambulances, hearses, carryalls, and minibuses.

Bus - All vehicles manufactured as traditional passenger-carrying buses with two axles and six tires or three or more axles. This category includes only traditional buses (including school buses) functioning as passenger-carrying vehicles. Modified buses should be considered to be a truck and should be appropriately classified.

Large Truck - All vehicles on a single frame including trucks, camping and recreational vehicles, motor homes, etc., with two or more axles and at least two rear wheels on each side

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When specifying the type of protection in Question 13; select the category “Barricades” for Jersey barriers, fencing, and other structures that are other than Guard Rails or Bollards/Guard Posts. If “Other” is selected, enter text describing the protection.

G5 – Material Failure of Pipe or Weld

Use this section to report material failures **only if** “Item Involved in Incident” (PART C, Question 3) is “**Pipe**” (whether “**Pipe Body**” or “**Pipe Seam**”) or “**Weld.**” Indicate how the sub-cause was determined or if the sub-cause is still being investigated.

This section includes releases in or failures from defects or anomalies within the material of the pipe body or within the pipe seam or other weld due to manufacturing processes, material imperfections, defects resulting from poor construction, installation, or fabrication practices, and in-service stresses such as vibration, fatigue, and environmental cracking.

Design-, Construction-, Installation-, or Fabrication-related includes a release or failure caused by improper design practices, a dent, gouge, excessive stress, or some other defect or anomaly introduced during the process of constructing, installing, or fabricating pipe and pipe welds in the field, including welding or other activities performed at the construction job site. Included are releases from or failures of wrinkle bends, field welds, and damage sustained in transportation to the construction or fabrication site. Not included are failures due to seam defects, which are to be reported as Original Manufacturing-related (see below). If a river crossing were directionally drilled and tied into a buried pipeline without adequate accommodation for expansion and contraction of the pipe in the drill hole and the pipeline facility fails at the tie-in, this represents an improper design practice. Select “Design-, Construction-, Installation-, or Fabrication-related” as the sub-cause.

Original Manufacturing-related (NOT girth welds or other welds formed in the field) includes a release or failure caused by a defect or anomaly introduced during the process of manufacturing pipe, including manufacturing and handling of the plate materials, seam defects and defects in the pipe body. This option is not appropriate for wrinkle bends, field welds, girth welds, or other joints fabricated in the field. Use this option for failures such as those due to defects of the longitudinal weld or inclusions in the pipe body. If the girth welds were completed at the pipe mill (such as in the case of double joints welded prior to delivery to the jobsite) report those failures in this category.

Environmental Cracking-related includes failures by Stress Corrosion Cracking, Sulfide Stress Cracking, Hydrogen Stress Cracking, Hard Spots or other environmental cracking mechanisms.

If **Design-, Construction-, Installation-, or Fabrication-related**, or **Original Manufacturing-related** is selected, then select any contributing factors. Examples of Mechanical Stress include failures related to overburden or loss of support.

5. Post-construction Pressure Test

If you know the post-construction pressure test value, enter it in psig. Otherwise, select “Unknown.”

G6 – Equipment Failure

This section applies to failures of items other than “Pipe” (“Pipe Body” or “Pipe Seam”) or “Weld”.

Equipment Failure includes a release or failure resulting from: malfunction of control/relief equipment including valves, regulators, or other instrumentation; failures of compressors, or compressor-related equipment; failures of various types of connectors, connections, and appurtenances; failures of the body of equipment, vessel plate, or other material (including those caused by construction-, installation-, or fabrication-related and original manufacturing-related defects or anomalies); and, all other equipment-related failures.

Malfunction of Control/Relief Equipment. Examples of this type of incident cause include: overpressurization resulting from malfunction of a control or alarm device; malfunction of a relief valve; valves failing to open or close on command; or valves which opened or closed when not commanded to do so. If overpressurization or some other aspect of this incident was caused by incorrect operation involving human error, the incident is to be reported under G7 - Incorrect Operation.

ESD System Failure means failure of an emergency shutdown system.

Other Equipment Failure. Select this sub-cause for types of Equipment Failure not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Incident.

G7 – Incorrect Operation

Incorrect Operation includes a release or failure resulting from operating, maintenance, repair, or other errors by facility personnel or pipeline controllers, including, but not limited to improper valve selection or operation, inadvertent overpressurization, or improper selection or installation of equipment in the field. If the failure occurs in the pipe body or weld, and is a result of inadequate design or a design error, the Incident is to be reported under G5 – Material Failure of Pipe or Weld, Design-, Construction-, Installation-, or Fabrication-related.

Other Incorrect Operation. Select this sub-cause for types of Incorrect Operation not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Incident.

G8 – Other Incident Cause

This section is provided for incidents whose cause is currently unknown, or where investigation into the cause has been exhausted and the final judgment as to the cause remains unknown, or where a cause has been determined which does not fit into any of the main cause categories listed in sections G1 thru G7. PHMSA will review all G-8 cause selections and determine if it meets the definition of any category listed in G1 thru G7 before a Final Report is accepted for closure. All

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sub cause categories of “Unknown” require a Supplemental Report to be filed before being accepted as Final.

If the incident cause is known but doesn’t fit into any category in sections G1 thru G7, select **Miscellaneous** and enter a description of the incident cause, continuing with a more thorough explanation in PART H - Narrative Description of the Incident.

If the incident cause is unknown at the time of filing this report, select **Unknown** in this section and specify one reason from the accompanying two choices. Once the operator’s investigation into the incident cause is completed, the operator is to file a Supplemental Report as soon as practicable either reporting the apparent cause or stating definitively that the cause remains Unknown, along with any other new, updated, and/or corrected information pertaining to the incident. This Supplemental Report is to include all new, updated, and/or corrected information pertaining to *all* portions of the report form known at this time, and not only that information related to the apparent cause.

Important Note: Whether the investigation is completed or not, or if the cause continues to be unknown, Supplemental Reports are to be filed reflecting new, updated, and/or corrected information *as and when this information becomes available*. In those cases in which investigations are ongoing for an extended period of time, operators are to file a Supplemental Report within one year of their last report for the incident even in those instances where no new, updated, and/or corrected information has been obtained, with an explanation that the cause remains under investigation in PART H – Narrative Description of Incident. Additionally, final determination of the apparent cause and/or closure of the investigation does NOT preclude the need for the operator’s filing of additional Supplemental Reports as and when new, updated, and/or corrected information becomes available.

PART J – INTEGRITY INSPECTIONS

Complete the following if the “Item Involved in Accident” (from PART C, Question 3) is Pipe or Weld and the “Cause” (from Part G) is:

- Corrosion (any subCause in Part G1); or**
- Previous Damage due to Excavation Activity (subCause in Part G3); or**
- Previous Mechanical Damage NOT Related to Excavation (subCause in Part G4); or**
- Material Failure of Pipe or Weld (any subCause in Part G5)**

J1. Internal Inspection Tools

If Yes, for each tool and technology used, select type of internal inspection tool and technology, and indicate year of most recent and previous runs.

Axial Magnetic Flux Leakage (MFL) is an in-line inspection (ILI) tool that uses a non-destructive testing (NDT) method of imposing a magnetic flux in the steel pipe for the detection of corrosion and pitting. The basic principle behind MFL ILI involves magnetizing the steel pipe to a saturation level with a magnetic field. MFL ILI tools can be either low- and high-resolution tools, with more modern tools being high-resolution MFL ILI tools.

Circumferential/Transverse Wave Magnetic Flux Leakage (MFL) is an in-line inspection (ILI) tool that induces the magnetic flux field into the steel pipe in the circumferential direction, which allows the measurement of longitudinally oriented anomalies such as tunnel corrosion and longitudinal weld anomalies.

Ultrasonic is an in-line inspection (ILI) tool that introduces a shear wave ultrasound beam into the steel pipeline inspection area at an angle, which allows detection of abnormalities based on the reflection and refraction of the beam. Can be used to detect and size planar (crack and crack-like) anomalies or measure wall thickness and detect instances of wall loss.

Geometry/Deformation is an in-line inspection (ILI) tool designed to record mechanical or geometric conditions such as changes in the pipe internal diameter, including dents, ovalities, wrinkles, expansions, and misalignments.

Electromagnetic Acoustic Transducer (EMAT) is an in-line inspection (ILI) tool that generates an ultrasonic pulse within the steel pipe without a liquid couplant. EMAT ILI consists of a magnet and an electrical coil, which uses electro-magnetic forces to introduce sound energy into the steel pipe. EMAT ILI is used to detect cracking flaws in steel pipe.

Cathodic Protection Current Measurement (CPCM) is an in-line inspection (ILI) tool capable of reading and recording the magnitude and polarity of current supplied by cathodic protection (CP). CPCM ILI measures direct current (DC) and alternating current (AC) voltage gradients from CP current or induced AC as the CPCM ILI tool traverses along the pipeline.

**Complete J1b. only when the “Cause” (from Part G) is:
Previous Damage due to Excavation Activity (subCause in Part G3); or
Previous Mechanical Damage NOT Related to Excavation (subCause in Part G4)**

J1b. Indicate if you have reason to believe the internal inspections were completed before the damage was sustained.

J2. Hydrotest Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?

Information from the initial post-construction hydrostatic test is NOT reported in J2.

J3. Direct Assessment (DA) Has Direct Assessment been conducted on this segment?

This refers to direct assessment as defined in §192.903. Instances in which one or more indirect monitoring tools (e.g., close interval survey, DCVG) have been used that might be used as part of direct assessment but which have not been used as part of the direct assessment process defined in §192.903 do NOT constitute a Direct Assessment for purposes of this question.

If J3. is yes, enter the year of the most recent assessment(s) in J3a.

J4. Non-destructive Examination

Indicate if one or more non-destructive examination been conducted prior to the Incident at the point of the Incident since January 1, 2002. If Yes, enter the most recent year of the examination(s) in J4a.

PART K – CONTRIBUTING FACTORS

Contributing factor means an action or lack of action that when added to the existing circumstances heightened the likelihood of the release or added to the impact of the release. The Apparent Cause of the accident is contained in Part G. Do not report the Apparent Cause again in this Part K. If Contributing Factors were identified, select all that apply and explain each in the Narrative.

PART H – NARRATIVE DESCRIPTION OF THE INCIDENT

Concisely describe the incident, including the facts, circumstances, and conditions that may have contributed directly or indirectly to causing the incident. Include secondary, contributing, or root causes when possible, or any other factors associated with the cause that are deemed pertinent. Use this section to clarify or explain unusual conditions, and to explain any estimated data.

If you selected Miscellaneous in section G8, the narrative is to describe the incident in detail, including all known or suspected causes and possible contributing factors.

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PART I – PREPARER AND AUTHORIZED PERSON

The Preparer is the person who compiled the data and prepared the responses to the report and who is to be contacted for more information (preferably the person most knowledgeable about the information in the report or who knows how to contact the person or persons most knowledgeable). Enter the Preparer's e-mail address if the Preparer has one, and the phone and fax numbers used by the Preparer.

The Authorized Person is responsible for assuring the accuracy and completeness of the reported data. In addition to their title, a phone number and email address are to be provided for the Authorized Person.