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OMB via email to: oira_submission@omb.eop.gov

Oct 28, 2016

To: U.S. Environmental Protection Agency
   Attn: Ms. Brenda Shine
   Sector Policies and Programs Division, Refining and Chemicals Group
   Office of Air Quality Planning and Standards (OAQPS)
   Research Triangle Park, NC 27711

   OMB Desk Officer for EPA

Re: AGA’s Comments on EPA Proposed Information Collection Request (ICR) Submitted to
    OMB for Review and Approval: ICR for Oil and Gas Facilities, 81 Fed. Reg. 66962 (Sept
    29, 2016)

The American Gas Association (AGA) appreciates the opportunity to comment on the
Proposed Information Collection Request captioned above for oil and natural gas facilities
submitted to the White House Office of Management and Budget (OMB) for review and approval,
and noticed in the Federal Register on September 29, 2016 (Revised Draft ICR).

The American Gas Association, founded in 1918, represents more than 200 local energy
companies that deliver clean natural gas throughout the United States. There are more than 72
million residential, commercial and industrial natural gas customers in the U.S., of which 95% –
just under 69 million customers – receive their gas from AGA members. AGA is an advocate for
natural gas utility companies and their customers and provides a broad range of programs and
services for member natural gas pipelines, marketers, gatherers, international natural gas
companies and industry associates. Today, natural gas meets more than one-fourth of the United
States’ energy needs.
I. Introduction

AGA submitted comments to EPA on the initial draft ICR on August 2, 2016. To the extent that EPA has not addressed our concerns in the revised draft ICR, we reiterate those concerns here. In the following comments, we focus on revisions that are still needed to reduce unnecessary burdens in the Revised Draft ICR while providing the information EPA needs to develop existing source performance standards (ESPS) under section 111(d) of the Clean Air Act for oil and natural gas industry sources of methane and other greenhouse gas emissions.

As we noted in our August 2, 2016 comments to EPA on the initial draft ICR, AGA and our members have devoted significant resources over the years to obtain better natural gas emissions data and to modernize systems and practices to improve both safety and environmental performance. We were founding partners 20 years ago in EPA’s voluntary Natural Gas STAR program, and our members have participated in the program over the past two decades, sharing technologies and innovations for improving the environmental performance of natural gas systems. AGA’s Board of Directors has adopted a Commitment to Enhancing Safety,¹ and has approved voluntary AGA guidelines for reducing natural gas emissions.² As a result of our members’ commitment to safety and efforts to modernize their distribution infrastructure, the recent updated EPA Inventory of Greenhouse Gas Emissions issued April 15, 2016 shows that emissions from natural gas distribution have dropped an impressive 74 percent since 1990, even as the industry added over 300,000 miles of distribution mains to serve 17 million more customers, an increase of 30 percent in both cases.³ Similarly, our members have helped reduce emissions from natural gas transmission pipelines and compression. EPA’s recent GHG Inventory demonstrates that these efforts to modernize and upgrade facilities has helped reduce emissions from transmission and storage by 45 between 1990 and 2014.⁴ AGA members also showed up in force to support the launch of EPA’s new voluntary Methane Challenge program in March 2016.⁵ All 41 companies that volunteered as Founding Partners are AGA members, and more of our members plan to join later this year. In addition, AGA and its members have supported and participated in peer-reviewed scientific research studies to collect field measurement data on natural gas emissions – including the Lamb, Washington State University (WSU) multi-city

⁴ Id.
distribution study (2015) and the Zimmerle, Colorado State University (CSU) transmission and storage study (2015). AGA and several members are also participating in ongoing U.S. DOE National Energy Technology Laboratory (NETL) studies on methane emissions.

In light of our members’ track record for emission reductions, EPA excluded gas utility operations downstream of the local distribution company (LDC) custody transfer station – such as distribution system facilities, intrastate natural gas transmission and compression, intrastate underground storage, LNG peak shaving storage facilities and other facilities inside the LDC custody transfer station – from the scope of natural gas facilities subject to the recent GHG new source performance standards (NSPS) under 40 C.F.R. Part 60, Subpart OOOOa and Clean Air Act §111(b). This means that any ESPS under Clean Air Act §111(d) for natural gas facilities would also exclude gas utility facilities located downstream of the LDC custody transfer station.

The proposed ICR is intended to obtain data to help EPA develop a proposed ESPS for natural gas facilities, but we understand that under the ICR submitted to OMB, EPA still proposes to collect data from some facilities that will not be subject to the ESPS. For example, EPA apparently still proposes to send the ICR to 100% of the liquefied natural gas (LNG) peak shaving storage facilities, even though almost all such facilities are located downstream of the LDC custody transfer station and will thus be exempt from the ESPS. AGA estimates only 2-4 LNG storage facilities are located upstream of the LDC custody transfer station and will potentially be subject to the upcoming ESPS. We question the need to burden about 96 otherwise exempt facilities with an extensive data request in order to design regulations to cover approximately 4 facilities that may be subject to the upcoming ESPS. We question whether EPA can show that this is truly necessary to obtain a ‘statistically valid sample’ that will have practical utility in developing the ESPS. Nevertheless, if EPA can make this showing, and can take the steps we suggested in our August 2, 2016 comments to reduce the data collection burdens, our members are willing to assist in collecting data from otherwise exempt facilities in order to support data-driven regulatory decisions. Given the stringent federal pipeline safety controls and continuous monitoring at such facilities, we also anticipate that EPA will find that emission rates are already so extremely low, they likely do not warrant additional federal regulation to minimize natural gas emissions.

AGA is committed to supporting fact-based policy and regulatory decisions, and thus we support EPA’s overall goal of collecting good quality data to guide its regulatory decisions. AGA appreciates some changes EPA has made in the revised ICR, in particular we support the reduced burdens for tank testing. However, additional revisions are needed to reduce unnecessary burdens and to make the ICR reasonably tailored to its purpose.
II. Specific Comments on the Revised Draft ICR

A. AGA Supports the Threshold for Tank Testing, With Clarifications

EPA appreciates the addition of a threshold for requiring onerous on-site pressurized testing of tanks with separators for tanks and separators processing. The revised ICR would require such testing only for tanks and separators fed by a pressurized system that produce 10 barrels per day (bbl/day) of condensate liquids or pipeline fluids, with a proviso that if all tanks operated by a parent company in the transmission sector, transmission compression sector, or underground storage sector produce less than 10 bbl/day, then the parent company would be allowed to provide one sample for flash analysis for one tank at any of its facilities. This is helpful, and AGA supports this revision for tank testing, with a clarification explaining that this proviso would apply on a sector specific basis. For example, if a parent company has no tanks producing pipeline liquids above the 10 bbl/day threshold at any of its transmission compression stations, but has two tanks producing pipeline liquids above this threshold in its underground storage facilities, the parent company would test pipeline liquids at one sample tank at one of its compressor stations, and the company would test liquids produced from the two tanks producing 10 bbl/day at its underground storage facilities. In the alternative, if a parent company had no tanks producing pipeline liquids above the threshold at any of its underground storage or transmission compression facilities, the company would flash test just one tank – at either a transmission compression or underground storage facility. Providing examples such as this would help companies understand how they should respond to the ICR.

In addition, EPA should clarify that the threshold is 10 bbl/day rather than 5 bbl/day. The Part 2 survey “Tanks Separators” tab, and two docket documents (summary memo on comments and responses; detailed tabulation of comments and responses) all clearly indicate that the threshold is 10 bbl/day. However, the “Intro” tab indicates 5 bbl/day. To avoid confusion, EPA should correct the Intro tab to indicate the threshold is 10 bbl/day.

B. AGA Supports Auto-Filling Subpart W Data in the ICR, With Sandbox Testing

In the Revised Draft ICR, EPA proposes to avoid duplicative work by allowing e-GRRT to auto-fill applicable Subpart W data for a facility where responsive to an ICR survey worksheet question. We understand the cells would appear grey to the person filling out the survey, so they would not inadvertently go to the trouble of manually typing in the Subpart W data. AGA supports this method for reducing ICR burdens, if EPA provides an opportunity for Beta testing or sandbox testing through e-GRRT to reduce the risk of errors.

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6 See Introduction to Part 2, Revised Draft ICR, Tanks.
7 EPA-HQ-OAR-2016-0204-0124.
8 EPA-HQ-OAR-2016-0204-0125.
C. EPA Still Underestimates ICR Burdens, Especially Winter Deadline & Component Counts

1. Winter Reporting Deadline is Not Feasible - EPA Should Extend Until End of April 2017 - or June 2017 if Component and Pneumatic Counts are Retained

EPA did not heed or even respond to our August 2, 2016 comments asking the agency to extend the deadline for ICR responses. Instead, without explanation, EPA kept the same timeframe, which would require ICR responses to be submitted in February or March 2017. EPA asserted that this timeframe should be more feasible because the agency reduced some of the proposed reporting burdens. We agree that some burdens have been reduced for tanks. But EPA has retained the onerous and inexplicable requirement to send employees or contractors to each site to physically count each and every component – whether leaking or not – and regardless of safety hazards. This requirement pervades the Revised Draft ICR for several categories of sources, and it is a primary driver of estimated time and resource burdens. The Revised Draft ICR also would require detailed pneumatic device counts, which would significantly increase the burden of the ICR.

Imposing additional greenhouse gas reporting (GHG) requirements on natural gas companies in the winter is particularly unworkable and counter-productive. It is unworkable because winter months are the busiest time of year for natural gas utilities, pipelines, and storage facilities, due to peak demand during the winter heating season. The first quarter of every year is also when environmental reporting personnel must collect data to report on all environmental media – including their Subpart W methane and GHG reports. Environmental staff will be fully engaged with Subpart W and other environmental reporting through the end of March.

Yet, that is precisely when EPA plans to ask our members to respond to a very detailed questionnaire, and send employees or contractors out in the field to count and categorize components and pneumatic devices, and conduct tank flash testing. The proposed schedule calls for EPA to send the ICR questionnaires to facility operators at the beginning of November – apparently without waiting for OMB to review comments to be submitted by Oct. 31 -- and to require responses within 120 days – i.e. EPA is asking natural gas utilities and transmission pipeline companies to collect all the data and submit their completed ICR worksheets during November, December, January and February – during the holidays, the winter peak demand season and the first quarter environmental reporting crunch period. This is also a period when utilities may need to send personnel to assist other utilities impacted by a severe winter storm, pursuant to their mutual aid agreements. Companies are already stretched during this time of year. Our members would most likely have to hire outside contractors to perform the ICR work, as the company personnel are already more than fully occupied - especially during that time of year. However, company personnel would still need to plan and manage the activities. It takes time to draft contracts, obtain legal review and get contracts in place, which would further reduce the time available to perform the ICR work. This would also increase costs, particularly if many
operators are trying to hire the same limited pool of expert contractors at the same time. Moreover, even if the outside contractors have the requisite professional expertise, they will not be as familiar with company facilities and operations as internal personnel. So, EPA’s proposed schedule could also result in a greater error rate in the data unless internal personnel are allowed time to better review and guide the contractors’ work.

We raised this concern in our August 2016 Comments, but EPA’s Response to Comments document provides no explanation for ignoring the burdens of requiring natural gas utilities and pipeline companies to respond to the ICR during the winter peak heating season and crunch time for Subpart W and other environmental reporting. The only response they provide about rejecting a call to extend the response deadline relates to revisions in the ICR for upstream production, not for the types of facilities operated by natural gas utilities and interstate pipelines. There is no need to impose such tight deadlines, unnecessarily driving up costs and potentially reducing data quality. Simply extending the ICR response until at least the end of April 2017 would allow facility operators 30 days after the peak winter heating season and after filing their Subpart W and other environmental reports at the end of March, so that they could use more internal personnel (once they are freed up from the winter peak operational tasks and first quarter reporting deadlines).

In our August 2, 2016 Comments, we asked EPA to extend the deadline until the end of June 2017. However, if EPA clarifies that there is no need to physically count and categorize all components and pneumatic devices in every facility and allows reporters to use reasonably available data or engineering estimates of relevant components, then we believe it will be feasible to respond to the ICR by the end of April 2017. To the extent some on-site data collection is still required, extending the deadline into the spring would also help address safety concerns by allowing operators to avoid sending personnel out during the cold and icy conditions of winter to count and assess equipment that would otherwise remain untouched. To the extent contractors are needed, the longer time frame would make it easier and less costly to obtain outside assistance. AGA therefore urges EPA to allow until the end of April 2017 to respond to the ICR. If facility visits are required for pneumatic device and component counts, EPA should allow additional time until the end of June 2017.

2. EPA Still Underestimates Time and Costs for Responding to the ICR

EPA estimates the “Industry Burden and Cost for Responding to the Part 2 Questionnaire” based on the estimated number of hours EPA believes would be required to perform the required tasks by an engineer, operator, manager and/or clerical worker. Rates for an engineer are estimated to be $148.95 per hour, while the cost for an operator are estimated to be $65.10 per hour. EPA estimates each task would take approximately 1-6 hours per equipment type worksheet per facility ICR.

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9 See In Attachment 4A to the Revised Draft ICR Supporting Statement.
In our August 2, 2016 Comments, AGA provided a chart showing the time our member company environmental engineers estimated would be required for the tasks called for in Part 2 of the June 2016 Proposed ICR. Below, we provide their updated estimates for burdens on each underground storage, LNG and transmission compression facilities to respond to Part 2 of the Revised Draft ICR submitted to OMB. Companies receiving ICRs for multiple facilities would multiply burdens accordingly. We assume below that the 10 bbl/day tank testing threshold would apply, but that EPA would still require operators to physically count and categorize each and every component and pneumatic device at every facility subject to the ICR. For estimated ICR burdens for transmission pipeline facilities which can extend many hundreds of miles, we refer you to the comments filed in this docket by the Interstate Natural Gas Association of America (INGAA) on October 27, 2016.

<table>
<thead>
<tr>
<th>TABLE 1 – AGA Estimated Industry Burden for Responding to ICR Part 2 Questionnaire</th>
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<tbody>
<tr>
<td><strong>Equipment Type</strong></td>
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<tr>
<td><strong>(Excluding Transmission Pipeline Facilities)</strong></td>
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<tr>
<td>Storage Tank Separators</td>
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<td>Pneumatic Devices</td>
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<tr>
<td>Dehydrators</td>
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<tr>
<td>Equipment Leaks</td>
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<td>Component Counts</td>
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<tr>
<td>Compressors</td>
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<tr>
<td>Blowdowns</td>
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<td>Control Devices</td>
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*Note: EPA’s Attachment 3B erroneously refers to the storage tanks/separators worksheet collection activity as “2C.” This a confusing but probably inadvertent error. The EPA burden and cost table would be less confusing if it referred to the actual worksheet section number for tanks and separators – 2F.
The above table includes estimates of actual hours that are based on ranges estimated for AGA member transmission compression, underground storage and LNG facilities. AGA believes these burdens could be reduced or at least the cost could be reduced by allowing more time and by reducing the scope of requested information as we suggest in these comments.

For 2G and 2J, the survey implies that pneumatic and component counts are required for *transmission pipeline* facilities. If this is the case, then the time and cost burdens of the ICR would be far higher. Counting pneumatic devices and components along transmission pipelines would be a difficult and very impractical requirement – especially in the winter in the north. In its response to comments document, EPA indicates a “pipeline facility” will be limited to a single state to simplify the required reporting. However, this is still a difficult task because a transmission pipeline within a state could include hundreds of miles of pipe with occasional metering. EPA has not considered the significant costs associated with such an undertaking. Moreover, while EPA notes the “state” limit in the response to comments, EPA does not indicate any such limitation in the Part 2 template. This should be clarified. Obviously, costs would multiply if pneumatic and component counts were required for interstate transmission pipelines across multiple states.

3. **Eliminate Requirement to Count Total Number of Components**

EPA should eliminate the requirement in the Revised Draft ICR Part 2 equipment leak questionnaire worksheet to count the total number of components at a natural gas facility that come into contact with 5% or more methane by weight, and the total number of components monitored for leaks in the most recent monitoring survey. EPA’s caption for the work sheet states that the report should be “based on actual component counts.” Pipeline quality natural gas is 95% or more methane, so this requirement to count components that come into contact with “5% or more methane” in effect requires counting all the thousands of components at a natural gas transmission compressor station, natural gas transmission line, underground storage facility, LNG peak shaving storage facility, or LNG import/export terminal, even if none of them are leaking or venting. As we explained in our August 2, 2016 Comments, this information is not currently available, and collecting it would be a seriously unnecessary waste of time and money. EPA provides no explanation why the agency needs to know the exact, total number of components at a facility or why this could possibly have any practical utility for developing ESPS regulations to monitor and reduce methane emissions at existing natural gas facilities.

Although a detailed list of components might provide a large data base on which the agency could perform a statistical review to estimate emissions, this data would have *no practical utility* without an extensive campaign to quantify the amount of emissions (if any) from each component. Further, it is questionable how useful such a massive undertaking would be, given that components are upgraded, repaired and replaced on a regular basis -- not only to reduce or avoid gas loss, but also for planned maintenance, improved operation or system upgrades.
If EPA wishes to have a measure of the size of a facility in relation to its number of leaking components or level of emissions, there are less burdensome alternatives using data readily available in a company’s records, such as asking for the volume of natural gas throughput at the facility or storage capacity or amount of natural gas actually stored in a given year. We would be happy to work with EPA to develop alternatives that work for both operators and EPA.

If it is not EPA’s intention to require operators to send workers out to count each and every component at a facility, but instead to require reporting the estimated number of components based on readily available records or engineering estimates, then the agency should explicitly say this in the ICR and related instructions. The phrase “based on actual component counts” should be deleted from the ICR worksheet.¹⁰

4. AGA Supports Requesting Information on Routine Inspections, as Revised

AGA does not object to the request in the equipment leak worksheet asking whether the operator conducts routine inspections at a given facility, and if so, the inspection frequency and monitoring method used. We appreciate EPA’s effort to respond to our August 2016 comments on the survey “picklist values” relating to the equipment leaks. As we requested, Attachment 1A in EPA’s Supporting Statement has revised EPA’s picklist number 38 to include Hi-flow sampler as an option for survey responses regarding the monitoring method used in a leak survey. We also appreciate EPA’s decision to retain the option to pick “other (specify)” to allow the operator to specify another monitoring method. The pick list options for “leak definition” (pick list number 39) were previously limited to parts per million volume (ppmv) levels from 500 ppmv up to 10,000 ppmv, plus “any visible emissions using OGI.” We asked EPA to add an option to pick 12,500 ppmv if they used a methane detector set to alarm (for safety purposes) at 25% of the lower explosive limit (LEL), which is equivalent to 12,500 ppmv. In case an operator has data based on Hi-Flow measurements, AGA suggested in our August comments to add a pick list option for cubic feet per second or minute (i.e. a flow rate measured with a Hi-Flow device). EPA did not make those two changes, but instead added a pick list option under leak definition for “Other (specify).” AGA supports that addition as it addresses our concerns.¹¹

5. EPA Should Reduce Reporting Burden for Low-Emitting LNG Facilities

AGA especially urges EPA to eliminate the burdensome total component and pneumatic device counts especially for Liquefied Natural Gas (LNG) facilities, because the burden so far outweighs any practical utility for EPA’s goal of developing existing source performance standards (ESPS) pursuant to Clean Air Act 111(d) for natural gas facilities. First, more than 95% ¹⁰ See EPA’s Information Collection Request Supporting Statement dated Sept. 22, 2016 (Supporting Statement), Attachment 3L, section 2 Equipment Leak Inventory Information, p. 87.
¹¹ See Supporting Statement, Attachment 1A, ICR Survey Picklist Values, pp. 32-33.
of existing LNG peak shaving storage facilities will be excluded from the source category subject to the ESPS, because they are inside the LDC custody transfer station, and this type of facility (when new or modified) is excluded from the source category subject to the 111(b) NSPS. Second, due to their inherent operations as well as stringent requirements under federal pipeline safety regulations, greenhouse gas emissions from both LNG peak shaving storage facilities and LNG import/export terminals are already extremely low, as we explain below.

a. LNG Leaks, if any, Are Visible as Small Vapor Clouds and Promptly Fixed

By their very nature, LNG facilities make it easy to spot and address any leaks promptly. LNG storage facilities and LNG import/export terminals operate at cryogenic temperatures (less than 100 degrees Fahrenheit). Leaks are obvious to the naked eye, because a small vapor cloud develops at the point of leakage as the moisture in the air condenses.

b. Frequent Leak Surveys and Repairs Are Already Required by Federal LNG Rules

The Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has adopted regulations for LNG facilities under 49 CFR Part 193, section 2013, that are even more stringent than those for transmission lines under Part 192. Natural gas transmission pipeline operators are required under 49 C.F.R. Part 192 Section 706 to perform leak surveys as often as two to four times per calendar year, and section 711 requires transmission operators to make permanent repairs to discovered leaks when feasible. Manned facilities are patrolled at least once per shift during the day, and unmanned satellite facilities that are only used during seasonal peak operations are still patrolled at least twice per month. Personnel conducting these on foot patrols check for visible vapor clouds and use hand-held methane detection devices.

c. Federal LNG Safety Regulations Require Continuous Fixed Point Gas Detection

Due to stringent federal safety regulations, LNG facilities are monitored constantly by fixed point gas detection equipment which can set an alarm in the LNG facility control room – in addition to the regular foot patrols described above. PHMSA’s LNG regulations under 49 C.F.R. Part 193 adopt by reference provisions from the 2001 version of the National Fire Protection Association (NFPA) 59A, Standards for the Production, Storage, and Handling of Liquefied Natural Gas (LNG) to require all LNG facilities (peak shaving storage and vaporization, satellite, and import terminals) to install fixed point leak and flammable gas detection systems, to monitor those fixed point systems continuously, and to repair any leaking or defective component.12 NFPA 59A is an American National Standards Institute (ANSI) accredited consensus standard developed by the NFPA, subject matter experts, government regulators, industry stakeholders, manufacturers, insurance industry representatives, fire fighters, and the public. The NFPA 59-A Standard is revised and updated every 3-4 years to ensure that it reflects the latest technology and practices.

and PHMSA periodically amends 49 C.F.R. §193.2013(g) to adopt provisions added in more recent iterations of NFPA 59-A.

Pursuant to this federal regulation, LNG facility operators have installed gas/leak detection equipment that performs continuous monitoring of field conditions and upon detection is required to alarm in the field and at an attended control room at 25% of the lower flammable limit (or lower explosive limit – LEL) of methane. The LEL is 5% methane in air; 1.25% (25% of LEL) or 12,500 ppmv is the required gas detection alarm limit pursuant to the NFPA 59A LNG Standard.

Furthermore, these facilities are required to have trained and qualified operating personnel who monitor the installed detection systems and conduct regular facility inspections several times each day, including process post-cool down field checks to confirm that system integrity has been maintained. Due to notification by the monitoring system to the attended control room, if leakage does occur, operating personnel are alerted immediately and the leak is quickly addressed by adjusting the equipment or stopping the process, thereby avoiding any significant emissions.

d. LNG Valves by Design Have Minimal to No Leakage

Due to the combined conditions of extreme temperature and pressure, valves (gate, ball, butterfly, etc.) in LNG service are typically designed with extended bonnets and utilize multiple rings of V-ring style stem packing, made typically of PTFE (Teflon). This style of packing is very resilient and has high sealing qualities, thereby greatly minimizing if not eliminating fugitive emissions.

e. LNG Safety Relief Devices Minimize or Eliminate Emissions

Due to extreme operating conditions, the majority of safety relief valves in LNG service are soft seated style valves, which greatly minimizes or eliminates premature leakage at pressures below the valve opening set point. Additionally, relief valves in the LNG industry in the U.S. are maintained at a very high level of performance, as each relief valve at LNG facilities is required by the federal LNG code, 49 C.F.R § 193.2619, to be inspected and tested annually for lift pressure and positive reseating, which indicates that it operates properly and is not leaking. PHMSA inspects safety valve testing records to confirm that the facility’s annual testing of valves has met the regulatory requirements for test frequency and valve performance.

f. LNG Compression Equipment Differs Internally and is Far Lower Emitting

LNG facilities use reciprocating and centrifugal compressors for a limited number of purposes, which include boil-off compression, and as refrigerant and boost compression in liquefaction processes. Compressors are not used (and not needed) to compress vaporized LNG in order to move natural gas from LNG storage facilities to the distribution send-out system.

From a cursory inspection on the outside, reciprocating compressors at LNG facilities may appear similar to reciprocating compressors more familiar to EPA, such as those located at transmission compressor stations. However, reciprocating compressors at LNG storage facilities are quite different internally, due to the materials utilized to seal piston rod packing to limit leakage past the piston rods. Reciprocating compressors used at LNG facilities for boil-off compression, liquefaction refrigeration compression and
liquefaction stream boost generally utilize non-lubricated cylinders and rod packings to eliminate the risk of lubricants being introduced into the process gas stream, causing contamination of the stream with oil residue, which would freeze the oil in critical components such as heat exchangers, operating at temperatures as low as minus 260 degrees Fahrenheit. These non-lubricated applications typically utilize piston ring, and rod packing materials of varying graphite, PTFE (Teflon) blends which are very resilient and have high sealing qualities, thereby greatly minimizing fugitive leak emissions from the compressor rod packing cases.

Centrifugal compressors are typically utilized at LNG facilities as liquefaction process refrigerant compressors. Again, while externally they may resemble typical centrifugal compressors that are becoming more common in gas transmission compressor stations, these centrifugal refrigerant compressors are typically quite different internally with respect to their shaft sealing design, using very sophisticated oil film (wet) sealing or dry elements, which greatly reduce or eliminate leakage. The outer case seal areas and the seal oil drains are directed back to the compressor suction after demisting takes place. Because the outer case seal area and seal drains lead back to the compressor suction, there are no gases purposely vented to the atmosphere.

g. LNG Pump Design Precludes Emissions

The majority of LNG pumps at LNG facilities are not open to the atmosphere, either vertical turbine multistage pumps installed in pump wells submerged within the LNG tank, or pumps for which the motor and the pump are fully enclosed and submerged in LNG in the pump can. These pump types do not require pump shaft seals and are not open to the atmosphere, so they generate no fugitive emissions. For those facilities utilizing LNG pumps with external motors not enclosed within the pump can, and with pump shaft sealing, the seals are closely monitored, and if leakage were to occur, the pump would be shut down and repairs to the seal performed. Due to the level of redundancy of systems and equipment, LNG facilities are generally equipped with a number of spare pumps, allowing shutdown of any pump experiencing a seal failure, while maintaining facility operations.

h. Based on LNG Design and Safety Regulations, EPA should Reduce ICR Burdens at LNG Facilities

In light of these design differences and the overlapping, stringent LNG monitoring and repair requirements under federal pipeline safety regulations, there does not seem to be any practical utility in collecting such extensive data from over 90 LNG facilities that will not even be subject to the ESPS, to develop emission standards for the few remaining LNG facilities outside the LDC custody transfer station – particularly since it is unlikely any such ESPS would result in any significant emission reductions beyond those already achieved through stringent LNG design standards and federal pipeline safety regulations. Given the heavy resource burdens for sending personnel to count all equipment components in all LNG facilities, and the low practical utility of the resulting data for developing an ESPS for the few LNG facilities outside the LNG custody transfer station, AGA urges EPA at a minimum to eliminate from the ICR any requirement to count total components at a facility or the number of components monitored.
6. **AGA Appreciates the Opportunity to Check the Proposed Mailing List, but EPA Should also Specify that it will Send ICR Letters to the e-GGRT Designated Representative**

In response to comments on the June draft ICR, EPA has made the draft ICR Mailing List available so that affected companies can review and correct the facility mailing addresses. However, we reiterate our concern that the ICR letters should not be mailed to individual facility locations – such as individual LNG facilities or transmission compression stations. Environmental compliance and reporting staff are typically located at corporate or subsidiary headquarters, not at individual field locations. To ensure that these letters do not go astray, particularly at unmanned facilities, EPA should mail or email each ICR letter to the appropriate company e-GGRT Designated Representative for the company that operates the facility targeted by the ICR. This will increase the probability of a high response rate to the ICR letters, and allow EPA to reduce the total number of ICRs it sends.

7. **ICR definitions Should be Consistent with Methane NSPS and GHGRP**

In several instances, EPA has used terms that are either not defined or are defined in a manner that conflicts with the definitions EPA has used in the GHGRP regulations and/or the methane NSPS final rule, 40 C.F.R. Part 60, Subpart OOOOa. This makes it difficult or impossible to use data already gathered and logged following other established EPA GHG definitions. Obviously, this would result in unnecessarily increasing costs and burdens for responding to the Part 2 survey. To reduce the burdens of this ICR, AGA urges EPA to provide clear definitions for all key terms that align with GHGRP definitions if available, or if not, then with definitions used in the OOOOa NSPS. This will allow operators to use available data as much as possible to respond to the ICR. Clear definitions that set clear boundaries regarding what is in and what is excluded from a segment, a source, or a type of equipment will also help save time, as operators will not have to waste time trying to decipher the meaning of undefined or otherwise ambiguous terms. For example, EPA’s Revised Draft ICR adds several new categories of definitions for pneumatic devices beyond those listed in Subpart W. At most, the ICR should request counts for the three pneumatic device categories already listed and defined in Subpart W.

Pneumatics are a minimal emissions source for transmission and storage operations (based on data from the 2011 – 2014 Subpart W reports). Subpart W already requires reporting continuous and intermittent bleed devices. The Revised Draft ICR would essentially require reporters to split the same trivial emissions in a different manner, providing limited information for EPA’s purposes, while imposing significant burdens on facility operators to send personnel out in the field to conduct a tedious and time-consuming count. As noted in INGAA’s comments, it would be particularly problematic, if not impossible, to count and categorize pneumatics (and other components) along hundreds or thousands of miles of natural gas transmission pipelines. As the burdens would far outweigh any benefit, EPA should delete the requirement to count and categorize pneumatic devices for transmission, storage or LNG facilities.

8. **Component and Pneumatic Counts Should Not Apply to “Natural Gas Transmission Pipeline Facilities”**

The “boundary” for the “natural gas transmission pipeline facilities” segment is unclear. If pneumatic device and equipment leak ICR worksheets also apply to transmission pipeline facilities that include ancillary equipment such as metering or pressure regulating equipment located along a pipeline, it would
become exorbitantly costly to gather that pneumatic device and equipment leak data for tens of thousands of pipeline miles. As we explain above, the burden would far exceed the usefulness of the information EPA would collect. EPA should clarify that the pneumatic device and equipment leak worksheets do not need to be completed for transmission pipelines.

AGA appreciates the opportunity to comment. Please contact me if you have any questions.

Respectfully Submitted,

Pamela Lacey
Chief Regulatory Counsel
American Gas Association
400 N. Capitol St., NW
Washington, DC 20001
202-824-7340
placey@aga.org