White Paper on
Gas Pipeline
Controller Risk Analysis

INGAA Pipeline Safety Committee
AGA Gas Control Committee
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BACKGROUND

The Pipeline Safety Act of 2002 stated the following:

(b) PILOT PROGRAM FOR CERTIFICATION OF CERTAIN PIPELINE WORKERS.—
(1) IN GENERAL.—Not later than 36 months after the date of enactment of this Act, the Secretary of Transportation shall—
(A) develop tests and other requirements for certifying the qualifications of individuals who operate computer-based systems for controlling the operations of pipelines; and
(B) establish and carry out a pilot program for 3 pipeline facilities under which the individuals operating computer-based systems for controlling the operations of pipelines at such facilities are required to be certified under the process established under subparagraph (A).
(2) REPORT.—The Secretary shall include in the report required under section 60131(h), as added by subsection (a) of this section, the results of the pilot program. The report shall include—
(A) a description of the pilot program and implementation of the pilot program at each of the 3 pipeline facilities;
(B) an evaluation of the pilot program, including the effectiveness of the process for certifying individuals who operate computer-based systems for controlling the operations of pipelines;
(C) any recommendations of the Secretary for requiring the certification of all individuals who operate computer-based systems for controlling the operations of pipelines;
and
(D) an assessment of the ramifications of requiring the certification of other individuals performing safety-sensitive functions for a pipeline facility.
(3) COMPUTER-BASED SYSTEMS DEFINED.—In this subsection, the term ‘‘computer-based systems’’ means supervisory control and data acquisition systems.

The provisions stated above apply to all pipelines including gas transmission, hazardous liquid transmission, gas distribution and jurisdictional gathering.
PURPOSE

This White Paper is intended to explain current gas transmission and distribution pipeline system control operations, computer based systems used by gas pipeline operators, and processes in place to qualify gas transmission and distribution control personnel.

This White Paper also explains the operation of natural gas pipelines from the control standpoint in order to show that:

• control personnel can not cause a pipeline to fail, and
• that they can not cause the impact from a failure to be increased due to action or inaction, and
• that their role in recognizing and reacting to a potential pipeline failure, is limited until confirmation of a pipeline failure is achieved and the impact of loss of service is weighed against the impact from the failure.

This information is critical in assessing the need for certification of pipeline controllers.

ANALYSIS OF PHMSA AND NTSB INCIDENT REPORTS

It is very important to look at historical incidents to determine if natural gas controllers were the cause or contributed to the consequences of an incident. Review of 10 years of PHMSA incident data shows that there have been no pipeline incidents caused by gas pipeline controllers. None of the NTSB investigations identified gas controller operation as a cause or contributing affect of any gas transmission pipeline incident. Conversations with the gas controllers confirmed that there were no incidents known to have been caused by the gas control function or by gas controllers.

Analysis of the gas control operation confirmed that there is no safety consequence from a controller’s actions or inactions. The controller can not cause an incident and can not contribute to an incident. With no known incidents caused by gas controllers and with no consequences identified, the risk, which is the product of consequence and likelihood, is extremely low.

National Transportation Safety Board Reports

The National Transportation Safety Board (NTSB) routinely reviews pipeline incidents and generates reports of their findings. The Department of Transportation, Pipeline & Hazardous Materials Safety Administration’s (PHMSA) looked at the NTSB reports and found that ten seemed to have some relation to pipeline controllers. These reports dated from 1996 through 2000. No reports after 2000 were found. Nine of the ten reports dealt with incidents on hazardous liquid pipelines. Only one report dealt with a gas pipeline. A detailed review of the single gas pipeline incident shows that it did not involve the pipeline controller. The report states the following:

1 National Transportation Safety Board Pipeline Accident Summary Report PR98-916501, NTSB/PAR-98/01/SUM, Natural Gas Pipeline Rupture and Fire During Dredging of Tiger Pass, Louisiana, October 23, 1996
“The Safety Board notes that about 30 minutes elapsed between the time of the rupture and the time Tennessee Gas became aware that one of its pipelines may have ruptured and that more than an hour passed before the pipeline was shut down. A check valve downstream of the rupture closed automatically after the break to limit the backflow of product to the rupture, but the SCADA system used by Tennessee Gas did not report the check valve’s closing to pipeline controllers. Had it done so or had the company’s SCADA system been equipped with an alarm that responded to a change in pressure over a period of time, the pipeline controllers may have been alerted to an anomaly within a certain segment of the pipeline, and the flow of gas feeding the fire in Tiger Pass may have been terminated more quickly than it was.

Insufficient evidence was available to indicate what effect, if any, the earlier shutoff of the gas flow would have had on this accident. Clearly, however, one of the first priorities in any accident involving the release of natural gas should be to curtail the escape of the product. The Safety Board concludes that the delay in recognition by Tennessee Gas that it had experienced a pipeline rupture at Tiger Pass was due to the piping system’s dynamics during the rupture and to the design of the company’s SCADA system. The Safety Board believes that Tennessee Gas should review its SCADA system and make any modifications necessary to increase the likelihood that any critical event involving the company’s pipelines is quickly and accurately reported to pipeline controllers, allowing them to take timely action to correct or limit the effects of any failure in the pipeline system.”

This NTSB finding deals with Supervisory Control and Data Acquisition (SCADA) design as opposed to pipeline controller actions.

**Pipeline and Hazardous Materials Safety Administration Incident Reports**

**Gas Transmission Pipelines**

PHMSA incident data for gas transmission pipelines, filed by operators using RSPA Form 7100.2 (01-2002), were reviewed in order to ascertain the number and magnitude of reportable incidents caused by Incorrect Operations by the pipeline controller. The 2002 through 2004 data were reviewed first. The data for these years were chosen because of the changes in data gathering, which provided greater data resolution. “Incorrect Operation” addresses incidents where the main contributor involves personnel actions such as inadequate procedures, inadequate safety practices or failure to follow procedures. These statistics demonstrate that only five of the reportable incidents resulted from Incorrect Operations. None of these incidents involved gas pipeline controllers.

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2 The Pipeline and Hazardous Materials Safety Administration, PHMSA, maintains information about Incidents on their website at http://ops.dot.gov/
Additional PHMSA incident data for gas transmission pipelines were mined in 2004 for the years 1995 through 2001. This data mining was done for two research reports, one for the Pipeline Research Committee International (PRCI) and one for the Gas Technology Institute (GTI). In this case, Kiefner and Associates reviewed and corrected as needed, the PHMSA incident data in order to reclassify data under the old (pre-January 2002) cause categories into the cause categories currently used. Review of this data shows that for the seven years, 1995 through 2001, there were 26 incidents where the incident cause was due to Incorrect Operations (The old Category was Operator Error). None of these incidents involved gas pipeline controllers.

Gas Distribution Pipelines
PHMSA incident data for gas distribution pipelines filed by operators using RSPA Form 7100.1 (03-04) were also reviewed in order to ascertain the number and magnitude of reportable incidents caused by Incorrect Operations by the pipeline controller. Since data gathering changes were instituted in March 2004 providing more resolution, data from March through December 2004 were reviewed first. Again, these statistics demonstrate only a small number of reportable incidents resulted from Incorrect Operations. For this period, there were a total of six incidents where the cause was due to Incorrect Operations. None of these incidents involved gas pipeline controllers.

Due to the limited data from 2004, the incident data for 1995 through February 2002 were reviewed. Review of this data shows that for the nine years, there were 54 incidents where the cause was categorized as Accidentally Caused by Operator. Of the 54 incidents, all but three were clearly not caused by controller action. Conversations with the three operators were held and the operators confirmed that none of these incidents were caused by pipeline controllers. Thus, the review showed that there have not been any failures of gas pipeline facilities as caused by gas pipeline controllers for the ten years reviewed, 1995 through 2004.

PHYSICAL CHARACTERISTIC OF A NATURAL GAS TRANSMISSION AND DISTRIBUTION OPERATIONS AND INCIDENTS

Much has been written on the consequences of natural gas transmission failures. Some of this work has been incorporated into the present pipeline safety regulations. Essentially, in a worst case scenario (full guillotine rupture with quick ignition), the amount of heat radiation at a site declines exponentially as the natural gas inventory in the pipeline decompresses. This situation occurs within the first few minutes of a worst case incident, essentially negating any engineering or manual intervention. The addition of fuel from upstream or downstream sources (gas flow is approximately 15 mph) is significantly smaller than the inventory already in the pipe and occurs significantly later in the progression of the incident. Essentially, any evacuations (managed or unmanaged) around the incident area have occurred and local incident management is in effect.

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3 Typographical data errors were corrected based on company interviews
4 GRI-00/0189 “A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines”; Gas Research Institute;2000
Characteristics of Natural Gas Pipelines as compared to Hazardous Liquid Pipelines and Electric Transmission Systems

It is useful to compare and contrast three energy delivery systems – natural gas pipelines, liquid pipelines and electric transmission lines – that utilize SCADA control systems for management of the system. From an outside view, these would appear to be identical in design and operation, but a closer look shows that there are significant differences in the time to detect and respond to a situation before it becomes a public safety concern.

In general, a controller’s job is to control the entry and exit of natural gas, liquids or electricity into the energy transmission system. How much of this product is moved is a function of how much energy is expended to move the product. When the amount of product exceeds the capability of a line (pipeline or electric transmission line) there is a possibility of failure of the line. Electric transmission lines will fail due to overheating because the capacity is exceeded. Natural gas and hazardous liquid pipelines can fail if they are significantly over pressurized.

As mentioned previously, all except one of the NTSB incidents mentioned by PHMSA in the Docket notice5 occurred on hazardous liquid pipelines. There are differences between gas and liquid pipeline systems that may help to explain the differences in probability of an incident occurring as a result of a pipeline controller action.

Natural gas transmission, of the three energy transportation modes studied, permits simple, redundant, decentralized pressure control systems that prevents over pressuring of the system. These same characteristics allow pipeline controllers sufficient time to recognize and respond to abnormal conditions that may be leading to over pressuring situations.

Hazardous Liquid Pipelines

The source of energy for increasing the pressure on a liquid line is a pump. Controlling the speed and load of the pump has the effect of changing the pressure on the downstream pipeline. Elevation has a big impact on liquid lines due to the inherent weight of the product being transported. Also, momentum of the working fluid is a significant factor also because of the weight of the product.

A distinguishing physical property of liquids is incompressibility. Hazardous liquid in pipelines is essentially incompressible; so, any additional product that is added at the receipt end of the pipe without a corresponding delivery rapidly increases the pressure in the pipeline. This lack of compressibility tends to result in real-time, essentially instantaneous detection of pressure variances at the site of the variance (e.g., valve closure). There may be a slight slowing of the detection time of pressure variances at locations farther from the site due to the viscosity effects of the liquid in the pipeline, but in general, the response time in hazardous liquid pipeline systems is fairly quick. This permits the controller to see pressure transients almost instantaneously. Response to variations of inventory change (e.g., pump startup) are rapid on liquid pipelines, and

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5 Docket No. RSPA-04-18584; Notice 1
depending on the viscosity of the liquid, can result in pressure spikes as the system moves from a transient mode to a steady state mode. The weight of the liquid, which can be significant on liquid pipelines with major elevation changes, can compound the effects of the pressure transients. This will, in turn, afford minimal detect and response times (seconds).

The present environmental regulations limit the ability to design in a multitude of decentralized relief points on the system where excess product could be discharged in high pressure situations.

**Natural Gas Pipelines**

The source of energy for increasing the pressure on a natural gas pipeline is a compressor. Controlling the speed and load of the compressor has the effect of changing the pressure on the downstream pipeline. Elevation is not a significant factor due to the low density of the compressed natural gas. Momentum of the working fluid is not a factor because of the compressibility of the product.

A distinguishing physical property of gases is the compressibility. Natural gas is a compressible fluid and as such, can sustain large variations of inventory packed into a pre-defined physical space (e.g. pipeline). For instance, the volume of natural gas stored in a section of pipeline at Maximum Allowable Operating Pressure (MAOP) is typically 30 to 60 times smaller than the volume of gas at atmospheric pressure. Hence, the compressibility of the gas distinguishes it from the liquid and provides the buffer to support increased response times.

Since natural gas transmission pipelines typically operate between pressures of 50% and 100% MAOP, inventory change rates accommodate slow transient response time (several minutes) for pressure increases and decreases. Therefore, the amount of time it takes to detect a sudden change (e.g., pressure drop) in the gas inventory of a pipeline can be significantly longer than the time required to detect a similar pressure change in a hazardous liquid line. Correspondingly, this allows more time (several minutes) for human, mechanical and electronic control systems to react to control excessive pressure transients.

In the event of over-pressurizing, both natural gas and hazardous liquid pipelines have over-pressure protection systems. These systems typically consist of either monitor regulators for gas systems or pressure relief mechanisms for gas and liquid systems. In the case of pressure relief mechanisms, these devices allow excess inventory to escape the pipeline, hence controlling the maximum operating pressure. There is a significant difference between natural gas and hazardous liquid pressure relief control mechanisms. For natural gas systems, over-pressure protection is typically provided through the use of monitor regulators, and excess natural gas is allowed to release to the atmosphere through relief valves. Thus, as a built-in safety mechanism, unlimited volumes of over-pressurized natural gas can vent from the pipeline at many different locations. Hazardous liquids, because of stringent environmental as well as public safety concerns, must be
contained. Thus, the release volume of liquid is limited by the location and size of the containment provided.

**Electric Transmission Grid Systems**
The source of energy for increasing the voltage and amperage on an electric transmission line is a generator. Controlling the speed and load of the generator has the effect of changing the voltage and amperage on the downstream transmission line. Elevation and momentum is not a significant factor but it is highly critical to match load with supply.

The electric transmission industry relies heavily on the use of SCADA systems for energy flow control. These systems have extremely short response times. Instead of controlling pressure, they control voltage and reactive power. A good example of the response time of the electric grid is the study\textsuperscript{6} of the Eastern U.S. blackout that occurred in 2003. As seen from this report, the ripple effect is measured in milliseconds because of the lack of storage capability in the system. Another key factor in the control of the electric grid system is that there is no relief capability (i.e. relief valves) to unload excess energy that is not used. These physical characteristics make the man-to-machine interface the most critical of the three systems analyzed.

The table below summarizes the detection time and response time of various energy transportation systems.

<table>
<thead>
<tr>
<th>MODE</th>
<th>SIGNAL</th>
<th>DETECTION TIME</th>
<th>RESPONSE TIME</th>
<th>CONTROL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Transmission</td>
<td>Voltage</td>
<td>Milliseconds</td>
<td>Milliseconds</td>
<td>Breakers</td>
</tr>
<tr>
<td>Liquid Pipeline</td>
<td>Reactive Power</td>
<td></td>
<td></td>
<td>Generators</td>
</tr>
<tr>
<td>Hazardous Liquid</td>
<td>Pressure</td>
<td>Seconds</td>
<td>Seconds</td>
<td>Valves</td>
</tr>
<tr>
<td>Pipeline</td>
<td></td>
<td></td>
<td></td>
<td>Pumps</td>
</tr>
<tr>
<td>Natural Gas Pipeline</td>
<td>Pressure</td>
<td>Minutes</td>
<td>Minutes</td>
<td>Valves</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Compressors</td>
</tr>
</tbody>
</table>

The table below summarizes the pressure relieving detection time and relief time of energy pipelines.

<table>
<thead>
<tr>
<th>MODE</th>
<th>DETECTION TIME</th>
<th>RESPONSE TIME</th>
<th>EXHAUST</th>
<th>TRANSIENT EFFECT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hazardous Liquid</td>
<td>Seconds</td>
<td>Minutes</td>
<td>Limited to tanks or ponds</td>
<td>Possible Water</td>
</tr>
<tr>
<td>Pipeline</td>
<td></td>
<td></td>
<td></td>
<td>Hammer</td>
</tr>
<tr>
<td>Natural Gas Pipeline</td>
<td>Minutes</td>
<td>Minutes</td>
<td>Open to atmosphere</td>
<td></td>
</tr>
</tbody>
</table>

\textsuperscript{6} http://www.energy.gov/engine/doe/files/dynamic/1282003113351_BlackoutSummary.pdf
MANAGING THE INCORRECT OPERATIONS THREAT

It is important to understand the scope of the natural gas controller as compared to other modes of transportation. In some modes, such as:

- pilots and air traffic controllers,
- train operators and switching operators,
- ship captains and harbor operators,
- automotive vehicle operators and traffic regulators

The safe operation of the system is highly dependent on the qualifications and correct behavior of the controllers of the equipment. Many of the control systems utilized in those modes to prevent incidents are directly controlled and highly dependent on the skill and behavior of the controller. In the case of natural gas pipeline controllers, the ability to affect public safety for the most part has been isolated by design. Items of concern that remain have been identified and addressed through venues such as PHMSA operator qualification regulations.

Present PHMSA Qualification Requirements

According to the Integrity Management Regulations\(^7\) and ASME B31.8S\(^8\), the Incorrect Operations threat is managed through:

- Comprehensive and current procedures
- Adequately trained personnel to carry out the procedures
- Internal Audits to ensure that procedures are followed
- Review of failures caused by incorrect operations

Pipeline operators from over three-dozen major natural gas transmission and distribution companies were surveyed for this analysis in order to ascertain current industry practices in these areas. Operators take very seriously the safe transportation of gas through their systems and maintain up-to-date procedures for the pipeline control personnel. These procedures include operating procedures, emergency procedures and crisis communication procedures.

All pipeline controllers fall under the provisions of the operator qualification regulations found in 49 CFR Part 192, Subpart N. As such, these individuals are trained and qualified in accordance with those regulations and company operator qualification programs.

PHMSA is in the progress of preparing a report on the success of the present operator qualification regulations which should be published shortly.

The controller must be proficient in communication protocols, in recognizing abnormal operating conditions, and in emergency response protocols. Training is extensive and

\(^{7}\) 49 CFR Part 192, Subpart O
\(^{8}\) ASME B31.8S, Managing System Integrity of Gas Pipelines
pipeline companies have one or more elements in their training plans such as training on the fundamental characteristics of natural gas, understanding of the individual pipeline system, supervised operation of the pipeline system and written exams. In addition, all of these steps are completed and proficiency shown before an individual receives management approval to operate the system without direct oversight by an experienced and qualified controller.

All of the interviewed pipeline operators have in place internal audit programs where the pipeline control operation and processes are reviewed on a periodic basis; this review looks at personnel qualification, procedures, records, management of change and other areas. This internal review process serves as an enforcement process.

Finally, all of the interviewed pipeline operators have a failure review or lessons learned process. This process provides for the review by all pipeline controllers, any action which caused an outcome contrary to expectations. In some cases these lessons are programmed into the simulators used by the controllers to be qualified.

Natural gas pipeline controller responsibilities can be classified into two categories, normal operations and abnormal operations. Normal operational functions basically involve business practices and decisions and do not affect public safety. The inherent design of the natural gas transmission and distribution system prevents the normal operational responses from creating abnormal situations.

The controller’s abnormal operations responsibilities involve recognizing that an incident may have occurred, contacting appropriate operating personnel and maintaining service around the incident. Natural gas pipeline controllers are now qualified under the present PHMSA operator qualification regulations and are trained to act in abnormal situations by recognizing an abnormal situation and contacting pipeline personnel to respond to the situation.

NATURAL GAS PIPELINE SYSTEM DESIGN

Natural gas pipeline systems are engineered systems and as such have many characteristics designed into them to minimize the potential of an incident

Redundant Safety Systems
Interviews with pipeline controllers showed that the controller cannot do anything to cause a pipeline incident. The gas controller cannot contribute to or exacerbate an incident. What the gas controller can do and has demonstrated ability to do is to respond to alarms that indicate an abnormal operation of the pipeline system.

The gas controller cannot compromise the mechanical devices which make up a pipeline system. These mechanical devices have their own limits hard-wired or preset set into the equipment. Compressors have individual logic systems with preset limits and shutdowns and separate over-pressure protection systems. Flow regulators have pressure overrides set at MAOP and over-pressure protection as well.
If the gas controller attempts to set a pressure above MAOP for instance, the mechanical
device, be it a compressor, pressure regulator, or flow regulator will not allow MAOP to
be exceeded. If the gas controller inadvertently closes a valve, the pressure upstream will
be limited by the mechanical setting of the upstream equipment, which cannot exceed
MAOP.

The pipeline system is designed for fail-safe operation and has sufficient redundancy or
back up, to prevent failures. There are always at least two devices, one to control pressure
or flow and one to prevent over-pressure of the pipeline. One device can be under control
of the controller subject to the built-in protection; the over-pressure protection device is
never controlled by the controller. In the case of a flow control valve, which is the typical
method to control flow to a customer, the flow can be controlled by the pipeline
controller. However, the device has a pressure override set at MAOP which takes over if
the flow is such that MAOP is being approached. In addition, there is an over-pressure
protection device such as a monitor regulator or relief valve. Also, bypass of the control
equipment requires hands-on operation and cannot be operated by the gas controller.

Other safety designs for the pipeline system are in place, which prevents inappropriate
action by the gas controller. A flow regulator, where the pressure override takes over,
requires a manual reset at its site by field personnel. A compressor shutdown due to over-
pressure, vibration, high temperature, etc. also requires manual reset at its site by field
personnel. These safeguards prevent the gas controller from overriding a safety system.
Field intervention on site is required in order that the safety of the system can be assured
after a shutdown.

SCADA Systems
SCADA systems provide electronic supervision of the system which includes the remote
control of the equipment. The SCADA system is also used for data acquisition in order to
acquire information about the status of the remote equipment for display or for recording
functions. SCADA systems tend to be standalone, redundant systems with backup in
most cases. Access to the systems varies depending on individual company decisions.
Some companies keep the SCADA systems completely separated from other company
systems including the internet. Dialup directly to the SCADA system is sometimes
provided.

Some companies do have communication ties between the SCADA system and other
business systems. Intranet and dialup access may be provided. In some cases, access is
“read only”. In other cases the gas controllers can operate remotely via dialup or high-
speed internet access. In all cases, firewalls and other systems are in place to prevent un-
authorized access.

Even if the system was disabled, local operating personnel can take over operation of the
facilities. This process is similar to what is done with loss of communication. The
mechanical systems, which are hard-wired and/or preset, can not operate outside of the
range established for their set point.
Protocols for testing new SCADA programs and changes to existing programs where the programming is significant, requires the testing to be done off-line. Only after successful testing is the new program loaded and commissioned onto the on-line system. Non-significant program addition or changes may be done real time.

The pipeline control system of one company is not interconnected to the pipeline control systems of other companies (i.e., the systems can communicate but operate independent of each other). This fact is consistent with Section 358.4(3)(ii) of the Federal Energy Regulatory Commission's regulations implementing Order No. 2004, which specifies that pipelines are prohibited from permitting the employees of its Energy Affiliates from having "access to the system control center or similar facilities use for transmission operations or reliability functions that differs in any way from the access available to other transmission customers." 18 C.F.R. Section 358.4(3)(ii) (2005). Thus, unlike the electric transmission system, there is no "National Grid" with interrelated control systems. Each pipeline is operated independently of any other pipeline and access into one will not affect any other.

Y2K
A tremendous amount of work was done by the gas pipeline industry before the new millennium in preparation for perceived threats to pipeline operations due to millennium date issues. Companies expended necessary resources to look at control systems for equipment, SCADA systems, compressor unit controllers, flow controllers and basically all other equipment and systems that had intelligent electronics. Companies developed processes to review these systems and equipment on a continual basis.

During this review, susceptibility to cyber threats was considered by transmission and distribution operators. Equipment was examined to confirm the hard-wire or mechanical set points could not be altered. Logic systems were tested, as were fail-safe protocols and vandalism potential. This review proved to the operator that their systems and equipment could not easily be compromised by logic failures or override attempts.

The Y2K scenarios were performed and these scenarios envisioned every type of failure known at that time, which may have a negative affect on the pipeline system. Where the scenario indicated a potential for failure, new protocols were developed or other actions were taken to correct the deficiency.

During this process, transmission companies and many large distribution companies practiced emergency procedures and communication failure protocols. They also reviewed the redundancies of their systems and made sure of the fail-safe operation of electronically controlled equipment. If they did not have Uninterrupted Power Supplies, and a need was determined, they were added. Companies made sure that they had back-up locations from which the pipeline could be operated. Companies also confirmed that manual operation was effective.
NATURAL GAS PIPELINE CONTROLLER FUNCTIONS

Transmission control operations involve the movement of product on behalf of shippers. Shippers nominate service on a given pipeline for a specified amount on a specified date. The control function manages the daily shipment of natural gas to meet the nomination. In order to perform this function, the controller manages compression, flow, storage, receipts and deliveries. The complexity of the function varies greatly from pipeline to pipeline and is dependent on the size of the operation, the amount of natural gas moved, the amount of compression, deliveries and receipts, storage and other factors.

Distribution control operations involve the movement of gas on behalf of the customer. The control function manages the pressure by maintaining minimum acceptable delivery pressure at key locations and at network end points and through storage facilities, liquefied natural gas facilities, propane-air plants and/or pressure regulator stations.

SCADA systems are used to aid in the operation of the pipelines that transport substantial quantities of gas to key delivery points in a system. Various data are gathered and transmitted to the SCADA computers. The controller monitors this data. In addition, parts of the system may be automated allowing the controller to control the system. This control ability is more typical for transmission operations and can involve the starting and stopping of compressor units, the adjustment of flow rates, the opening or closing of valves and pressure control. Although some compressor stations have remote capabilities, some may have stop but not start capabilities. Many stations are operated manually with instructions made to operators by the controller. Some valves, usually at the compressor stations, have remote control capabilities. Remote control on mainline valves is not common.

The SCADA system provides alarms, which are preset and represent deviations outside of expected parameters. The alarm screens are monitored constantly, and critical alarms require immediate and continuous actions. Non-critical alarms require action as determined by the controller.

The data collection and equipment control of the pipeline system is typically decentralized. The data from the operating equipment is captured by the remote terminal unit (RTU) or individual unit logic system that is located at pipeline field locations. This unit saves the data until queried by the SCADA system. The SCADA system supervises the RTU or individual unit logic system. The RTU or individual logic system contains the programming necessary to operate the piece of equipment. This programming cannot be over-ridden by the pipeline controller or the SCADA system, since it is either hard-wired or locally programmed.

The gas controller has no direct interaction (other than remote operation) with the mechanical devices and controls, which make up a pipeline system. These mechanical devices have their own limits hard-wired or mechanically set into the equipment. Compressors have individual logic systems with preset limits, preset shutdowns and separate over-pressure protection systems. Pipeline flow control units have internal logic
or mechanical components for pressure override set at MAOP and over-pressure protection as well.

The pipeline systems are completely capable of being operated independently with onsite control in lieu of central control.

Transmission pipelines are open access pipelines in that the operator is required by tariff to receive gas at a given receipt point and deliver an equivalent amount of gas at a specified delivery point. The pipeline may stipulate a receipt and delivery pressure but is required to determine and operate at or below the MAOP\(^9\). The MAOP is determined by the pipeline safety regulations. Pipeline operators are required to prevent the over-pressure of their pipeline system\(^{10}\). Correspondingly, pipeline system operators who receive natural gas from other pipeline system operators have their own over-pressure protection\(^{11}\).

The gas distribution company or direct customer is provided with a tap to the transmission pipeline where it receives the gas. The gas is distributed within the service areas at various pressures to the customer. The pressure in the high pressure and low-pressure distribution piping is operated at or below the MAOP. Again, this MAOP is determined by the pipeline safety regulations. Distribution system operators are required to prevent the over-pressure of their own distribution pipeline systems.

The type of supplier and customer varies significantly as do volume and pressure requirements. A large electric producer may suddenly turn on a generator and take massive volumes of gas over short periods of times causing significant pressure reductions in the transmission or distribution pipeline. Other customers may draw small volumes over long periods of time. Weather, demand, maintenance, and many other factors also affect the operation of the pipeline systems, making each system unique and requiring specific knowledge and experience of the gas controller.

Given this, the gas pipeline system is inherently designed to virtually protect itself regardless of controller intervention. If there is no action, MAOP remains protected, in that units will shut themselves down and deliveries made if they can be safely made -- all in the short term. Though alarms will annunciate and a response will be required, the controller response does not need to be instantaneous due to the pipeline's ability to pack gas and due to the compressibility of the gas."

Even with safety mechanisms inherent to system design, companies institute safeguards within the gas control function. Many companies have more than one person on shift. Smaller companies with one controller may have other shift personnel at the location or a

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\(^9\) 49 CFR §192.619 Maximum allowable operating pressure: Steel or plastic pipelines.


\(^{11}\) An PHMSA interpretation states that operators are responsible for over-pressure protection of their own facilities.
dead man alarm. This alarm requires resetting at predetermined intervals such as every 15 minutes. If the alarm is not satisfied, the system calls the on-call supervisor. The supervisor then calls the gas controller and if the latter cannot be reached, either sends security and/or goes in to the center to check on the individual.

Reliability of Service
Interviews with gas controllers show that though the potential exists to interrupt transmission service to a gas distribution system, large volume facility or other customers, such potential is minimized by the number of safeguards built into the pipeline control operation. Again, the compressibility of natural gas provides a buffer of time in which the safeguards can be initiated.

Recognition of a Possible Incident
The controller is most likely the focal point of communication at the time when a possible incident has occurred. The controller can receive information about a potential incident via the SCADA system, pipeline operation personnel, the public or through the media. In some operator’s systems, especially gas distribution companies with many customers have isolated the controller from the public interaction and this function is performed by specialized personnel qualified to deal with the public. Once that a potential incident has been recognized, the controller has the responsibility to notify operating personnel about a potential incident so the incident can be confirmed.

Transmission Pipelines
After a pipeline incident or other significant event occurs, the gas controller may or may not be immediately aware of the situation based on the monitoring of alarms and system parameters. However, it is most likely that the controller will see a drop in pressure or an increase in flow. As dictated by the procedures for the operation, this action may precipitate a first response by the controller.

Each pipeline company has in place specific protocols for dealing with this situation. These protocols vary greatly and depend on many factors including pipeline configuration, number of parallel lines, whether bypasses are open or closed, customer’s demands, etc. The steps the controller takes are therefore specific to the location, company protocols and the impact of the incident.

What happens during a rupture or other event is the immediate decompression of the pipeline near the rupture or cut. Within a few seconds, the pressure drops at affected site and the gas vents into the air. The impact signature is very limited for gas pipelines and can range from a few feet up to several hundred feet; depending on pressure at the time of failure and pipeline diameter. Studies show that nearly all of the damage caused by a pipeline failure is done within the first couple of minutes.

For transmission operation, after in initial rupture or event, the pressure drops quickly. Downstream, with no gas supply, the pressure will drop over time until the downstream compressor station begins to see a drop in suction pressure. The controller can see this pressure drop as he/she monitors the system. If the controller fails to notice the drop, a
low pressure suction alarm will annunciate. If no action is taken, the compressors will shutdown due to loss of suction pressure.

Upstream of the rupture or event, the pressure will drop over time until the upstream compressor station begins to see a drop in discharge pressure. The station will then attempt to maintain pressure and flow by compressing more gas. The pressure drop and flow change will be seen by the controller and an alarm will annunciate when preset limits are reached.

Following actions to isolate the ruptured pipeline section, the gas will continue to vent from the rupture until the pressure in the isolated section falls to near atmospheric pressure.

Distribution Pipelines
For distribution operation, after the initial event, the pressure may or may not drop quickly and often the pressure is maintained until a repair can be made. The event signature for distribution operations is comparatively small and can be safely contained until the repair is made. This action is often necessary in order to avoid loss of service to large numbers of customers.

The operation by the controller under these situations is limited by company policy. A call out to the field operating location is made in order to have a person verify the parameters of the situation before action is taken. Company policy may dictate that the controller will not take action until confirmation of the rupture or event is received. The company in this instance would be trying to balance management of the rupture or event against management of the loss of service.

Confirmation may come in many forms. It may come from the dispatched field person. It may come from a property owner or an emergency response agency. Companies provide information on emergency response to emergency response agencies just for this situation. The same is true for the public education programs that companies conduct, which provides information on recognizing and reporting an emergency.

MANAGING ABNORMAL OPERATIONS

If there is the possibility of an incident, the pipeline controller will deem these situations to be abnormal operations, and standard operating procedures and processes are in place to recognize and react to these situations.

Preparing for Abnormal Situations
49 CFR Part 192.605 requires pipeline operators to have procedures in place for recognizing and responding to abnormal operations. Abnormal operations include inadvertent operation of a valve, loss of communication, exceeding design limits and operation of a safety valve. The procedures apply to all company personnel including the pipeline controllers.
Control room operations include provisions for operating with loss of power or communications. Control systems have emergency backup power, where there is an established need. In addition, there are provisions for either emergency operation offsite and/or disaster recovery operations at another location. These situations are practiced on a routine basis for the more complex pipeline systems and helps ensure continuity of operation in the event of a natural or manmade disaster.

Operators plan for loss of communication by ensuring redundancy in communication equipment. For example, the operators have not only leased telephone lines, but also have cell phones, satellite phones, and/or radio which allows continued operation without main communication. The assets themselves can be operated locally and voice communication allows necessary control. The equipment is also designed for fail-safe operation. In all cases, the equipment operates based on the last set point (when controlled by the SCADA system) and the equipment cannot exceed its hard-wired limits or override limits.

All companies interviewed have two 12-hour shifts, three 8-hour shifts, or shifts of duration that are appropriate for the company and which work the best for the company. This also provides for at least half of the controllers to be out of the control room at any one time. This in turn aids in emergency operations and disaster recovery as well as protecting the work force. Controllers are given ample opportunity for rest between shifts.

**Crisis Communication**

The pipeline controller’s response to a pipeline incident or other significant event is managed through a pre-existing procedure typically titled “Crisis Communication”. In the event of a significant pipeline event, company personnel and management are advised of the situation in order for decisions to be made. The decision to shutdown a pipeline may be made by the controller based on written procedures or may not be made by the pipeline controller, but rather by designated company management personnel.

In addition to the notification and response of company personnel, various federal, state and local officials and emergency responders may be notified of the event.

Mock drills or table-top exercises are typically conducted by transmission and distribution operators on a routine basis in order to confirm the processes and procedures while providing training to the controllers and other operations personnel and their management.

**REVIEW OF PIPELINE CONTROLLER RESPONSIBILITIES BY OTHER GROUPS**

The subject of gas controller qualification is a constant item of discussion at the AGA Gas Controller meetings and that group contributed significantly to this white paper. ASME is just completing a standard on operator qualifications and has included what they feel are the responsibilities of a pipeline controller, which correlate with the findings during the development of this white paper.
Draft Operator Qualification Standard, ASME B31Q
The pipeline industry along with PHMSA and other interested parties are developing a standard for qualifying pipeline operations personnel. This standard includes provisions for qualification of gas controllers. This standard was developed under the auspices of the American Society of Mechanical Engineers (ASME). As a result of this work, over a period of two years, this group has identified the same operations that have been addressed and summarized in this White Paper.

The following is a list of System Control Center Operations Tasks from the draft standard:

Task Guidance:
This task includes the remote operation of a gas pipeline, (e.g. monitor operating parameters, notifications, remotely adjusting and maintaining pressure, remotely starting and stopping compressors, etc.)
1. Identify Requirements
2. Monitor system operation
3. Determine if action is needed to maintain or adjust pressure
4. Complete required notifications of pressure adjustment
5. Adjust or maintain pressure by remotely starting, stopping or changing the operating parameters of compressors
6. Adjust or maintain pressure remotely by changing pressure regulating set points
7. Adjust or maintain pressure by remotely operating valves
8. Adjust or maintain pressure by directing manual operation of compressors, pressure regulating equipment and valves
9. Verify pressure adjustment to bring the system within required operating parameters
10. Recognize and react to Abnormal Operating Conditions
11. If required, complete documentation

SUMMARY
This White Paper relied on the input from a large number of operators of gas transmission and distribution facilities. The information presented is representative of the pipeline industry.

This document explained the operation of gas pipelines from the control standpoint and shows that control personnel can not cause a pipeline incident; that they can not cause the impact from an incident to be increased due to action or inaction; and that their role in recognizing and reacting to a potential pipeline incident, is limited until confirmation of a pipeline incident is achieved and the impact of loss of service is weighed against the impact from the failure, by other involved personnel.
The pipeline system is designed for fail-safe operation and has sufficient redundancy or back up, to prevent failures. There are always at least two devices, one to control pressure or flow and one to prevent over-pressure of the pipeline. Bypass of the control equipment requires hands-on operation and cannot be operated by the gas controller from the control room.

What the gas controller can do and has demonstrated ability to do is to respond to alarms that indicate an abnormal operation of the pipeline system.

Gas control personnel do have an effect on the business operation of the pipeline system. Their actions, or inactions, have the potential to impact the reliability of service; however, their response cannot have a significant impact of pipeline safety. Training and qualification can help to mitigate this potential.
## Appendix A

### Transmission Participant Companies

<table>
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<tr>
<th>Company</th>
<th>Miles of Transmission</th>
<th>System Type</th>
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<tbody>
<tr>
<td>Panhandle Eastern</td>
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<td>Long Haul</td>
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<tr>
<td>Tennessee Gas</td>
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<td>ANR Pipeline</td>
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<tr>
<td>Gulf South Pipeline</td>
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<td>Long Haul</td>
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<td>Market</td>
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<tr>
<td>Florida Gas</td>
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<td>Market</td>
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<td>Dominion (DTI)</td>
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<td>Grid</td>
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<td>Northern Natural Gas</td>
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<td>CenterPoint Energy</td>
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<td>Texas Gas</td>
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<td>Long Haul</td>
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<td>National Fuel Gas</td>
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<td>Transco</td>
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<td>Columbia Gas</td>
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<td>Grid</td>
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<td>Columbia Gulf</td>
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<td>Long Haul</td>
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<tr>
<td>MichCon (DTE)</td>
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<tr>
<td>Texas Eastern</td>
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<td>Algonquin</td>
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<td>East Tennessee</td>
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<td>Colorado Interstate</td>
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<td>El Paso Natural Gas</td>
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<td>Trunkline Gas</td>
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<td>Pacific Gas and Electric</td>
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<td>Iroquois</td>
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</tr>
<tr>
<td>Southwest Gas</td>
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<td>Market</td>
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**Total**             | **140,353**            |             |
### Appendix B
Distribution Participant Companies

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<thead>
<tr>
<th>Company</th>
<th>Miles of Distribution Main</th>
<th>Number Customers</th>
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<tr>
<td>Delmarva Power</td>
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<td>PG&amp;E</td>
<td>40,000</td>
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<td>PSE&amp;G</td>
<td>17,250</td>
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<td>UGI</td>
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<td>Dominion Gas Delivery</td>
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<td>MichCon</td>
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<tr>
<td>BG&amp;E</td>
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<tr>
<td>XCEL</td>
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<td>New Jersey Natural</td>
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<td>Atmos</td>
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<tr>
<td>South Jersey Gas</td>
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<td>313,000</td>
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<tr>
<td>Southwest Gas</td>
<td>25,427</td>
<td>1,695,000</td>
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<tr>
<td>Puget Sound</td>
<td>11,000</td>
<td>650,000</td>
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<tr>
<td>NiSouuce</td>
<td>40,842</td>
<td>3,200,000</td>
</tr>
<tr>
<td>Consumers Energy</td>
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<td><strong>Total</strong></td>
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<td><strong>21,148,580</strong></td>
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