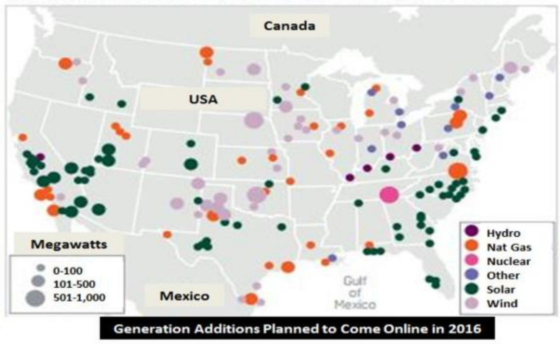
Push to Natural Gas Presents Advantages and Challenges to Electric Utilities Given Current Infrastructure's Readiness



SOURCE: EIA, PLATTS

EXECUTIVE SUMMARY Natural gas generation will continue to replace older coal plants and some coal plants that could not survive the Mercury Air Toxics (MATs) or Clean Power Plan (CPP) regulations. For many utilities, the CPP offered no alternative to retiring coal plants and switching to natural gas combined cycle (NGCC). It is too soon to know the final outcome of the CPP, whether the rule continues through the legal process or whether it will be withdrawn and replaced with a less stringent approach. The Obama Administration's rush to reduce CO_2 through a variety of regulations and policies overlooked significant natural gas infrastructure issues that are critical to electric utility reliability. Some of these infrastructure-related issues are the result of regulations issued by the Obama Administration as a coordinated and broader anti-fossil fuel (including natural gas) policy. Other regulations are safety related but the timing of them, even if needed, makes natural gas conversion in the next 2-3 years possibly more difficult. Utility executives had no way to predict that these anti-natural gas policies and regulations in natural gas segments would affect utility reliability. Collectively they could create short-term or *localized* reliability concerns for electric utilities relying mostly on natural gas. Regardless of the Trump Administration's possible decision about withdrawal of the Clean Power Plan[1] and replacement with a more conventional New Source Performance Standard (NSPS) regulatory system by U. S. EPA or states, natural gas generation is here to stay.

There are many positive reasons to generate electricity with natural gas. However, there are some operational issues and future challenges for natural gas generation because of local utility reliability. Causes include unexpected natural gas service downtime due to new pipeline safety maintenance or environmental regulations. Those pipeline and compressor station downtimes could likely be problematic in two waves—first from 2017-2022 and later from 2020-2025. EPA's new ozone/PM $^{2.5}$ regulations would likely result in nonattainment area pipeline compressor stations replacing gas motors with electric motors. While it is tempting to think of electric motors at gas compressor stations as new electric load this could be an additional problem for localized reliability for gas reliant utilities. A gas compressor station service disruption might pose problems many miles away from the electric utility if it is reliant upon only gas.

Emerging anti-natural gas sentiment across the country now includes concerns about health, noise, smell and declining real estate values. Not all opponents of natural gas infrastructure or NGCC generation fit a typical profile. Fears expressed against both the gas pipelines and electric utilities often result in a fossil fuel versus renewables debate. Although this paper primarily focuses on operational issues, it is important to note that FERC's cost recovery mechanism[2] for interstate pipeline companies allows for cost recovery for all new maintenance costs. These new maintenance costs were not expected when electric utilities negotiated natural gas contracts within the last two years.

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[1] West Virginia v. EPA case is technically pending a decision by the D.C. Circuit Court but also under a stay by the U.S. Supreme Court pending their review in a future hearing. President-elect Trump's public statements strongly suggest that the CPP will be withdrawn, although it is not clear at the time of this analysis what that withdrawal process will mean in terms of subsequent proposal by U.S. EPA or deference to states to regulate existing electric utility sources.

[2] Columbia Pipeline Decision, 2015. For details see https://www.ferc.gov/whats-new/comm-meet/2015/041615/G-1.pdf and https://www.ferc.gov/whats-new/comm-meet/2015/071615/G-6.pdf

Intrastate pipelines can seek rate cases typically every three years before state public utility commissions. Those cost recovery cases can reflect many environmental and safety related costs.

Most significant for gas-generating utilities, natural gas pipeline's compressor station repair downtime ranges from one week to a month. Utilities need to know if those methane leak repairs might cause gas delivery delays and might cause some localized utility reliability problems. Unfortunately, EPA's new methane leak repair regulation on new compressor stations and pipelines[3] do not allow for delays of repairs during low electric demand or pipeline shoulder season. In some cases, utilities may want to contemplate obtaining special air permit dual fuel use when natural gas is not available for a day, week or month. Use of oil generation is allowed during weather-related natural gas curtailment events (flooded pipelines, hurricanes and tropical storms) but air permits might allow 10 percent of the entire year's hours and only if a governor declared an emergency. Further, electric utilities need to know if they can run the dual fuel (presumably oil) during ozone seasons[4]. These maintenance-related gas curtailments might affect more than one power plant if only one pipeline serves more than one power plant.

Additionally, utilities may want to contemplate mutual aid relationships or ownership of gas storage for reliability purposes since natural gas storage may be under new safety regulations[5] resulting from the 2015 Aliso Canyon leak in Southern California. North American Electric Reliability Corporation's (NERC) December 2016 Reliability Assessment Report[6] pointed out some constraints on infrastructure. While NERC noted that natural gas is abundant and available in many parts of the U. S., it noted that there are infrastructure permitting delays in *some* regions that give them concern—in particular New England. NERC's Assessment did not mention the possible localized reliability issues that electric utilities could face resulting from new safety and methane repair regulations on the midstream pipeline segment or that gas storage locations could be under significant repairs and system upgrades under PHMSA regulations. NERC has a separate report expected in May 2017 to address natural gas infrastructure issues for the power sector.

This paper's references to PHMSA safety requirements presume they are needed and offers no criticism of PHMSA's interim final rule or anticipated 2017 "mega rule" for natural gas pipelines.

Nationally, electric utilities are moving from coal to natural gas for a variety of reasons—including market forces, retiring plants and environmental regulations. Baseload natural gas generation is a viable option that was almost unthinkable in most states only a decade ago before shale gas became technically and economically feasible. However, current national shale gas supply doesn't necessarily mean the natural gas is positioned for electric utilities to meet daily winter peak or new summer peak demand. Few utility managers and fuel purchasers could have anticipated new infrastructure repair costs when "penciling out" electricity rates. Nor would utility managers know that firm gas contracts might not mean uninterruptable during a natural gas maintenance-related force majeure event. U. S. EPA treated these two industries as entirely disconnected when regulating CO_2 for power plants and methane for midstream pipelines when the two industries will be inextricably linked. *The NSPS 111(d) comments are replete with information on natural gas infrastructure issues which EPA ignored[7].*

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[3] Known as OOOOa or "quad O-a" referring to its section of the Clean Air Act for New Source Performance Standard which was published June 12, 2016 and effective for new pipelines/compressor stations built after Sept. 18, 2015. In some instances, the leak repair can trigger older existing pipeline compressor station repairs or reach into existing pipelines.

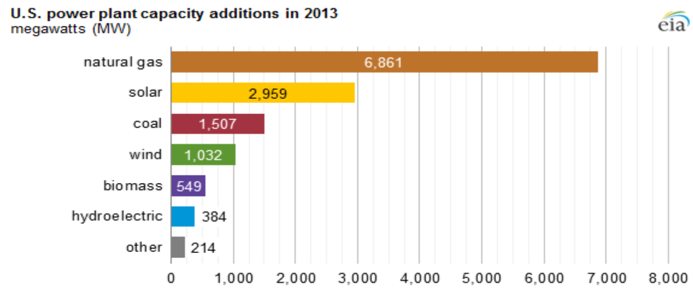
[4] Typically, May-September in "nonattainment" or noncompliance locations under the Clean Air Act for smog pollution

[5] PHMSA's Interim Final Rule on Natural Gas Storage, issued Dec. 14, 2016 and effective sixty days from publication in Federal Register is the first of several new safety rules under Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016. http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Underground_Natural_Gas_Storage_Interim_Final_Rule_Corrected.pdf

[6] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

[7] Comments submitted by American Public Power Association, Utility Air Regulatory Group, National Rural Electric Cooperatives Association, etc., Dec. 4, 2015 and during many briefings from 2010-2015.

PUBLIC OPPOSITION TO "FRACKED" GAS AND PIPELINES



Just as anti-coal activists used a variety of regulations and litigation measures to thwart coal similar opposition is underway now against natural gas and its infrastructure. Environmental organizations have taken their national "keep it in the ground" campaigns before state PUCs and city councils. Nationally, they oppose new natural gas pipelines and compressor stations before FERC where their complaints include claims about public health, noise from compressor station methane evacuation or "blowdown" events, and loss in residential property values.[8] Not all gas opponents are the same. In some communities, the opposition is due to a misunderstanding that solar and wind are equally viable and affordable. In other circumstances opposition is due to noise, smell and fears about property values. In some communities, public opposition includes massive demonstrations and citizen activists' surveillance of the homes of PUC or utility officials on a 24-hour basis. While the most extreme anti-oil pipeline demonstrations have occurred in North Dakota, Nebraska, and New England[9] there is no reason to expect different reactions to natural gas pipelines elsewhere. Opposition to the Constitution Pipeline and several New England natural gas pipeline projects resulted in withdrawals or cancellations in 2016. These failed projects demonstrated a lack of community support for natural gas at a time of very high electric costs for consumers.

Some anti-gas and anti-oil pipeline groups are using crowdsourcing[10] for financing opposition (e.g. public demonstrations and litigation).[11] While the financial contributions may be quite small, the opposition groups appear in locations as varied as Idaho, Florida, Texas, Ohio, Colorado, Utah, and Tennessee. Opponents use crowdsourcing and social media to rally thousands of followers—some of whom are very vocal and can be mobilized quickly for public demonstrations. While crowdsourcing has not yet been used against natural gas power plants, the Community Environmental Defense Council (CEDC),[12] an anti-fracking group, has emerged in many locations with new natural gas pipelines. CEDC is aligned with an academic group of >500 scientists[13] organized against the oil industry often using public meetings space for educational events. Some local governments have accepted their meeting requests believing they were affiliated with local universities only to discover later they are anti-oil meetings.

Electric utilities should expect the anti-fracking view to extend to permitting of NGCC units and pipeline extensions or new pipeline/compressor stations with complaints against "fracked gas". Additionally, some academics, pediatricians and pediatric nurses have become active around fracking or fracked gas distributed by pipelines because of concerns with air pollution, alleged exposure to benzene, and allegations of premature births.[14] Immediately following the election of Donald Trump and his statements about withdrawal of the CPP and support for coal, Sierra Club, NRDC and many other NGOs announced moving their anti-fossil fuel campaigns to states and local governments.

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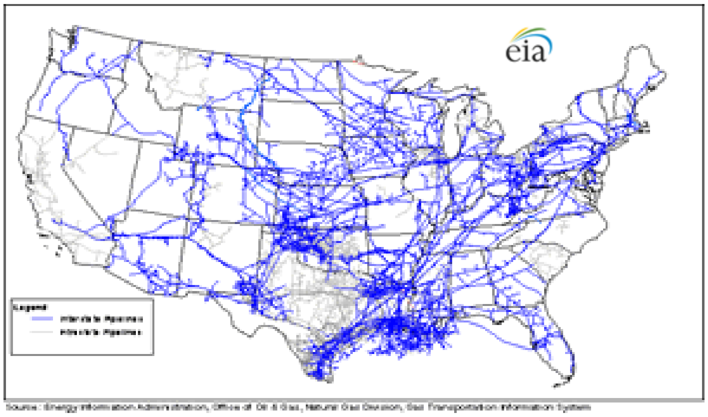
[8] Public opposition at FERC ranges from exposure to benzene as a carcinogen, headaches, increased premature births, and lowered home values due to proximity to pipelines and compressor stations.
[9] Opposition to Constitution Pipeline and several New England natural gas pipeline projects resulted in withdrawals or cancellations.
[10] See www.gofundme.com
[11] https://www.gofundme.com/2xfiz0?ssid=856080072&pos=2
[12] http://www.cedclaw.org/
[13] Scholars Strategy Network See www.scholarsstrategynetwork.org
[14] http://wspehsu.ucsf.edu/wp-content/uploads/2015/10/hydraulic_fracturing_2011_parents_comm.pdf and http://www.pehsu.net/

WHY PIPELINE AND COMPRESSOR STATION DOWNTIME DURING REPAIRS MATTERS TO UTILITIES Natural gas is methane, and methane is a greenhouse gas. While opinions about methane's GHG intensity vary between 25 times more powerful than CO_2 to 85 times more powerful, its role as a GHG is not in doubt. As a part of the Obama Administration's Climate Action Plan, EPA finalized its methane (NSPS) regulations for the oil and gas sector. The rule includes new requirements to test for methane leaks at new pipelines and new compressor stations with cameras. This action was EPA's version of NSPS for the upstream oil and gas sector, including the pipeline industry. The rule cannot be withdrawn by a Congressional vote of disapproval under the Congressional Review Act (CRA) according to the House Parliamentarian because it was published on June 3, 2016[15] before the Congressional Review Act's limited "look back" eligibility date. U. S. EPA could issue a revision to the rule addressing the frequency of repair and timing or discretionary enforcement for repairs made after 30 days. But, until that happens, the power sector should plan on the rule as published. The rule applies to any pipelines under NAIC's code 486210 that commenced after September 18, 2015, although the rule's effective date is August 2, 2016.[16]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

U. S. Natural Gas Pipelines

The most significant regulatory requirements require pipeline owner/operators to test for leaks and repair those leaks within 30 days. The leaks are detected through use of Optical Gas Imaging (OGI) cameras and can find very small compressor station leaks. There is no threshold to ignore tiny leaks.

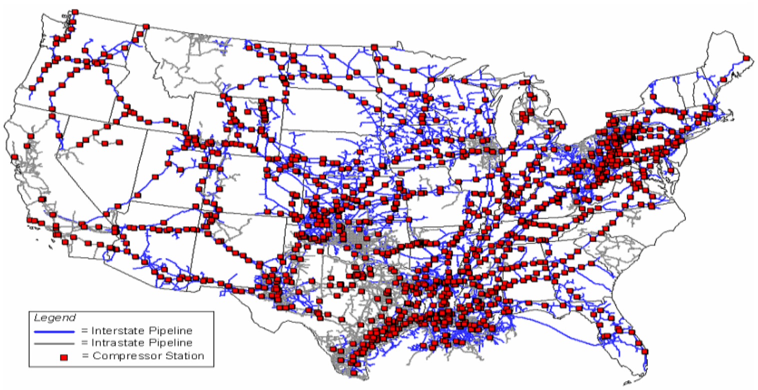
Compressor stations are essential to moving natural gas from upstream production to processing facilities, electric generators, and industrial facilities. Typically, they are located every 80 miles as directed by Right of Way and proximity to their customers—whether existing gas production, gathering lines, or industrial facilities. Their locations are also dictated by a number of spark suppression and other safety issues and are designed to avoid sharp curves or twists in pipelines that impede corrosion detection through "pigging" devices. While some compressor stations and pipelines have secondary routing, most do not. Those with secondary routing avoid system downtime. Pipelines and compressor stations with secondary routing are often difficult to permit or get through PUCs or FERC because they are more expensive.

The map above shows that some states have an abundance of natural gas pipeline for existing or new customers that other states have very little pipeline. Further, what is not clear from maps like this is the direction of flow and whether the pipeline has additional capacity for electric utility customers. And the map does not differentiate where pipelines are built for the upstream production and gathering facilities. Not all of the new pipelines were built for utilities.

[15] Often referred to as "OOOOa" or "quad a" as it pertains to the section of the Clean Air Act. See Federal Register notice https://www.federalregister.gov/documents/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources or https://www.gpo.gov/fdsys/pkg/CFR-2016-title40-vol8/xml/CFR-2016-title40-vol8-part60.xml

[16] Commencement dates under NSPS are based upon proposed date not final agency action—this is unique to this one part of the Clean Air Act. Normally the effective date would be 60 days after publication of a new rule. In this case, this means any compressor station or pipeline commenced after September 18, 2015—before the rule was finalized.

U.S. COMPRESSOR STATIONS



THIS MAP DOES NOT REFLECT MANY DOZENS OF NEW COMPRESSOR STATIONS BUILT IN THE LAST FOUR YEARS, BUT MOST OF THOSE WERE FOR UPSTREAM GAS PRODUCTION GATHERING LINES AND NOT FOR POWER PLANTS. SOURCE: SOUTHWEST RESEARCH INSTITUTE, 2012 PRESENTATION

Power generators should give careful consideration to possible secondary routing of gas for both obtaining product (just as they often had secondary rail or barge delivery options for coal) and avoiding unscheduled downtime. Secondary routing is expensive but might not be needed everywhere.

Pipeline operators periodically must evacuate or "blowdown" methane within the pipeline for safety reasons, and these blowdowns cannot be scheduled or predicted. Further, electric utilities should anticipate public inquiries and complaints about sound from these blowdown events if the new compressor stations are located near residential areas.[17] Although the decibel level for routine compressor station operation is regulated by FERC, assertions that the safety related evacuation or blowdown events sound like trains or airplanes landing is within reason. For some citizens, noise is the primary opposition to permitting for new compressor stations rather than philosophical distaste for fossil fuels. It can be very useful to address noise and smell issues early with the public. It is also important that the public understand the distinction between normal running noise and evacuation or blowdown events that can happen at unplanned times. While these issues typically emerge at public hearings or permitting of pipelines, utilities should expect the permitting process for NGCCs to bring up these issues outside the fenceline of the power plants. Similar anti-coal issues outside the power plant's footprint emerged during coal plant hearings over the last decade.

Each gas compressor has approximately 1,500 valves, flanges, and hatches that can, at one time or another, leak**.** Age does not always indicate propensity to leak, and new pipeline compressor stations can leak just as easily as a forty-year-old compressor. Many pipeline companies do not have those replacement valves, flanges, and hatches on site and ready for use, they will need to conduct audits to ensure part replacement and compliance with the EPA NSPS rule. While this might be corrected within a year or so, utilities should inquire as to the readiness of valve repairs, trained contractors or pipeline staff to make repairs within 30 days, and whether that pipeline needs any replacement parts needing metal fabrication. These questions would not be normal questions asked of coal delivery providers because of coal supplies on the ground. Many rating agencies[18] rated utilities based upon maintaining an average 29 days of coal on site and thus fuel supplies were often kept on site. (It is not clear if rating agencies will look at gas supply issues in a similar way when scoring projects).

Most pipelines do not leak—but if they do, those leaks are often detected through a variety of safety tests and repaired under regulations by the Dept. of Transportation's Pipeline and Hazardous Management Service—often simply referred to as PHMSA (pronounced "FEM-SA"). Many pipelines are also regulated under state safety laws and regulations. The use of leak detection and repair devices (LDAR) is critical to finding leaks in the compressor station's many thousands of parts. Methane leak repairs require the compressor station to be taken offline-often for approximately one week. Some individual compressor station leaks take as long as a month. In rare instances, compressor station leaks can take

[17] Watch and listen to a YouTube video of blowdown events at https://www.youtube.com/watch?v=WtSH5V1YQvQ; This video shows a decibel reading range of 48-86 decibels from the deck of a nearby home. While this particular reading exceeds FERC decibel limits, it is used in many public hearings and in social media by opponents of compressor stations. Most compressor stations operate well below this high decibel reading.

[18] Fitch, Moody's and Standard and Poor's

up to one year to repair[19]. Utilities may want to ask if parts needing metal fabrication are on any pipeline serving that utility before deciding to close or decommission coal plants. Blowdowns can require evacuation of a pipeline for five miles in all directions associated with that compressor station. This means taking the station offline unless there is a secondary pipeline routing. Again, this means utilities must understand their pipeline providers in ways not needed for rail or barge delivery of coal since a three-month supply coal could sit on the utility site minimizing risks of coal mine force majeure or rail delivery problems.

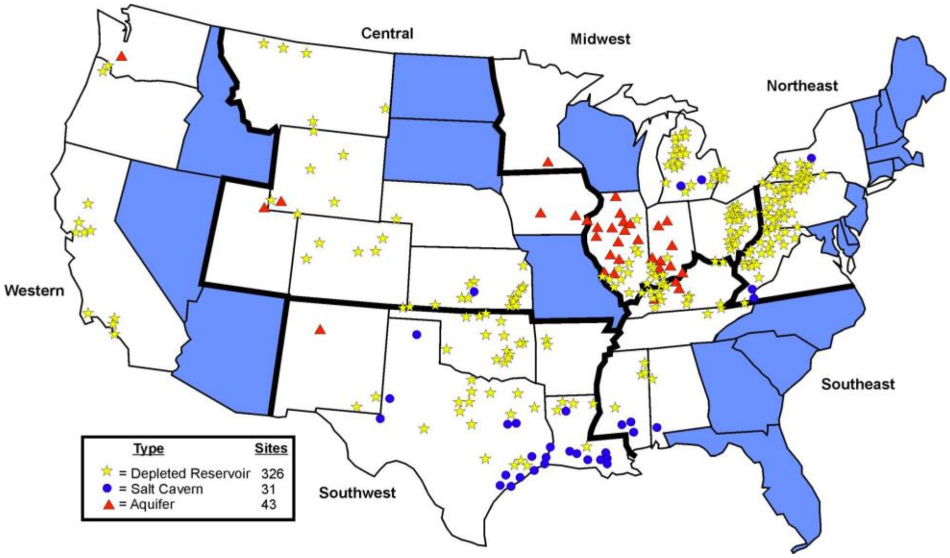
For some newer pipelines and compressor stations there may be secondary re-routing options that avoid this—but most compressor stations do not have those options. Unfortunately, EPA's rulemaking does not allow pipeline companies to delay leak repairs during pipeline's next scheduled outages or during shoulder season. EPA's rationale was that methane is so CO_2^E intensive that leaks must be addressed within 30 days in order to compensate for the climate change impacts. The leak repairs are triggered regardless of how tiny the wisps that are identified by cameras. The oil and gas industry has initiated litigation under this rulemaking, and it is possible that a settlement under Trump Administration could result in a more reasonable response time for repairing leaks. Avoiding the risks of force majeure because a pipeline and its new compressor stations must be taken offline should be appealing to the new Trump Administration. EPA's NSPS rule only covers new pipelines and compressor stations, but given how many new buildouts have begun since September 18, 2015, this repair/replacement time and frequency is significant. And the "new" distinction is not as clear cut on pipelines as they are on factories or power plants. Occasionally a new pipeline leak repair can "reach into" an older pipeline or compressor station based upon the pipeline's configuration.

The 2012 compressor station map above (see page 5) indicates their location and type - intrastate and interstate. Even if the compressor station "upstream" of a power plant is functioning, downtime elsewhere might affect gas distribution to power plants in that region. Utilities may want to discuss arrangements with the natural gas provider to purchase gas from another nearby source in the event of unplanned downtimes at nearby pipelines. These arrangements are more critical for power plants with variability in load than for industrial users with predictable gas demand. Pipelines cannot line pack adequately to serve a >300 mw power plant for a day. Firm or uninterruptible contracts do not preclude service disruptions if the compressor station and pipeline are out of service to meet EPA or PHMSA regulations

WHAT CAN UTILITIES DO TO PREVENT SERVICE DISRUPTIONS? Long-term contracts have many merits but cannot prevent all possible curtailments if the natural gas delivery system is taken offline for safety reasons or EPA regulatory maintenance. Also, there could be instances where the pipeline is functioning well but the storage location is out of service. Secondary routing is optimal for reliability but usually increases costs. Some utilities may want to have real-time communications with the pipeline within a day of the leak being detected to ensure that there are plans to work around the service disruption during repairs. Utilities might want to obtain special state air authority permit variances to run without limitations during pipeline or compressor station downtime. Some state agencies may be leery because the burning of oil during summer ozone seasons could temporarily increase SO_2 and NOx significantly. Further, municipal power utilities that co-manage water utilities or telecom may want other "belts and suspenders" in dual fuel permitting to ensure no service disruptions to other essential water or communications services to community customers.

[19] Comments on proposed rule from Interstate Natural Gas Association of America to EPA, December 4, 2014

NATURAL GAS STORAGE IS ESSENTIAL AND NOT ALL STATES OFFER SUBSURFACE STORAGE OPTION



Natural gas storage is essential to all electric utilities that opt to primarily burn natural gas. For utilities in New England, Florida, and some parts of the Midwest, natural gas storage is challenging because the states have unsuitable geology for subsurface storage. Natural gas moves at approximately 25-35 mph and line packing is not possible for power plants to address fast changing demand. The higher the ramp rate the more critical storage is for utilities. Utilities located in states like Texas with existing pipeline infrastructure or existing natural gas storage may find there are no gas storage (or pipeline) concerns. However, many states have no existing subsurface gas storage. Or they have no *rapid turn* storage locations appropriate for power plant customers. The details about natural gas storage for the power sector are well explained in APPA's 2010 study[20]. Arizona recently rejected a gas storage project due to concerns about water storage needs.

Storage contracts or leasing physical space at new in-state above ground storage locations might be an option for some utilities in states with no subsurface options. Some electric utilities might want to consider hosting a jointly-owned natural gas storage location at a decommissioned coal plant or brown field location. Perhaps former U.S. Navy facilities with deep-water ports might be possible for above ground or LNG terminals in states where no other storage exists. The gas storage issue merits further study where regions with no subsurface gas storage options move from coal to natural gas. States with long pipeline permitting processes due to other factors including other laws, regulations, high Renewable Portfolio Standard requirements may find such a government agency study useful. States in the Northeast which have both long permitting processes for pipelines and compressor stations and unsuitable geology for natural gas subsurface storage. All solid blue states in the map above may also prove to be problematic. States like Florida have a propensity to deal with power outages due to tropical storms or hurricanes and have fewer natural gas pipelines and no subsurface natural gas storage. Hurricane season also runs concurrent with ozone season and peak summer demand. While some Florida utilities may want to fuel switch to natural gas there are some unique circumstances in Florida worthy of consideration. Perhaps dual fuel (oil) could be allowed for longer use than 10 percent of the year in states with gas storage limitations. This would require significant Clean Air Act permit approvals by U. S. EPA and states.

In October 2015, Sempra Energy's local natural gas storage location serving southern California had a serious storage leak for almost three months. The full investigation is still underway as to the causes of that leak, why it was not detected by any internal pressure loss devices, and why the emergency shut off valve was removed and not replaced. That leak caused many Federal and state regulatory authorities to inquire if that leak was a "one off" event or perhaps an indicator of larger natural gas storage infrastructure problems. The leak was repaired in February 2016 but, after almost 13 months, the Aliso Canyon gas storage facility is still not fully operational. In fact, only about 32 of the system's 114 storage locations have passed the safety tests being conducted by the California Division of Oil, Gas and Geothermal Resources (DOGGR). In order to avoid risks of blackouts and brownouts, Los Angeles Department of Water and Power (LADWP) was allowed to burn oil throughout summer, 2016. That fuel oil along with extensive Demand Side

[20] http://www.publicpower.org/Media/weekly/ArticleDetail.cfm?ItemNumber=28462

Management programs got Southern California through the summer months with no curtailments. In December, 2016, California state authorities sent out emergency requests for business and residential users to adjust their thermostats to 68 degrees and not run any non-essential electrical devices to avoid gas curtailments and blackouts. While it was cold for California, that evening was 42 degrees.[21] It shows how vulnerable the electric system is if gas storage is not fully operational. It appears that it may take as long as six months before all of the natural gas storage locations in California are in full operation—just in time for summer peak.

As a follow-up to the Aliso Canyon leak, the U.S. Department of Energy's Interagency Task Force on Natural Gas Storage Safety issued a report in October, 2016.[22] This report (in conjunction with PHMSA) indicated that 80 percent of the natural gas storage infrastructure in the U.S. is antiquated, built during the 1970s or before. The report suggested that DOE is concerned that Aliso Canyon might not be a one-time event. The DOE report includes 44 policy and regulatory recommendations to ensure safety and reliability of the natural gas storage system.[23] The most important are:

- New wells should be designed so that a single point of failure cannot lead to leakage and uncontrolled flow, and except under limited circumstances, natural gas storage operators should phase out single point-of-failure wells;
- Operators should adopt risk management plans that include a rigorous monitoring program, well integrity evaluation, leakage surveys, mechanical integrity tests, and conservative assessment intervals;
- DOE and DOT should conduct a specific and thorough joint study of subsurface safety valves;
- Adoption of API RP 1170 standard, "Design and Operation of Solution-Mined Salt Caverns Used for Natural Gas Storage," First Edition, July 2015; and
- Adoption of API RP 1171 standard, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, First Edition, September 2015.

In the introduction to the report, Secretary Moniz wrote "Power system planners and operators need to better understand the risks that potential gas storage disruptions create for the electric system". The report further recommended that power plants use "dual fuel" to avoid service disruptions (although it did not express for how long that fuel should be burned and what type of fuel). Nor did the DOE report acknowledge that dual fuel is limited to very few hours of the year under the Clean Air Act. Also, very few power plants were designed to run on dual fuel. However, perhaps the DOE's report points to a possible policy solution possible under the Trump Administration. Dual fuel could help avoid service disruptions and power outages.

On December 21, 2016, PHMSA issued an interim final rule that incorporates several of the recommendations in the DOE report.[24] While the rule was embraced by the two-major oil and gas trade associations on substance,[25] the organizations said in a statement that the new safety requirements could not be met by the nation's >400 natural gas storage facilities in the one year required and that similar past regulatory actions gave the industry as long as ten years for compliance. This statement implies that for the natural gas storage segment to fully implement the new safety standards they need between one and ten years to comply which certainly begs the question about electric power sector reliability. No one has yet predicted required downtime for implementing these natural gas storage safety requirements.

Utilities should be aware of this DOE report and should inquire of their natural gas providers about the status of the safety repairs at natural gas storage locations that will serve their electric utility. Discussions about service disruptions

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[21] www.weather.com
[22] https://energy.gov/articles/federal-task-force-issues-recommendations-increase-safety-and-reliability-us-natural-gas
[23] https://energy.gov/fact-sheet-ensuring-safe-and-reliable-underground-natural-gas-storage
[24]https://energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf
[25] American Petroleum Institute (API) and Interstate Natural Gas Association of America (INGAA)'s press statements, Natural Gas Intelligence, December 15, 2016, www.naturalgasintel.com

and time needed to make safety changes to the storage location should address all electric utility reliability concerns. For more details on the storage safety standards see the *National Law Review* article by Van Ness Feldman.[26]

For those utilities that plan to convert from coal to gas, it might be prudent to determine if the natural gas storage facility can meet all new regulatory requirements as well as to contemplate the additional regulations anticipated by the PIPES Act passed by Congress in summer, 2016 before a coal plant is retired and decommissioned.

ANTICIPATING EPA'S REGULATORY REQUIREMENTS ON GAS COMPRESSORS UNDER 70 PPM OZONE REGULATIONS: The gas pipeline industry expects that their gas compressor motors will be required to be replaced with electric motors. The precise date is not known because of the implementation process of new 70 ppm standards. For the power sector, the additional load from the local compressor station could be a positive or a negative. Additional load is usually appealing. However, the costs to replace these gas motors is quite high, and industrial customers may oppose paying for them since the electric utility benefits financially. Some utilities may not have transmission and distribution systems designed to serve a natural gas compressor station. Utilities must weigh many factors including voltage support before taking on additional compressor station load. To add to the complexity, some electric utilities may not want the natural gas compressor stations to have electric motors due to possible down time if there is electric power disruption.

Further, EPA's use of AERMOD dispersion modeling and other air modeling may make it more difficult to scrape a coal plant and replace it with NGCC if the area is in nonattainment with the tightened air standard. For some utilities, an offset might be required. AERMOD may also limit compressor station permitting because of the compressor station's lower vents. (While AERMOD and other EPA modeling is not a focus of this paper, there is no question that getting any source of NOx, SO_2, and NO_2 permitted is tough. Correcting AERMOD's overly conservative design would help many industries get permits).

NOISE AND SMELL If a compressor station must be added close to residential or historical locations, the pipeline company, electric utility, and community may have to develop satisfactory ways to address noise—both routine compressor station running noise and blowdown (evacuation) noise when the pipeline and compressor station must evacuate the methane for safety purposes. If the natural gas provided to the utility comes from states[27] that require mercaptan or other odorants to be added at the upstream source, local communities may need specialized public communications to explain why the odorant is used. Some communities prefer the use of an odorant because it informs the public that there is a leak. Other citizens oppose odorants because they fear that, following the Aliso Canyon leak, that the odorant causes headaches, nosebleeds, etc. Some pipeline companies are exploring alternatives to mercaptan. While most citizens would not smell mercaptan during routine operations, those living near compressor stations might smell the mercaptan more frequently during blowdown and repair events. With good community outreach these local residents can become accustomed to the smell (and noise) issues in the same way that coal plants or water treatment plants and substations were accepted. Ironically, if the EPA methane NSPS regulation or pipeline/compressor station continues to require methane leak repairs within 30 days of leak detection, the compressor station methane blowdown (evacuation) smell could be more frequent, resulting in more methane emissions- and perhaps more ambient odor.

Some industrial gas customers oppose mercaptan in their gas supplies when making products with natural gas. Before utilities decide whether to request mercaptan (or add odorant at city gate), consultation with key industrial accounts might be prudent.

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[26] http://www.natlawreview.com/article/phmsa-issues-interim-final-rule-addressing-safety-underground-natural-gas-storage

[27] Currently Pennsylvania requires mercaptan to be injected at the production site rather than at the city gate because of concerns about safety.

FORMALDEHYDE MACT Although EPA has not proposed a formaldehyde MACT standard for NGCC gas turbines, this should be anticipated when designing new NGCC units. It appears that the likely control measure, based upon current state of the art controls, involves retrofitting with a steel catalyst. Planning space for steel catalysts is not difficult.

PUBLIC MONITORING-COMING TO A COMMUNITY NEAR YOU Miniaturized and portable monitoring devices have been encouraged by U.S. EPA, some state agencies, university researchers, vendors, and citizen activists. Recently the Illinois EPA purchased 400 monitors to detect precursors to ozone. It is very likely that similar monitors and wearable devices will be used as ways to detect methane in and around power plants, compressor stations, and distribution pipelines. Electric utilities should become aware of these miniaturized devices and their imperfections. Some devices detect with sophisticated accuracy while others require calibration that the average user cannot manage. This can lead to false readings and public health scares. It might also lead to toxic tort litigation on a variety of pollutants. Community activists are expected to form data networking to monitor all pollutants coming from power plants and delivery infrastructure. U. S. EPA and state agencies should undertake effective communications to explain these devices and use them in productive ways without false positive readings. It is fruitless for power sector to oppose these as they will be used by activists and neighbors. It is wiser to find ways to use them productively. Similarly, electric utilities should not be surprised if some activists demand Optical Gas Imaging (OGI) cameras to detect methane and other pollutants. at power plants.

Google and Environmental Defense Fund (EDF) have also used cars with methane monitoring devices across almost a dozen U.S. cities to detect leaking compressor stations at Local Distribution gas utilities.[28] This project will likely expand to more cities in 2017 in anticipation of any EPA regulations on existing pipeline/compressor station sources. The law is clear about requiring NSPS on new pollutants. Unless Congress amends the Clean Air Act, NSPS regulations on existing sources should be expected—even if far less stringent than the EPA NSPS ("OOOOa") regulation on new sources. One might presume that the NSPS for existing sources would be managed by states[29] giving local NGOs more opportunities to attempt addressing methane on each permit. EDF has said it will use studies and data in state permitting procedures under 111(d) regulations whether the regulation is a U. S. EPA responsibility or that of the states.

ANTICIPATING THE PUBLIC'S PRESSURE FOR SOLAR OR WIND IN LIEU OF NATURAL GAS Solar power technology and costs have made it far more economical in the last three years. While solar generation may not be optimal in many Midwest or coastal SE locations due to cloud cover, moisture droplets, or tree canopy, the Nongovernmental Organization (NGO) community will continue to prefer renewables over natural gas. Wind, while extremely reliable in states such as Texas, Iowa, Illinois, Kansas, Oregon, Colorado, North Dakota, and Wyoming, other states such as Florida have virtually no wind adequate for power generation.

The extensive pro-renewables campaign includes standard environmental opposition, crowd sourcing by neighborhood associations, and general opposition to natural gas infrastructure approvals at the PUCs and FERC. The local opposition to natural gas can reflect a variety of views ranging from reduced property value to human health risks. Even some people not normally active in anti-fossil fuel advocacy efforts appear to be joining anti-gas efforts in unlikely locations including Ohio, Wyoming, Colorado, and Texas. Some of the opposition to natural gas is merely because of the misunderstanding that solar (or wind) cannot yet be for reliable baseload generation without battery technology. Improved renewable prices may make some natural gas generation appear less optimal to citizens, consumers, city councils, or those who do not understand peaking. Nor will all customers understand that, for now, the more cost-effective solar is utility-scale solar not residential rooftop solar. Utilities might anticipate such assertions about both

[28] https://www.edf.org/climate/methanemaps

[29] Consistent with 111(d) NSPS has conventionally been administered for non GHG pollutants—on specific source and contemplating the remaining useful life etc.

the levelized cost of electricity and the human health costs associated with fossil fuels (coal or natural gas). Two recent levelized cost of electricity studies worthy of review are: University of Texas's Study[30] and Lazard's[31] private research.

WHO PAYS? The costs associated with EPA's methane regulations, new ozone standards that would likely require electric motors, and the new natural gas safety/storage standards are all new. It is doubtful that electric utilities budgeted for these costs when penciling out the costs of conversion to gas. Further, PHMSA is expected to issue a "mega rule" in early 2017 to address much broader pipeline safety standards not discussed in this paper. All of these maintenance and upgrade costs will easily exceed many hundreds of million dollars nationally. These costs will be expected to emerge before PUCs and at FERC for cost recovery.[32] It is unclear whether these adjudicatory bodies will opt to have all gas customers pay for the costs or whether electric utilities will pay a larger share of the costs. These maintenance costs might be negligible for some utilities resulting in a preference for natural gas over coal. But for some utilities with few industrial customers or declining populations, these new costs for "all in" natural gas generation can be quite expensive. For some municipal or coop utilities, with decreasing populations or shrinking industrial customers, these costs can be difficult to explain. Some customers may become frustrated if they read that natural gas "is cheap" but wonder why are they paying more for electricity needing more infrastructure for reliability reasons.

CONCLUSION Natural gas generation has many attributes and is generally environmentally preferable to coal when weighing climate issues. Setting CO_2 aside, coal-fired can be close to par with natural gas for utilities given air issues. Capital expenditures for NGCC buildouts are far lower than for new coal or nuclear power. New NGCC plants have faster ramping capabilities for backing up renewables. But NGCC plants have not had the longevity of coal plants over the last forty years. Even if U.S. EPA changes some of its anti-coal policies, the public may not accept them. While natural gas prices have increased in the last year, the price is, *for now*, preferable to coal[33]. Even if these prices are not expected to last, they are currently advantageous. However, natural gas generation is more complex logistically, at least for the next 5-10 years as infrastructure is not yet fully ready, because the fuel is not immediately available on site. Recent EPA and PHMSA regulations mean that there may be more supply and distribution issues that could cause some short term and localized reliability concerns for some power plants. While these service problems might not be as common in states like Texas, Oklahoma, and New Mexico where there is a tremendous amount of natural gas pipeline and storage infrastructure, it may be more problematic in New England, Arizona, and in Florida because of its unique peninsula shape, geology, and cultural expectations that the land be available for tourism. For some states, having fuel diversity may remain the best answer.

Natural gas conversion issues are not insurmountable but do require considerable planning, coordination and community acceptance.

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 www.theresapughconsulting.com or theresapughconsulting@gmail.com Theresa Pugh's analysis is a reflection of 13 years' experience in the electric utility industry and seven years in the oil and gas industry—including midstream pipelines.

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[30] http://energy.utexas.edu/the-full-cost-of-electricity-fce/fce-publications/lcoe-white-paper/

[31] Although proprietary the overview may be found at https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/

[32] Established under the 2015 Columbia Pipeline case and FERC policy statement PL15-1. See https://www.ferc.gov/whats-new/comm-meet/2015/041615/G-1.pdf

[33] Natural gas price is dictated by many factors not covered in this paper including the cost of credit, increased production costs due to environmental regulations, access to western lands, LNG exports to Mexico, increased industrial demand, technology advancements for drilling efficiencies, and domestic and international market prices. This paper does not address new state subsidies for existing nuclear plants that would reduce natural gas demand in those states with nuclear power. Nor does the paper address reverse flows of natural gas pipelines or new factors making coal delivery by rail more costly due to fewer coal customers on that rail line, or the impacts on other recent environmental regulations on the coal mining industry. This paper makes no predictions on natural gas or coal prices for electric utilities.