Comments on Pipeline and Hazardous Materials Safety Administration's Pipeline Safety: Gas Pipeline Regulatory Reform

PHMSA 2018-0046-0010

and PHMSA 2016-0136 (GAPAC)

and

Relevant Executive Orders Consistent with Regulatory Reform

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Submitted by

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Introduction/Background

Regulatory reform measures normally appeal a business consultant to many industries in the energy sector—either for electric utilities or as industrial users of natural gas. Nothing in these comments should be construed to oppose natural gas or to seek to maintain excessive regulations. However, there are aspects of the natural gas transmission, distribution and gathering line segments infrastructure that are not adequately regulated for the reliance on natural gas. Reliance upon natural gas needs serious consideration as there are significant gaps between where DOE, FERC and NERC and PHMSA currently evaluate and collect data. Revising the reportable threshold to fewer reportable events at PHMSA will only make the reliability gap worse. Those reporting gaps and consequences of these gaps are identified in the comments for PHMSA, DOE, FERC and NERC to consider for finding solutions to bulk electric, non-bulk electric and industrial users of natural gas.

The comments are submitted based upon commenter's 20 years' experience working for the electric sector, seven years for the oil and gas sector (including pipeline industry) and for manufacturers who use natural gas as both a fuel source and a commodity to make other products. Views and recommendations are based upon experience, work observation and the ability to see several sides of the issues from transportation to commodity user to make products and to electric utilities and manufacturers reliant upon natural gas as a fuel source. The comments do not claim to offer opinions reflecting former employers. Nor are the comments a gimmick to oppose natural gas as a fuel for electric utility and industrial community that reduces many conventional pollutants—including CO_2. There is no question that natural gas is a far superior commodity to coal but there are some complexities in reliability because the gas cannot be stored on site. These complexities are not insurmountable. But they require more information on how gas is used and about the gas transmission (and distribution) system encounters curtailment events.

The comments are also offered in response to PHMSA's July 23 Gas Pipeline Advisory Committee (GPAC) where a number of topics were brought up for discussion. These comments are presented together because the issues are brough up in both dockets. Docket 2018-20046-0010 pertains to a few questions asked about regulatory reform (and commenter's observation about what should also be considered under regulatory reform) and Docket 2016-0136 pertaining to cost-benefit analysis and whether or not gathering lines should be addressed. The question whether to regulate and how to regulate gathering lines (especially >11.75") has languished before PHMSA, the states and the GPAC for too long.

Regulatory Reform

Regulatory reform can be a very productive process when regulations are poorly designed, antiquated or lack adequate current safety, scientific, technical or economic data. These comments are to help PHMSA address opportunities to make narrow, surgical improvements to gas pipeline safety regulations. These comments are not designed to give blanket endorsement or blanket opposition to regulatory reform. There are a number of aspects to the proposed rule which stretch beyond commenter's competence. The recommendations are made to be undertaking under existing regulatory authority and under Executive Order authority. (The recommendations do not reflect any possible revisions to the PIPES Act currently underway in Congress).

Recommendations

1. **The importance of retaining the existing $50,000 threshold for reportable event as defined under Section 191.3.** There have been explosions and non-explosion damages to properties that exceed $50,000. While $50,000 may have seemed like a high reportable threshold in 1984, often the placement of natural gas pipeline and compressor locations were very distant from homes, small businesses, and cities. As the U. S. has become more urban and populations more dense, natural gas pipelines and compressor stations may, during fires, explosions, or other events could cause partial damage to $50,000 in property that merit reporting to PHMSA. Commenter recognizes this reporting costs gas producers/gas pipeline owner/operator and contractors to report on damages of $50,000 (excluding the cost of natural gas) is a regulatory cost. But it is the cost of doing business in a critical, necessary and dangerous business. Other industries are not exempt from comparable reporting to federal, state or local health and safety agencies simply because a large percentage of one segment (gathering lines) are small businesses. Most intrastate pipelines are owned/operated by municipal governments and private industry. While some are very small communities they should be regulated for safety. Damage to a primary home, vacation home, cabin, or to a small commercial business structure, agricultural business with a real estate value is still important if it is damaged and it is valued at >$50,000. It is not needed to increase the reportable level to $122,000 simply because of the inflation of the 1984 reportable level. A damaged or lost $50,000 structure or capital equipment can be a major business investment even if might seem less significant to a multimillion-dollar pipeline project. Those business investments should not have to obtain special insurance that covers lost business due to a natural gas leak, force majeure or losses due to extreme spikes in natural gas purchased on market during curtailment. As seen after the 2015 Aliso Canyon gas leak, many of the thousands of businesses near Aliso Canyon were not able to get reimbursement from either their electric utility that owned Aliso Canyon nor from their private insurance carriers because the contracts said nothing about a natural gas leak/repair creating inability to serve customers[1]. While Aliso Canyon may have been a reportable event to the state and PHMSA- those businesses received no compensation for their lost business when the gas storage well leaked. *The comments include many non-Aliso real world cases and the economic impacts under Recommendation 3 (pages 3-8).*
2. **PHMSA's Incident Report-Gas Distribution System form and electronic reporting should make incidents/accident more clear**. Reporting should include whether industrials and power sector were notified of disruptive event (and subsequent curtailment) and by what length of time (minutes or hours). The form should allow the gas provider to state that re-direct natural gas at full contracted capacity to the customer through reverse flow or through alternative parties. Commenter recognizes that industrial natural gas processors might not want information in these PHMSA forms/reports that can be used by competitors (such as deducing gas throughput in plastics manufacturing etc.). No one wants PHMSA safety reports to be used by domestic or foreign competitors to conduct reverse engineering for gain. <u>But the power and industrial customers should have a way to determine during contract negotiations whether the company they wish to purchase gas from has a sound and reliable safety program</u>. These are legitimate

[1] Article on duty to care https://www.courthousenews.com/businesses-near-methane-leak-cant-sue-for-lost-profits/

requests given the number of force majeure or curtailment events and accidents over the last few years. **This argument is all the more critical using PHMSA's own analysis that all the major pipeline rupture accidents reported in the last ten years took >55-minute time between the event, contacting state officials, PHMSA and emergency responders. A 55-minute response time is significant for some industrial processors of natural gas.** PHMSA should call for comments on these issues in a separate more comprehensive call for comments given its own analysis that 10 years of experience demonstrate a >55-minute time.

For example, a natural gas processing client, making a solid commercial commodity, had less than a 45-minute notice for curtailment. The company's manufacturing process involves transforming natural gas into a liquid and then into a solid product. The manufacturing process is 24-7 and operates virtually 365 days a year due to the complexity of the processing. The processing is more like a chemical or refining process and, as a result, it normally remains in operation almost 345 days year. When the 45-minute notice occurred **the manufacturing, company encountered a force majeure shut down that damaged or ruined $300 million in replacing the damaged manufacturing equipment**. For confidentiality reasons I am not allowed to name the company or describe its product line. But a $300 million dollar capital investment due to a natural gas curtailment is significant and not to be dismissed as a small secondary effect. Currently the PHMSA reporting system has no way of capturing this since the pipeline company did not know about the value of the lost manufacturing equipment. Disclosure of significant curtailments might help other industrial users and electric utilities to know about the reliability and safety accountability of the gas transmission provider when signing long-term contracts. While this is not PHMSA's responsibility it is a co-benefit to the

3. **PHMSA should expand its Cost and Benefit Analysis to look at the benefits to society for the benefits of the new regulations (both for new and existing pipelines and compressor stations) when those safety measures reduce risks of force majeure or curtailment events.** Currently the electric utility sector uses approximately 34% natural gas for fuel[2]. That number will increase when counting back up fuel for intermittent renewables (solar, wind, when hydro needs auxiliary fuel) and black start for nuclear power.

   North American Electric Reliability Corporation (NERC), was authorized by FERC (and Congress) to identify possible risks to bulk electric reliability. NERC's Table 1.3 (below) from its 2017 reliability study[3] points out the locations where the approximately **300 bulk electric utilities have natural gas-fired generators with reliance upon ONE natural gas provider. Another 176 power operators are heavily reliant upon only one "trunk" gas pipeline serving the region where their power plants are located.** NERC's study shows that certain regions are more at risk than others such as the SE, Florida (which also has a fully subscribed gas pipeline serving all power plants with no secondary or auxiliary pipeline system), and Southern California (where <u>two separate gas pipelines ruptured two years ago and still not in service[4]</u>).

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[2] DOE's EIA data, 2020

[3] Commenter Theresa Pugh worked as an unpaid volunteer on the NERC committee's gas reliability study

[4] Pipelines 235 and 4000 in Southern California

This means that approximately 30% of the gas-fired power plants or approximately 158,781 MW capacity (including some Canadian generators) do not have a secondary gas supply serving that power plant. This means a considerable percentage (approximately 10 percent) of the U. S. electrical supply (perhaps larger if including non-bulk electric) that do not have a duplicative source of natural gas if the primary pipeline is curtailed. To make matters more interesting there are also 174 gas-fired power plants that do not have a secondary trunk line (See NERC's Table 1.3 below). *(This is by contrast to most power plants in the 1980-early 2000s that had two rail or barge transport methods and coal storage on site).* It is true that some natural gas pipelines have a reverse flow or other methods to move gas (which commenter heartily endorses). But not all gas pipelines can reverse flow in sufficient quantity by redirecting gas to avoid curtailments when the rupture is on another pipeline. Nor can the power sector store natural gas adequately for a power plant of 500 MW through gas line packing.

It should also be pointed out that NERC's report is a conservative estimate of the problem because NERC only looks at the electric utilities that have a role in bulk-electricity. So, a 100 MW utility in Iowa, or 500 gas-fired power plant in the lower Midwest might not even be covered by the NERC report if they are served by one single pipeline or one single compressor station with no redirection to obtain natural gas during a curtailment. While that plant might not be a problem for bulk electric—it still may be a problem for local businesses and electric customers. Further, more power plants that were coal-fired or nuclear power (or occasionally hydro with aged dams) have retired since 2017 when NERC issued this report. (*This is not a criticism of NERC's report- it is merely an observation that three years has passed since NERC produced this report with many changes in the electric generation portfolio).*

Table 1.3: Natural Gas Supply Characteristics by Area

Region	Number of Generators with One Connection	Generation Capacity with One Connection (MW)	Number of Major Supply "Trunk" Lines Serving Area
Northwest	16	4,963	24
Southern California and Arizona	20	11,430	13
East Texas, Louisiana, and Oklahoma	40	17,965	60
Southeast	68	46,124	35
Florida	38	31,049	7
Middle Atlantic	22	12,244	9
New England	35	13,103	6
Northeast	49	21,903	20

Source: NERC's Single Point of Disruption Study, Nov., 2017

PHMSA's safety protection obligations mean that now with more gas-fired utilities and manufacturers that PHMSA should consider the benefits to protecting critical industries such as electric utilities and "just in time manufacturing" where a loss of natural gas causes

economic hardship. As documented in chart on page 7, there were many businesses that faced severe economic hardship when forced to purchase natural gas to compensate for the gas not delivered under firm contracts after the 2018 Enbridge St. George explosion (near Sumas Pass). Subsequent to the pipeline repair (on sixth day) the Canadian National Energy Board reduced the pipeline (and compressor station) volume or product by 20% for almost five months during its root cause investigation. Commenter has no complaint about the common safety decision to reduce pipeline and compressor station during a safety investigation. But there can be tremendously costly consequences to gas-fired power plant or industrial user when pipelines are out of service for four or five months (due to an explosion, construction equipment, installation errors and over pressurization). PHMSA has ignored these secondary consequences despite being provided information on how these events can harm industries that lose their gas. There is no mention in PHMSA's Preliminary Regulatory Impact Analysis (PHMSA 2018-0010) on these broader impacts although the PHMSA staff described having "heard from industry" and mentioned American Forest & Paper Association[5] twice during the July 23, 2020 GPAC meeting.

In the case of the Enbridge 2018 explosion, the region would not have maintained the power to support 700,000 residential and other smaller commercial businesses without Fortis Energy's[6] successful Demand Side Management (DSM) program. Fortunately, Fortis has a well-established DSM program. Not all electric utilities can rely upon almost a million people to reduce usage for almost a week. Also fortunate was that Fortis and their customers faced cold temperatures but not nearly as cold as in a far colder province (Saskatchewan, New Brunswick or far eastern Canada) or comparable U. S. states reliant upon natural gas during extreme winter cold weather.

Canada's small commercial nursery (commercial planting) owners in far western provinces faced such extreme costs in Jan. 2019 following the Enbridge outage. Many opted to completely suspended winter nursery plantings due to the 200% increase in the cost of natural gas during that winter/early spring planting season. (Often Canadian agriculture businesses must begin plantings earlier due to extreme winter cold and shorter spring growing season than its competitors in the U. S.). In western U. S. the Enbridge accident caused operational changes at several U. S. electric utilities including, Avista Corp. and Puget Sound Energy which asked U. S. customers to curtail usage for six days. Many of these electric companies (with both natural gas and hydro power) had to curtail and ask for customers to lower winter heat thermostats to 55 or 60 degrees for a week.

While it is not PHMSA's regulatory obligations to be concerned with Canadian agricultural businesses these are many examples from four or five curtailments in 2018-2019 that illustrate why the PHMSA "benefits" analysis should consider the reliability of gas-powered electricity and gas sold to industrial consumers or processors.

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[5] These comments do not reflect all of the views held by AF&PA but AF&PA is a client of Theresa Pugh Consulting, LLC.

[6] https://financialpost.com/commodities/energy/gasoline-prices-soar-in-northwest-on-canada-gas-pipe-rupture

These examples range from the Northwestern states (and Canadian provinces), Michigan, Tennessee and the NERC graph from its 2017 study shows the many other locations that might have bulk electric reliability issues.

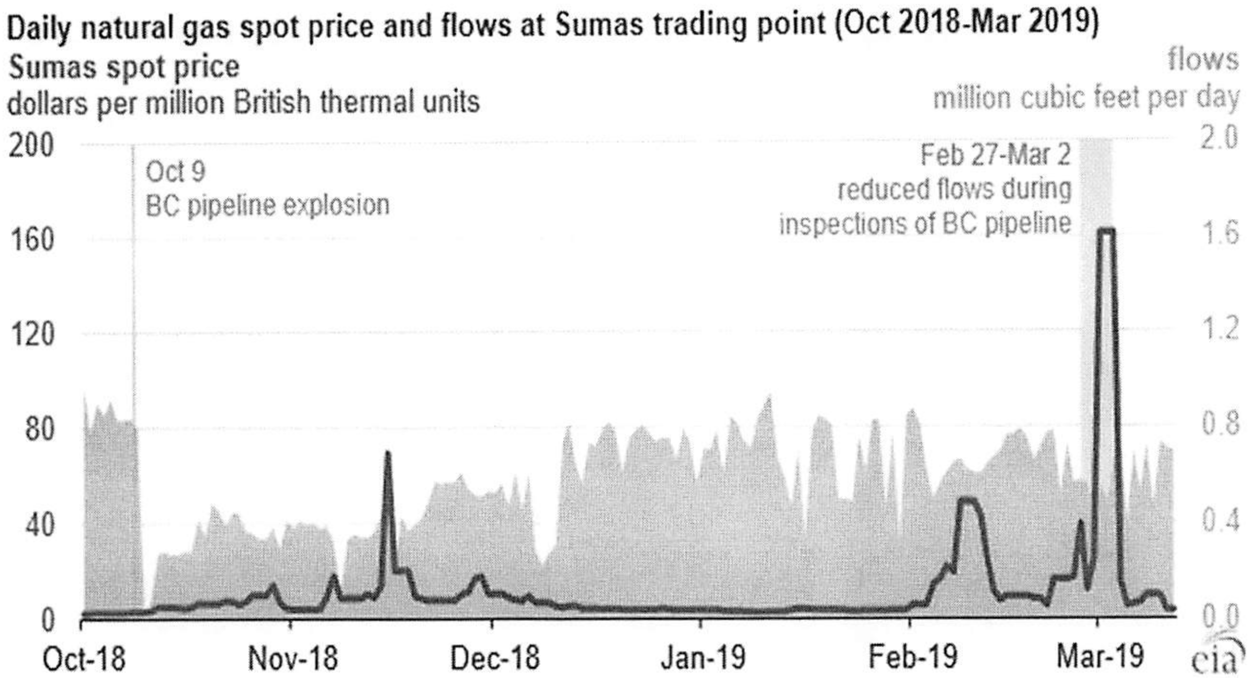
Reliability of natural gas for power sector and industrials is based upon pipeline and compressor station safety:

Commenter observes that no one has researched this issue adequately on a more granular level except Carnegie Mellon's research by Gerad Freeman, Jay Apt and Michael Dworkin. That Carnegie Mellon study merits your review[7] (and review by FERC and NERC). The Carnegie Mellon team have made excellent observations about how many non-reportable events have happened that have caused service or gas disruptions to gas-fired utilities and to their customers. A copy of their excellent paper is provided in Part II of Comments. They would not have been able to document these events without FOIA to obtain information. The paper points out the many pipeline outages and pressure drops that have resulted in economic disruptions. Freeman, Apt and Dworkin point out that one in five gas-fired power plants experienced natural gas failures between 2012 and 2016—when as a nation we were less reliant upon natural gas as we are today. (Commenter notes what their paper does not mention in detail is that only a handful of gas-fired power plants have a secondary or dual fuel permit allowing them to use oil. While some power plants have a **dual fuel** permit it is antiquated as the power plant no longer has adequate space for oil tanks given the space used for other pollution control devices such multi-story baghouses (that may now not be needed as more coal-plants have been adapted to burn gas). Some power plants did not maintain compliance with (SPCC[8]) anti oil spill regulations sufficient to store oil on site. Most commonly, electric utilities in ozone non-attainment areas (smog) cannot burn oil during summer months (May through September) because of the added pollution unless a governor has declared a state of emergency for hurricanes, floods, etc.

Public information on cost differential for western natural gas users from Enbridge when market prices spiked for five sustained months:

[7] Study provided as Part II of comments

[8] EPA's Spill Prevention Countermeasures Control regulations



Michigan's January 2019 Consumers Energy Macomb County compressor station fire:

In early Jan. 2019 Consumer's Energy Utility dispatched a crew to conduct maintenance assignment at the Macomb County compressor station. A crew member made a mistake causing the compressor station to catch on fire in early January week during an extremely cold Polar Vortex weather event. The compressor station was out of service for almost a week. During this time more than 100 manufacturing companies in Michigan were unable to obtain electricity (or natural gas). These companies included 80 contractors or suppliers to the U. S. auto industry, two chemical plants and one microchip manufacturing company. The auto industry (and their suppliers) announced they would pay for their workers to get an additional week of pay when they could not operate (following a week of paid leave during Christmas holidays as is common in auto industry). Those businesses lost both the ability to make product on time and paid for their employees with lost manufacturing time. While the auto industry predicted they could make up for the manufacturing time by adding a third shift on the week following the return of service for Macomb County compressor station—not all of these 100 employers were so fortunate.

This commenter could not find on the current version of PHMSA's Incident Report- Gas Distribution System any requirement for the incident report to indicate whether there are impacts on major gas customers such as natural gas-fired power plants with no secondary source of gas during curtailment by the provider or for 24-7 manufacturers who might not have the ability to shut off manufacturing operations without significant impacts to their manufacturing equipment. Commenter recommends that PHMSA's reportable events forms (electronic and paper) require that major customers be listed on the forms. The commenter understands that some natural gas usage by a manufacturing customer might contain confidential business information (CBI). For example, a batch plastics manufacturer who would not want its competitors to know what the volume of its natural gas commodity is for "back engineering" by competitors.) But it would be useful for the manufacturing and electric utility customers to be able to review the PHMSA Gas Distribution System data by name of companies or region to see which companies have had the poorest performance and the best performance when negotiating natural gas contracts. It would also be helpful if in questions A14-18 and section D can question could whether "Was any continuous operation manufacturing plant or natural-gas fired power plant customer notified within 1 hour of incident?" with a Yes, No or Not Applicable (NA) check box. Additionally, form submittal should provide timely information whether the industrial gas user or natural gas-fired utility was able to obtain alternative gas routing or alternative gas at full or normal use (under firm contract).

Michigan's PUC conducted an analysis on the 2019 compressor station fire and gas curtailment and it is located at https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf. Regrettably the American Petroleum Institute's spokesperson described the events as "that's the market functioning in precisely the way it should"[9]. Perhaps API's speaker naively believed that only bulk electric mattered but the reality is that neither the market nor the infrastructure worked well when 100 factories did not have sufficient natural gas to operate after a compressor station caught fire. Commenter does not believe API would have described this as a market success if the PHMSA reporting system had shown that 100 factories did not have access to Consumer's natural gas following the compressor station fire. While there were some other Polar Vortex related weather events in PSEG's nuclear plant (ice clogged screen) that generally speaking the Jan. 2019 midwestern gas shortage was caused due to extreme weather when Consumer's Energy had a compressor station fire. Consumer's had no other ways to move natural gas to those 100 industrial customers for six days. MISO commented that the grid remained stable—but their responsibility was not to watch for natural gas to serve 100 Michigan factories lost gas for six days[10]. **Again, there are gaps in what we know about the natural gas infrastructure system during both weather events, curtailment events, and what happens on the non-bulk level for power plants. Having better PHMSA data is a great start. Perhaps FERC, DOE, EIA, NAESB and NERC can also find methods to improve data collection and analysis. DOE and FERC can use data and allorhythmia developed by Argonne National Laboratory.**

4. **It is time to regulate gathering lines**: The nation's 400,000 miles of gathering lines have not been regulated by many state safety regulatory agencies. For perhaps ten years the industry has filed comments saying that the regulations did not justify the costs. Or the segment asked for more safety studies as was discussed at the July 23, 2020 Gas Pipeline Advisory Committee (GPAC) online meeting. Perhaps if the majority of the nation's gathering lines were only in the rural and low population density of Texas' Permian Basin this reluctance to regulate would be understandable. But times and circumstances have greatly changed with shale oil-gas production in more densely populated states.

   For decades the arguments offered, sometimes legitimate, was that the gathering lines were in remote or rural locations with small volumes and little or no risk for pipeline failure. But this is no longer true. In the last ten years more than 83% of new (shale) oil and natural gas has been brought to market by small producers. Commenter can understand the need to not require extensive and expensive safety measures on small gathering pipelines located in rural locations that might strangle off new natural gas production.

[9] E and E News https://www.eenews.net/stories/1060119619
[10] Ibid

Many gathering lines, perhaps abandoned by prior owners who went out of business or filed for bankruptcy are left with often little or no regulatory coverage. In some states there are no regulatory agencies to monitor those abandoned pipelines. One cannot dismiss, particularly in the current economic decline that there will be more bankruptcies in the small or independent producer companies. Even in good times very small producers are short on cash. It is wrong for PHMSA to delay regulatory actions because of reliance on faulty cost-benefit analysis or a philosophical belief that these gathering lines are regulated adequately by local agencies. In most states gathering lines are not regulated by state pipeline safety agencies. That authority has often been, like prior gas storage, where too much deference was given to state oil/gas councils or quasi industry organization. The 2017-2018 deaths in Colorado and Texas are proof that these gathering lines need more regulatory oversight and the regulations should demand better compliance. **In particular the larger gathering lines in new shale gas production that functioned more like gas transmission pipelines should be regulated**. Typically, these are >11.75" diameter pipelines.

Commenter is a fifth generation Texan and a descendent of two generations of very small oil/gas producers with active (though declining) production. Commenter realizes requiring that gathering lines be regulated will increase production costs. But if a producer cannot afford to manage safety obligations perhaps the producer should not be in the natural resource extraction industry. Energy Now[11] and Bloomberg Energy reports that in the last three months alone there have been 75 bankruptcy filings with companies leaving significant liabilities of at least $50 million. Another 892 companies have demonstrated distressed bonds according to Bloomberg. The LA Times reported in May 2020 that Rystad Energy predicts $38 billion more in write-offs among top producers (including larger oil and gas companies and smaller independents). Given the dramatic increase in production and midstream segment bankruptcies, it is important that the gathering segment be required to design and build pipelines leaving no safety problems-whether operational or abandoned.

It is time for the "after you Gaston, oh no after you Alphonse" attitude about delay of state or PHMSA regulatory actions to change. PHMSA should not defer to state agencies to regulate

[11] Energy Now/Bloomberg Energy, July 1, 2020

gathering lines while those states wait for PHMSA to take action. A review of comments submitted by the gathering industry over the last ten years the industry has continually called for more time, more research and more delays- not even focusing on the larger pipelines where consensus might be easier to reach.

According to a Texas Tribune article[12], published again by E & E News, March 7, 2019, a gathering line located near Midland killed a child. Two men were killed in Colorado from abandoned gathering lines that no one knew were in proximity to homes that had no natural gas service. In the case of the Texas death included significant hospitalization of other family members of the family near Midland, no PHMSA investigator was sent because this segment of the industry was not included in Federal law. Nor, according to the Texas Tribune, was the event reported to PHMSA. In the case of the Texas tragedy, the company was not fined for failure to address the pipeline's corrosion problems. Enforcement should be expanded to inculcate adherence to safety measures. Adherence to safety regulations should not only be reliant upon civil litigation risks. These accidents are not only tragic but they harm the reputation of the industry.

In neighboring Colorado, two men were killed in 2017 when the men were working on a home, with methane from an abandoned gas pipeline was unknown. The home, owned by one of the victims, was not connected to the natural gas infrastructure that caused the accident. But during home repair the men triggered an explosion of an unmarked, uncapped, and unknown pipeline leaking methane. The homeowner had been told the closest natural gas pipeline was located 1 mile away. An uncapped one-inch pipeline leaking methane and killed the two men. Unknown to the state or prior owners or the family of the deceased was an unseen oil well at the property's fence line. Still after two years later the state of Colorado does not have a comprehensive map showing abandoned and existing gas pipelines and other oil/gas sources that can cause public safety risks. While the current oil/gas companies have collected information about 6,522 miles according to the Colorado Oil and Gas Commission[13]. Not all explosions and system failure events are reported. According to Denver Post, there were 35 reported pipeline 'incidents' or 'accidents' from leaking valves, ruptured seals, etc. And some of these were caused by third parties during construction or repairs. Congressional Research Service contends there are approximately 12 deaths and 32 events per year on pipelines or compressor stations that are reported.

While approximately 175,000 miles of the industry's 450,000 miles of gathering lines are in Texas, it is important for PHMSA to regulate. Entirely too many gas users might be affected as well as residences located near unknown or abandoned gathering lines. Even if these gathering lines are in Texas or Pennsylvania, there is no way to predict that the land will not be future tragedy for a family if gathering lines are not regulated. Texas has moved from being the fifth largest populated state to the second largest state in less than three decades. If the water

[12] https://www.texastribune.org/2019/03/07/oil-gas-deadly-pipelines-no-rules/

[13] Denver Post, October 27, 2019

shortage problems in west Texas were resolved (admittedly a heavy lift), that region of the state might become a more densely populated region.

Commenter believes that all new gathering lines >11.75 inches should have all of the same safety measures imposed upon them as larger transmission pipelines due to more complex shale-gas production wells co-located for many other efficiencies. And those >11.75-inch pipeline owner/operators should be required to have emergency response plans in anticipation of leaks/explosions. Gathering lines between 4-11 inches should also be regulated—perhaps with different approaches than the far more significant 11.76 and 16-inch pipelines. PHMSA's slide deck indicated that the recent build of >6-inch pipelines was 215 total (Class 1-4). PHMSA's slides state that only 183 Class 1-4 pipelines were installed totaling 1,942 miles of >6-inch diameter pipe. Further, PHMSA's analysis was that there were only 140 >12.75 ich pipeline installed between 2015-2019 during the boom period of shale gas. Surely the economic costs of new gathering lines will be lower for the indefinite future during the (unfortunate) period of gas glut. Commenter does not have the expertise on how to regulate the smaller pipelines or correctly define rupture for smaller pipelines as asked by PHMSA.

Conclusion

Commenter has provided significant improvements to PHMSA that should be considered for regulatory reform and in response to questions presented for comment at GPAC. Commenter does not oppose all aspects of the proposal for regulatory reform but believes that PHMSA has mistakenly failed to look at the many other safety benefits of pipeline regulation in its Cost Benefit Analysis. These examples from industrial and electric utility curtailments have been provided to PHMSA prior to this call for comments with economic data over the last year. Further, PHMSA should expand not shrink the reporting measures on its reporting forms. Nor should PHMSA raise the reportable threshold to $122,000 events. PHMSA should read the Carnegie Mellon study on non-reportable events under current threshold.

These recommendations are not made because the commenter opposes natural gas. It is quite the opposite. The commenter wants to make certain the public believes these pipelines are regulated and safe for electric utilities, industrial natural gas users and for homeowners who may unknowingly live near a variety of gathering pipelines.

Thank you for reviewing these comments. I am available to speak to any member of your staff. My direct telephone number is 703-507-6843.

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Fix the reporting of natural gas pipeline outages and pressure drops

by **Gerad Freeman, Jay Apt, Michael Dworkin**

Hundreds of times each year the natural gas pipeline system fails, shutting down electric power plants. Reporting of these failures is haphazard, and the United States must bring the gas pipeline reporting standards up to those used in the electric power industry if we are to make informed decisions about these interdependent critical infrastructures.

We are familiar with cascading *electric grid* outages such as the September 8, 2011 Southwest blackout that hit San Diego at rush hour, and the August 14, 2003 Northeast blackout. Less familiar are failures in the U.S. *natural gas pipeline system*. But they occur.

According to data from the North American Electric Reliability Corporation, fuel-starvation outages at gas power plants happened at an average rate of a thousand events per year between January 2012 and April 2016. Gas supply failures affected one in five natural gas plants in the USA during those four years.

Because data on the reliability of the natural gas pipeline system is almost impossible for anyone to find, our team spent a year meticulously combing through the reports filed by power plants – not pipelines – to count these outages. To our knowledge this is the first time anyone has done so.

Unlike electric power generator failures, gas pipeline outages are either not recorded or not available without a Freedom of Information Act request in most states. Being able to analyze and predict both system's reliability characteristics is essential to reducing the likelihood of huge monetary losses like the $3.6B in increased electricity costs experienced in New England during the Polar Vortex of 2014.

Roughly half of the electricity traded in New England's bulk power market is generated by natural gas power plants. Electricity prices on wholesale markets are set in a uniform price auction to supply enough power to meet expected demand. In such an auction prices are set by the highest bid submitted by the power plants needed to generate electricity for the grid during any given hour. In New England the market price is set by a natural gas power plant almost three quarters of the time. This provides a direct pass-through of natural gas costs into the bids in the power market. Usually that results in reasonably low prices. But when the gas system experiences an outage or a major pressure drop, scarcity can drive prices to extremely high levels.

Here's why. To avoid the added expense of reserving permanent space on the few pipelines that pump gas into New England from elsewhere, many power plant operators buy gas on the secondary spot market (sometimes called the capacity release market). The secondary gas market is set up so companies that own permanent space on pipelines can sell the portion of their reserved pipeline capacity that they do not need at unregulated prices. It is typically less expensive for power plants to buy gas from the secondary market than to buy permanent capacity on the pipeline itself.

But, when demand for gas spiked due to heating loads during the Polar Vortex, the supply of pipeline space available on the secondary market was not adequate to fulfill power plant demand and higher cost oil power plants were forced to pick up the slack. The consequences of these events were astronomical electricity price increases.

Only by combining accurate data from the gas system with existing data on power plant outages can we understand the situations where extreme temperatures cause demand for both gas and electricity to skyrocket, driving up prices on the spot markets and causing this sort of snowballing financial debacle.

An operational failure on a key pipeline serving an area like Algonquin in New England would similarly starve power plants of gas supply creating the same sort of financial meltdown. When these natural gas pipeline failures occur, there is no central source to which they are reported.

For power system reliability, it is important to know how often, where and why pipeline failures occur. This is because power plant operators are limited in the measures they can take to prepare themselves for gas interruptions. It is impractical to store backup gas supplies at the generator site because the required tank farm to store gas for just one day's power plant operation would occupy about a square mile, almost 6 times the land requirement for the natural gas power plant itself. Liquefied natural gas storage, even for a few hours' worth of plant operation, is very expensive. And underground storage at the plant is equally impractical for most plants. Another option to turn to is fuel-switching. But, only one quarter of gas power plants have the ability to switch to oil without halting operation and about half of those plants report restrictions to the duration of their oil operation because of on-site oil storage limitations.

The remaining three quarters of plants that do not have fuel-switching abilities are tied to the real-time reliability of the natural gas transportation network. When emergency situations arise on the natural gas grid, pipeline operators turn to a load-shedding protocol that outlines the order in which customers will have their gas supply turned off. The shedding of load restores operational stability to the gas grid in situations of high stress.

On the other side of the gas meter, however, as pipeline operators carry out their load-shedding procedure to restore stability to the gas grid and shut off fuel supplies to gas power plants, the burden of meeting demand for electricity is shifted to other power plants. If the generation shifting creates a large enough stress on the electricity network, other power plants sometimes fail, creating further instability on the electric grid.

Under current reporting requirements it is possible to get only an incomplete picture of the frequency of these kinds of interdependent natural gas/electricity infrastructure failures. One typical event affected pipeline operations in the Midwest in the second half of May 2017. During the event, caused by maintenance, a pipeline operator alerted its power plant customers that it reserved the ability to limit their hourly gas deliveries to one-sixteenth of their scheduled amounts. If this had occurred during high demand for electricity, or as an unanticipated outage, the consequences could have been a blackout.

Recent lessons in interdependency between the gas and electric grids (see box "Gas-electric interdependence") are a call to action to better align data availability of both grids' operational characteristics. We need commensurate reporting requirements for both systems. This is not a new message. In 2013, the North American Electric Reliability Corporation (NERC) released phase II of its special reliability assessment report entitled "Accommodating an Increased Dependence on Natural Gas for Electric Power." NERC identified a lack of "compiled statistical data on gas system outages that would be the equivalent to [the electricity plant Generating Availability Data System (GADS)] databases." NERC called upon the natural gas transmission sector to work with them on recommendations for data to be included in a central pipeline outage database with the purpose of conducting reliability analyses of the dual-grid system.

NERC's message has been heard in the academic community. Currently, academic teams across the country, ourselves included, are exploring the issues presented in the special reliability assessment. But nothing has been done in the ensuing four years to fix the data misalignment. We just don't know how vulnerable we are, and we don't know where to apply management attention to reduce the vulnerabilities.

Here, we explore the current federal reporting standards relevant to quantitative analysis of the reliability of the dual-grid system as they exist today and recommend a path of development for the central database recommended by NERC.

A Tale of Two Thresholds

For electric generators, the GADS Data Reporting Instructions outline specific, numerical thresholds for mandatory reporting. Events causing any power plant with nameplate capacity of 20 megawatts (MW) or greater (the vast majority of all plants) to fail at startup, to be completely unavailable unexpectedly, or to be unable to provide the full amount of power the plant promised to the grid must be reported. Power plant "derating" reports are mandatory for all events causing the equivalent of 2% or more of the power plant's "net maximum capacity (NMC)" to be unavailable for 30 minutes or more. A cause identification code is included with every power plant failure report. Between January 2012 and April 2016, over 1,000 failure events per year were reported by gas power plant operators claiming lack of fuel from the gas pipeline network. The data from these reports are confidential, but aggregate data that is fine for measuring reliability has been published.

Reliability events for gas pipelines, on the other hand, are reported to various entities, but with reporting thresholds that vary by jurisdiction. The Federal Energy Regulatory Commission (FERC) has jurisdiction over operation of interstate pipelines; PHMSA for interstate and intrastate pipeline safety; and the state Public Utility Commissions (PUCs) for intrastate pipeline networks – mostly for local distribution companies. According to high-level mapping data provided by the Energy Information Administration, roughly 60% of natural gas power plants with capacity of 20 MW or larger are within five miles of an interstate pipeline. The remaining 40% are likely fueled by smaller, intrastate pipeline systems. Therefore, it is important that reliability data are available for both interstate and intrastate pipelines. Because the natural gas grid in the U.S. does not have a central reliability organization like the electricity grid does, compiled data sources that are sufficient to model interdependencies between the two complete systems are hard to find.

One promising data source that could meet the needed criteria is outlined in 18 CFR § 284, Subpart I. The regulation states that FERC, through Form 588, requires "emergency transaction" reports from pipeline operators. An emergency transaction occurs as a result of "any situation in which an actual or expected shortage of gas supply would require an interstate pipeline company, intrastate pipeline, local distribution company, or [pipeline that is not under

FERC jurisdiction due to stipulations in the Natural Gas Act] to curtail deliveries of gas or provide less than the projected level of service to any customer." The reporting requirements of the regulation could be read to require transaction records for both complete gas curtailment events ("curtail deliveries of gas") and partial gas curtailment events ("provide less than the projected level of service to any customer").

But, this is only one way to read the rule. By our interpretation of the definition of an emergency transaction, the FERC-588 reports should capture the data that are needed to study reliability, but they don't. The filings under FERC-588 and other gas pipeline emergency reports are available on FERC's eLibrary website. Searching the eLibrary for emergency filings using the keywords "interrupt," "outage," or "curtail" produces 32 results from 17 unique pipeline events between 2012 and 2015. Most of the events were for gas flow diversions to avoid pipe segments taken out of service for maintenance. In these cases, the emergency transactions were brokered to avoid gas interruptions to customers.

Unfortunately, despite the fact that multiple delivery-failures have occurred, only one report over the period details a service interruption that could have affected a power plant located on the pipeline. Thus, the FERC-588 data are no help in understanding the reliability of the natural gas system.

In January 2016, a 30-inch steel transmission pipeline in the Southwest ignited due to a rupture of the pipe material. The explosion caused service to be interrupted on the pipeline for 35 days as repairs were made. While crews at a western gas distribution utility worked to fix a leaky valve in July 2016, they accidentally struck a 4-inch plastic main, causing the gas to ignite. Extensive system damage occurred, 30 people were evacuated and gas service was shut down for a day. In March 2011, a gas gathering line in the Gulf of Mexico was struck by a dredging operation and knocked out of service for over 250 days.

Not one of those events were reported to FERC.

As the FERC data are not very informative, the most comprehensive, easily-accessible, centralized source remaining that captures both inter- and intrastate pipeline data is the Pipeline and Hazardous Materials Safety Administration (PHMSA) Natural Gas Distribution, Transmission & Gathering Accident and Incident Database. The one service interruption in the FERC data is also captured by the PHMSA database. These data have been gathered since 1970 and are filed by the pipeline operator. The data are compiled and catalogued with a description of each pipeline incident and its subsequent root-cause investigation. PHMSA makes these data available publicly on their website. The thresholds that trigger a mandatory report to PHMSA are outlined in 49 CFR § 191.3. They include an event that results in both a release of gas or hazardous liquid from the pipeline and at least one of the following:

1. "A death, or personal injury necessitating in-patient hospitalization;
2. Estimated property damage of $50,000 or more . . . excluding the cost of gas lost or;
3. Unintentional estimated gas loss of three million cubic feet or more."

The legislative language also calls for any event that is "significant in the judgment of the operator, even though it did not meet the [previous] criteria . . . of this definition" to be reported. As PHMSA is a safety-centered organization, the thresholds focus on safety-related metrics; however, some of the fields on the forms that pipelines operators and investigators submit to PHMSA after an incident investigation capture important reliability metrics such as the system component affected, shutdown time, and the primary cause.

An analysis of the 673 PHMSA accident and incident reports for distribution, gathering and transmission pipelines between 2012 and 2015 shows that approximately 80% of reports met at least one of the automatic report conditions while 20% did not. The 131 reports that did not meet at least one threshold can be viewed as those "judged significant" by the pipeline operator. But, as mentioned in the Box "Gas-electric interdependence", the serious events at Aliso Canyon and in New Mexico are omitted from the data available on PHMSA's website. This leaves us to wonder how many other "significant" events are missing from these data, or even what a "significant" event is judged to be.

The only way we can effectively study interdependent reliability is if the standards for reporting pipeline outages and power plant failures are sufficiently equivalent. In comparing the GADS and PHMSA reporting thresholds, it is evident that the language for reporting outage events at power plants is far more stringent than for gas pipeline outages. Again, this is probably because PHMSA's mission is safety, but there is no central reliability organization for the gas network.

As a quantitative example of this misalignment, if we assume that a 460 MW combined-cycle natural gas power plant (the median size of such plants) was designed to continuously provide its net maximum capacity and it does so 60% of the time, a little better than the EIA's reported 2015 operational average, the plant would consume the equivalent of over 1.7 million cubic feet of natural gas per hour at 60°F and atmospheric pressure (gas flow at these conditions is referred to in units of "standard cubic feet per hour," or "scf/h") . That means that an unintentional release of 3 million cubic feet of gas to the atmosphere represents just under two hours of the power plant's full operation. Recall that for electricity-side reporting at this power plant, a complete power plant outage of any duration or a derating event equivalent to just 2% of the plant's capacity for 30 minutes or more must be reported; 2% of the power plant's capacity operating for 30 minutes would consume slightly fewer than 30,000 cubic feet of gas at 60°F and atmospheric pressure, a volume 100 times less than the PHMSA volumetric release threshold.

But power plants are fueled by high-pressure natural gas supplies. Volumetric flow rate and pressure of the gas moving within pipelines are tied together. If we further assume that the above power plant is made up of GE 7EA turbine units operating at an incoming gas pressure of 675 pounds per square inch (psi), in one hour, the plant would consume roughly 40,000 cubic feet of gas at pressure. And, a 2% derating for 30 minutes only represents roughly 600 cubic feet of gas consumption at pressure, 5,000 times less than the PHMSA threshold!

This simple example helps illustrate why we think *it is wrong that the only numerical, operational threshold for automatic gas pipeline incident reporting to the most comprehensive database is the volume of gas released.* Gas volume released, while important for financial, environmental, and safety reasons, is inadequate for system reliability analysis. Fluctuations in system pressure, or similarly volumetric flow rates, are the important system variables for gas system reliability as they characterize a pipeline company's ability to serve loads. Furthermore, as the language specifies, the explicit thresholds currently need be reported only if they occur simultaneously with an unintentional release of gas or hazardous liquid. Important reliability events without releases of gas from pipelines, such as reductions in operating pressure of the gas system, are left out of these explicit definitions. In the absence of more encompassing data, reliability analysts working with the PHMSA data are left to rely on the events that the operator judges to be "significant."

Perhaps more appropriate data are collected through other means and have been used internally for reliability assessments of the gas grid. We have not seen any hints or reasons to believe this is the case, but even if it is, an internal assessment isn't as good as having an open community reliability analysis. An open community reliability analysis would provide regulators and the many stakeholders of the gas grid with valuable information while also reducing the administrative burden of completing these analyses in-house. State agencies, academic institutions, trade organizations, businesses using gas for emergency backup generators, and large natural gas consumers – like power plants – should be provided access to pipeline reliability data that are not deemed a threat to national security. For power plants, these data are crucial for both siting of new power plants and existing capacity bid planning. Access to data that can capture events on both interstate and intrastate pipelines with the potential to affect the bulk power network should be provided outside the walls of government so experts across the country can analyze the reliability of the interdependent gas and electric grid systems on a level playing field.

First steps in the right direction

In September 2013, the National Association of Pipeline Safety Representatives (NAPSR), an organization with ties to the National Association of Regulatory Utility Commissioners (NARUC), released a document entitled "Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations." Within the report, NAPSR identified that state regulators had 308 enhanced reporting initiatives in place that would require pipeline operators to report safety conditions above and beyond those required by federal standards. They also identified that 33 states had various types of enhanced reporting standards with specific reference to the regulation underlying the PHMSA reporting thresholds. These enhanced standards included lowered property damage thresholds, outpatient injury reports, and other modifications to the CFR § 191.3 language.

One important set of initiatives identified by NAPSR are those that require pipeline operators to report outages affecting a specific number of customers, outages of a specific duration, or complaints of gas delivery pressure issues. At the time that the compendium was released, 20 states had one of these categorical reporting standards in place.

The problem is that each of these 20 states has its own reporting thresholds with varying stringency. For instance, Pennsylvania requires reports of all gas outages affecting the lesser of 2,500 customers and 5% of total system customers. Florida requires reports of outages affecting the lesser of 500 customers and 10% of total gas meters on the pipeline network. Washington requires reports of outages affecting more than 25 customers. Wyoming requires reports of all service interruptions of any size.

The state reports appear to be a step toward solving one piece of the reliability puzzle. But only three states, New Hampshire, Rhode Island, and Washington were listed by NAPSR as having a reporting requirement for system pressure issues. As discussed in the box "Partial gas failures are also a problem", system pressure fluctuations without a complete gas outage can shut down gas turbines. One proactive state, Maine, requires reports of all gas interruptions longer than a half hour that affect other utilities' critical facilities.

Data accessibility is also state-specific. Some states, such as Wyoming and Pennsylvania make the records they collected publicly available on their state information portal websites (if you know what search terms to use to find these data). In other states, the data from the records are referenced only as footnotes in annual pipeline safety reports or simply unavailable, requiring a Freedom of Information Act request to access the records.

A Path Forward

(see the Box "Recommendations")

To properly manage an increasingly interdependent gas and electricity system, the federal government should build on the states' efforts in updating the reporting thresholds for natural gas pipeline incidents to better align with the power plant outage standards and create a national standard. We recommend that pipeline incidents of sufficient size to trigger a mandatory power plant outage report should be reported. This additional threshold should be a specific requirement of pipeline systems with active firm supply contracts with power plants. This recommendation is based on the agreement between the pipeline and the power plant that a firm contract implies – there will be no unplanned curtailment of natural gas service unless necessary in an emergency.

Construction of any new standards should be based on the average amount of natural gas heat input required to produce a unit of electricity (the power plant heat rate) and modified to correspond to the most stringent power plant outage standards. The new standard should also be periodically revisited or updated to account for technological advances.

For pipelines with firm gas service contracts to serve power plants of over 20 MW nameplate capacity, events that reduce the pipeline's ability to serve the plant by their respective pressurized equivalent of 25,000 standard cubic feet per hour (scf/h) should be reported. Pipelines with firm service contracts in place to serve power plants with nameplate capacity of 20 MW or less should report events that reduce the pipeline's ability to serve the plant by 900 scf/h. These thresholds are based on the average heat rates of an advanced combined-cycle power plant and a baseload distributed generation plant, respectively. They are scaled to represent 2% of the median plant's net maximum capacity in each category, the power plant reporting threshold.

During the development and implementation of this new standard, stakeholders of both the electric and natural gas industries should be consulted. We recommend that representatives from the American Gas Association, Gas Technology Institute, National Association of Pipeline Safety Representatives (NAPSR), Pipeline and Hazardous Materials Safety Administration (PHMSA) and the North American Electric Reliability Corporation (NERC) should be consulted. During meetings with these groups, a key topic of discussion should be to better define what "an event that is significant in the judgment of the [gas system] operator" should include for natural gas pipeline incident reporting and to whom certain types of significant events should be reported. Additionally, care should be taken to identify the least amount of information required complete operational interdependency analyses. Pipeline operators closely guard their data for internal use. The new standard should be crafted in a manner that preserves proprietary trade secrets while also identifying the information that must be collected to conduct reliability analysis of the whole pipeline network.

We also recommend that the government use the New Mexico and Aliso Canyon events as the impetus to follow the electricity sector's example by designating a central entity to oversee the reliability of the natural gas delivery system (see the Box: Partial gas failures are also a problem). After the 2003 Northeast electric blackout, Congress mandated the establishment of a private, but federally chartered, electric reliability organization, with broad data collection and reliability enforcement powers. NERC won the competition. The PHMSA data discussed earlier comes from an organization with the mission of "protect[ing] people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives." Because safety is PHMSA's core mission, their data are unsuitable for conducting a thorough reliability analysis of the natural gas network. Instead, the effort to organize a central, NERC-like gas reliability organization could be spearheaded by a group with ties in both industry and government (for example, NAPSR). Congress should replicate what it did for electric power. The Electric Policy Act of 2005 (EPAct 2005) authorized FERC to appoint an Electric Reliability Organization (ERO) with authority to require mandatory reliabiilty and reporting standards for electricity utilities throughout the United States. In 2006 the FERC appointed NERC to that ERO role. Similarly, Congress and FERC could require the establishment of a national natural gas pipeline reliability organization.

Experts at NERC should provide guidance to the gas reliability organization. NERC's involvement in the early stages of this effort could provide not only important lessons learned during its own establishment, but the foundation for a collaborative relationship between NERC and its gas counterpart. In a country that produces the largest share of its electricity from natural gas, it is critical to coordinate reliability issues between the two grids.

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Recommended reading

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Box: Gas-electric interdependence

In February 2011, an extreme weather event hit the Southwestern United States chilling local temperatures to as low as 30 degrees below zero. The temperature dropped so low in places that water vapor at natural gas wellheads froze, restricting flow from production areas to the residents of the area. Simultaneously, regional power plants failed to keep up with electricity demand due to inadequate planning for the unexpected cold weather. The Electric Reliability Council of Texas (ERCOT) reported that over the first four days of February, 152 individual generator units at 60 power plants in Texas didn't provide the electricity they promised, triggering the initiation of rolling blackouts. More than 75% of the units reporting forced outages in Texas relied directly on natural gas as their primary fuel source. On the first night of the event, more than 8,000 MW of power generation unexpectedly dropped offline; that was 12% of the entire installed capacity of the ERCOT electricity grid.

Further compounding the problem, a segment of the regional pipeline system that shipped natural gas from the unfrozen production wells in Texas to markets in New Mexico and further West relied on Texas grid electricity to power its compressor stations. When the rolling blackouts started, the electric compressor stations shut down, and the gas pressure in the regional pipeline system fell starving customers in New Mexico of much-needed natural gas for heating. When all was said and done, 28,000 natural gas customers in New Mexico were forced to find other ways to protect themselves and their families from the bitter cold.

An internet search yields newspaper coverage and government hearing documents related to the February 2011 incident; but these events are absent from publicly-available incident databases. The gas service interruptions do not appear in the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Accident and Incident Database, the only readily-accessible central database of significant incidents on both inter- and intrastate pipelines available at the time.

Failures of electric generators or the grid are reported to state utility commissions, the federal government, and to the North American Electric Reliability Corporation. It is concerning that we know much less about outages in the growing natural gas infrastructure. In this regard, there should be a level regulatory playing field. But, there is not.

At the time of the New Mexico natural gas outage in 2011, the National Energy Technology Laboratory estimated that only 3% of natural gas transmission compressor stations nationwide were powered by electricity. The natural gas outage in New Mexico emphasized the gas grid's reliance on the steadfast operation of the electric compressor stations to provide critical heating fuel supplies. While the number of electric compressor stations without a second way to run the compressors has decreased because of the disaster, the gas network and electric grid remain dependent on each other. The fact that we have good data on failures in only one of these networks (electricity) puts us all at risk.

We should be concerned not only about pipeline outages, but also about the USA's huge seasonal natural gas storage facilities. The purpose of gas storage is to provide operational reliability during the months of high gas demand by pumping gas into storage during low-demand periods then pumping gas back into the pipeline network when needed. Special geological formations such as depleted gas fields, aquifer reservoirs, and salt caverns are used to store the seasonal natural gas.

When large storage facilities fail, they wreak havoc on fuel supply stability for power generators. In October 2015, a seven-inch injection well casing at the Aliso Canyon natural gas storage field in Southern California failed, creating the largest natural gas leak in United States history. Nearly four months passed as the operator and emergency responders worked to contain the leak. A joint task force consisting of representatives from the California Public Utilities Commission, Energy Commission, Independent System Operator, and the Los Angeles Department of Water and Power convened to discuss measures to prevent possible power outages in the summer caused by shortages of gas supplies for power plants. The result was the expedited approval of over 100 MW of battery storage projects including the 20 MW, 80 MWh Mira Loma project estimated to cost California ratepayers $20 to $40 million.

As with the New Mexico event, the Aliso Canyon event also received significant media coverage, but there is no database entry in PHMSA or anywhere else. PHMSA did not gain jurisdiction over gas storage facilities until almost a year later.

Box: Partial gas failures are also a problem

Complete natural gas outages are not as common as failures that drop the pressure in the pipeline. Power plant facilities are designed to receive natural gas from pipelines at a contracted pressure and volumetric flow rate based on available pipeline capacity and their generator equipment specifications. For example, two common natural gas turbines built by General Electric (GE), the 50-megawatt (MW) model LM6000 and the 85-megawatt 7EA, require incoming natural gas pressures of 290 and 675 pounds per square inch (psi), respectively. The Natural Gas Supply Administration reports that natural gas is typically transported in interstate pipelines at pressures between 200 psi and 1,500 psi. The lowest pressure interstate pipelines require power plant operators to maintain additional on-site compression equipment to run either model of the GE turbines. Pressure reductions on the lowest pressure interstate pipelines add stress to these on-site compressors. Even for the highest-pressure pipelines, a 55% drop in pressure would put a generating unit using the 7EA at risk of operational failure. An event causing an 80% reduction would put the LM6000 at risk of operational failure.

The problem is that it is hard to tell using public information when these pressure reduction events occur. The closest we can get from the pipeline side is through notices posted online by gas pipeline operators informing their customers a day or two ahead of time when they anticipate the need to impose physical constraints to protect the operation of their systems. These pipeline Operational Flow Orders (OFOs) can be issued because of an imbalance between scheduled or actual injections and consumption, pipeline or compressor failure, maintenance, weather, or any other unforeseen situation. Volumetric gas shortages and system pressure situations that do not necessarily create a complete outage can also trigger an OFO. Pipeline operators enforce OFOs by charging an additional fee for any volume of gas a customer moves on the pipeline in excess of the amount they scheduled the previous day. It is possible to search each pipeline's bulletin board website for OFOs as an estimate of how often situations that could create pressure reductions occur, but this is so time consuming that no comprehensive study has been done. Furthermore, the availability and frequency of these notices is pipeline-specific.

To get an idea of how often OFOs occur, we studied the pipeline with the largest number of natural gas power plants closely connected to it, Transcontinental. For this major pipeline, 21 OFOs were issued between August 2014 and April 2016. That's about once a month. We know that during at least 6 of these OFOs, an actual gas imbalance was present within a Transcontinental zone where gas power plants reported failures due to fuel starvation. 95% of the 290 power plant failure events were due to interruptible fuel supply contracts that allowed Transcontinental to turn off gas supply to those power plants first to stabilize the pipeline system. The remaining 5% of failures affected more than 900 MW of capacity at 4 power plants in the Northeast.

From the power plant side, the closest we can get to a ballpark estimate of the number of partial outages on the gas pipeline network is through reports of fuel-starvation power plant derating (partial outage) events. According to data from the North American Electric Reliability Corporation, nationwide, these fuel-related, partial outages at gas power plants happened at an average rate of 230 events per year between January 2012 and April 2016.

But, lax reporting requirements make it impossible to know the specific cause of these plant failures reported as lack of fuel. Did the plants fail to adequately schedule their gas supplies in the day-ahead gas market? Was there actually a physical pipeline failure? Or, something else entirely? The whole picture is murky, at best.

Box: Recommendations

State agencies, academic institutions, trade organizations, businesses using gas for emergency backup generators, and large natural gas consumers – like power plants – should be provided access to pipeline reliability data that are not deemed a threat to national security.

Pipeline incidents of sufficient size to trigger a mandatory power plant outage report should be reported. This additional threshold should be a specific requirement of pipeline systems with active firm supply contracts with power plants. The new standard should also be periodically revisited or updated to account for technological advances.

Congress should replicate what it did for electric power, and charter the establishment of a national natural gas pipeline reliability organization.