INFORMATION COLLECTION REQUEST
SUPPORTING STATEMENT

EPA ICR No. 2548.01:

INFORMATION COLLECTION EFFORT FOR OIL AND GAS FACILITIES

Sector Policies and Programs Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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PART A OF THE SUPPORTING STATEMENT

INFORMATION COLLECTION EFFORT FOR OIL AND GAS FACILITIES

1. Identification of the Information Collection

1(a) *Title of the Information Collection*

"Information Collection Effort for Oil and Gas Facilities." This is a new Information Collection Request (ICR).

1(b) *Short Characterization*

This information collection is being conducted by the U.S. Environmental Protection Agency's (EPA's) Office of Air and Radiation (OAR) pursuant to section 114 of the Clean Air Act, as amended ("CAA" or "the Act"), to assist the Administrator of EPA in developing emissions standards for oil and gas facilities pursuant to section 111 of the Act. Section 114(a) states, in pertinent part:

> For the purpose...(iii) carrying out any provision of this Chapter...(1) the Administrator may require any person who owns or operates any emission source...to-. . .(D) sample such emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods and in such manner as the Administrator shall prescribe); (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical.. .(G) provide such other information as the Administrator may reasonably require...

The non-confidential information submitted in response to this information collection will be made available to the public.

In January 2015, as part of the Obama Administration's commitment to addressing climate change, the EPA outlined a number of steps it plans to take to address methane and smog-forming volatile organic compound (VOC) emissions from the oil and gas industry, in order to ensure continued, safe and responsible growth in U.S. oil and natural gas production. As a result, EPA proposed and finalized New Source Performance Standards (NSPS) for the oil and gas industry to achieve both methane reductions and additional reductions in volatile organic compounds (VOCs). The EPA has also committed to develop standards of performance for existing oil and gas sources.

This information collection request is necessary to develop nationally applicable regulations to reduce methane emissions, and, as appropriate, emissions of other air pollutants from oil and gas sources.

The oil and gas industry includes a wide range of different types of facilities or industry segments. The oil and gas industry segments considered in the framework of this information collection request include: onshore petroleum and natural gas production; onshore petroleum and natural gas gathering and boosting; onshore natural gas processing; onshore natural gas transmission compression; onshore natural gas transmission pipelines; underground natural gas storage; LNG storage; and LNG import and export equipment. It is estimated that there are almost 1.4 million producing oil and gas wells at approximately 698,800 well sites (onshore production facilities) in the United States (U.S.). There are approximately 5,000 gathering and boosting facilities, 668 processing facilities, 1,400 transmission compression facilities, 939 transmission pipeline facilities, 418 underground natural gas storage facilities, and 111 liquefied natural gas (LNG) storage or import/export facilities.

Information on greenhouse gas (GHG) emissions from oil and gas facilities is collected as part of the EPA's Greenhouse Gas Reporting Program (GHGRP) under 40 CFR Part 98 Subpart W, Petroleum and Natural Gas Systems. However, there is a reporting threshold, and the reporting requirements do not currently cover certain emission sources (i.e., gathering and boosting and transmission pipelines facilities; these industry segments will begin to report emissions in 2017 for emissions occurring in the 2016 calendar year), and therefore the data do not represent the entire universe of emissions from oil and gas systems. The GHGRP also aggregates production level reporting at a basin level. Further, the GHGRP does not collect information on design, performance, and costs of mitigation measures. This information is necessary to evaluate the scope, design, and potential impacts of future regulation of this industry, in particular, of methane emissions from existing oil and gas facility sources.

There will be two parts to the information collection that will be issued simultaneously. Part 1, referred to as the operator survey, is specifically designed to obtain comprehensive information from onshore petroleum and natural gas production facilities to better understand the number and types of equipment at production facilities. Part 1 seeks to collect information regarding production operators (e.g., facility name, address and contact information) as well as information on the location and types of equipment (e.g., number of wells, tanks, dehydrators and compressors) present at well surface sites and centralized production surface sites. The definitions of well surface sites and centralized production surface sites are expected to align with the definition of facility commonly employed when permitting new and existing sources. Part 1 will be sent to all known operators of oil and gas production wells and will allow the Agency to obtain the information necessary to identify and categorize all potentially affected oil and gas production facilities. The operators will complete the Part 1 survey and provide equipment counts for all production facilities that they operate except for facilities selected to complete Part 2. Part 1 is not expected to contain any confidential business information. This operator survey may be submitted either electronically or through hard copy responses. The submission requires the owner or operator to certify that the information being provided is accurate and complete.

Part 2, referred to as the detailed facility survey, will be sent to selected oil and gas facilities (production, gathering and boosting, processing, compression/transmission, pipeline, natural gas storage, and LNG storage and import/export facilities) based on statistical sampling method described in Part B of this Supporting Statement. Part 2 will collect detailed, unit-specific information on emission sources at the facility and any emission control devices or management practices used to reduce emissions. Most of the information requested under Part 2 is expected to be available from company records and would not require additional measurements to be performed. However, selected data elements must be completed based on actual component equipment counts (specifically, pneumatic device counts and equipment leak component counts) or measurement data (specifically, separator/storage vessel flash analyses). If this information is not directly available for a facility, the respondent must collect and report this information (count equipment components and/or sample and analyze tank feed streams) as part of this information collection. Part 2 is expected to include information that oil and gas facilities consider to be confidential and the survey must be completed and submitted electronically via the EPA's Electronic Greenhouse Gas Reporting Tool (e-GGRT).

The EPA estimates the cost of Part 1 and Part 2 of the information collection will be 284,751 hours and $42,453,050.

2. Need for and Use of the Collection

2(a) *Need/Authority for the Collection*

Collectively, oil and gas facilities are the largest industrial emitters of methane in the U.S. In January 2015, as part of the Obama Administration's commitment to addressing climate change, the EPA outlined a number of steps it plans to take to address methane and smog-forming volatile organic compound (VOC) emissions from the oil and gas industry. The EPA has recently promulgated NSPS for the oil and gas industry to achieve both methane reductions and additional reductions in VOCs (40 CFR part 60, subpart OOOOa; see 81 FR 35824). The EPA is also now beginning the process of development of standards of performance for existing oil and gas sources. Section 111(d) of the Act provides a cooperative federalism approach to establishing standards of performance for existing sources. Under this approach, EPA establishes guidelines that identify the emission performance states must require their sources to achieve, and states then submit plans for EPA review and approval, which establish standards of performance that achieve that emissions performance.

Currently available information for oil and gas facilities is incomplete to assess what may be the best approach for regulating these sources. As noted previously, the EPA collects information on the GHG emissions from oil and gas facilities under Subpart W of the GHGRP. However, the GHGRP does not collect information on costs or technical feasibility of mitigation measures. This information is necessary to evaluate the scope and potential impact and design of future standards of performance for oil and gas facility sources, both for existing sources and sources not covered by the standards for performance for new and modified sources. There are also differences in the definition of "facility" in the GHGRP for the oil and gas production facilities as compared to the way we have defined facility under our NSPS regulations. Additionally, certain states have moved forward with their own rules and have developed information needed for their own purposes, but this information is not sufficient for a national rulemaking. Thus, it is necessary to collect specific information for oil and gas production facilities to understand the number of affected facilities and to assess potential alternative regulatory approaches.

2(b) *Use/Users of the Data*

The data collected from Parts 1 and 2 will be used to determine the number of potentially affected emission sources the types and prevalence of emission controls or emission reduction measures used for these sources at oil and gas facilities nationwide, and potential costs for those measures and controls. Due to the large number of potentially affected sources in most of the industry sectors, a sufficient number of facilities from each sector will be surveyed to collect this information and fill data gaps for setting emission limits and evaluating the emission impacts of various regulatory options for standards of performance for oil and gas facilities. The data collected in this ICR will also the used to support the review of National Emissions Standards for Hazardous Air Pollutants (NESHAP) affecting the oil and gas industry, such as 40 CFR part 63 subparts HH and HHH and to support the review of other NSPS, such as 40 CFR part 60 subparts KKK, LLL, and OOOOa.

3. Non-duplication, Consultations, and Other Collection Criteria

3(a) Non-duplication

The Agency recognizes that some of the information requested may already be included in the submittals being made by individual companies to the GHGRP. Therefore, the Agency reviewed each survey question to determine if the information is already included in the GHGRP. Where the information requested is identical to that collected under the GHGRP, facilities that report under the GHGRP are only required to provide their GHGRP ID number and may skip the questions that are duplications of information being reported under the GHGRP. However, a production facility under the GHGRP includes all wells owned or operated by a person within a single basin, which may include properties that are not contiguous or adjacent. While some of the production information is reported at the sub-basin level under the GHGRP, this information is still expected to be an aggregation of the production across numerous affected facilities. We also have different definitions for facilities in the gathering and boosting industry segment. In these cases, the reporting of sub-basin level information under the GHGRP is not identical to reporting facility level production information under this ICR where respondents must provide the information at the facility level considering the CAA affected source definition (contiguous or adjacent properties under common ownership or control).

Some of the information requested may also be included in submittals by individual facilities pursuant to operating permit applications, state reporting requirements, or lease requirements. Even when the permit is available, often the unit-specific information is unavailable. Typically, the information requested under this electronic survey is not available in a consistent and usable format from these other sources.

3(b) *Public Notice Required Prior to ICR Submission to OMB*

This ICR is being submitted to the Office of Management and Budget (OMB) as required by the Paperwork Reduction Act of 1995 (PRA) and the subsequent rule issued by the OMB on August 29, 1995 (60 FR 44978). Public comments were previously requested via the Federal Register (81 FR 35763) on June 3, 2016, during a 60-day comment period. Sixty-six comments were received, which are summarized and addressed in a separate document included with this ICR. The supporting statement was then revised based on the comments received during this initial public comment period and the revised supporting statement was submitted for OMB review with a concurrent 30-day comment period starting on September 29, 2016 (see 81 FR 66962). This final supporting statement includes additional revisions to address both OMB's and the public's comments received during the second comment period.

3(c) *Consultations*

The Agency worked with EPA Regional Offices and State delegated authorities to understand data needs and to solicit comment on the questions to be included in the draft ICR. The Agency also conducted a number of webinars for environmental groups, industry representatives and state agencies to inform various stakeholders regarding the planned ICR. Initial feedback that was received from these efforts was considered in the development of the draft ICR. In addition, as noted previously, the public had an opportunity to provide detailed comments on the draft ICR. During this period, the EPA met with several different stakeholders to further discuss their comments on the ICR. The EPA also visited a number of oil and gas facilities across several different industry segment to better understand their operations and their concerns regarding this ICR. The EPA has considered and addressed those comments, as appropriate, through revisions in the ICR. A summary of the comments and EPA's responses is located in Docket ID No. EPA-HQ-OAR-2016-0204. Docket ID No. EPA-HQ-OAR-2016-0204 also includes meeting minutes for the various meeting held with stakeholders and site visit trip itineraries.

3(d) *Effects of Less Frequent Collection*

This ICR is a one-time information collection. Part 1 will require the owner/operator of each potentially affected oil and gas production facility to complete a short survey of the numbers of wells, separators, storage tanks, and compressors at each centralized production surface site and each well surface site. This information is critical to understanding the universe of facilities and the impacts of potential future regulations. Part 2 employs a statistically-based sampling approach to collect unit-specific operation and control system information. This information is needed to understand the types of control systems used at facilities, the prevalence of use, costs, and the emissions reductions that can be achieved through alternative regulatory strategies.

Because this is a one-time information collection, the Agency could not consider less frequent information collection. However, in order to reduce the overall burden of the ICR, the Agency is proposing a statistically-based sampling approach for Part 2. The Agency considered the accuracy of the industry characterization of processing units and controls obtained from the survey needed to make informed decisions. The Agency considered sampling approaches based on acceptable error margins. While the Agency would prefer to have the smallest error possible, reducing the acceptable error margin increases the number of facilities that would need to be included in the sampling survey. After evaluating the impacts of sampling approaches, the Agency developed the sampling approach described in Appendix B based on acceptable error margins. Surveying fewer facilities in the sampling approach would increase the error associated with data evaluations conducted using the collected data and could result in the Agency making incorrect conclusions based the uncertainty associated with a more limited data set.

3(e) *General Guidelines*

This ICR will adhere to the guidelines for Federal data requestors, as provided at 5 CFR 1320.6.

3(f) *Confidentiality*

Respondents will be required to respond under the authority of section 114 of the Act. All information submitted to the Agency in response to the ICR surveys will be managed in accordance with applicable laws and EPA’s regulations governing treatment of confidential business information at 40 CFR Part 2, Subpart B. Any information determined to constitute a trade secret will be protected under 18 U.S.C. § 1905.

3(g) *Sensitive questions*

This section is not applicable because this ICR will not involve matters of a sensitive nature.

4. ***<u>The Respondents and the Information Requested</u>***

4(a) *<u>Respondents/NAICS Codes</u>*

Respondents affected by this action are owners/operators of oil and gas facilities. There are several industry segments that may be considered oil and gas facilities. This ICR is specifically requesting information for facilities in the following industry segments: onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore natural gas transmission compression, onshore natural gas transmission pipelines, underground natural gas storage, LNG storage, and LNG import and export equipment. The ICR is not requesting information for the offshore petroleum and natural gas production industry segment or the natural gas (local) distribution industry segment. Table 1 below presents some examples of potentially affected entities according to NAICS code. Table 1 is not intended to be exhaustive, but rather provides a guide for respondents regarding facilities likely to be affected by this ICR.

Table 1. Examples of Potentially Affected Entities by Category.

Category	NAICS code	Example of Potentially Affected Entities
Petroleum and Natural Gas Systems.	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.
	486210	Pipeline transportation of natural gas.

Table B-1 in Part B of this Supporting Statement presents the Agency's best estimate of the number of potential affected facilities by industry segment. This information was derived based on review of information reported to the GHGRP, the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Energy Information Administration (EIA), the National Emissions Inventory (NEI), Drilling Information Desktop (a subscription database of production wells), and other publically available information.

4(b) *<u>Information Requested</u>*

(i) *<u>Data items, including recordkeeping requirements</u>*. Part 1 will collect corporate and operator-level contact information as well as equipment counts for key equipment (number of wells, tanks, separators, compressors, and dehydrators) at each centralized production surface site and each well surface site owned or operated by that operator. This information is expected to be readily available to the operator and no additional measurement of recordkeeping requirements are imposed. Part 2 will collect detailed unit-specific information on emission sources at selected facilities as well as information on emission controls or management practices used to reduce emissions at the selected facilities. A majority of the information requested under Part 2 is expected to be available from company records and would not require additional measurements to be performed. However, respondents will be required to collect and report detailed counts of pneumatic devices and equipment leak components if this information is not already available in the company records. Additionally, respondents of facilities that have separators or otherwise discharge liquids at elevated pressure to atmospheric storage vessels will have to collect pressurized samples of liquid streams in order to perform a flash analyses if these analyses are not available using the methods prescribed. Except for these three data elements, all other information requested in the Part 2 questionnaire is to be completed based on existing company records. The survey will also request submission of the recent emission measurements, if available, to further characterize the emission sources. These data elements are only required when measurement data are already available; respondents are not required to perform direct emission measurements (except for flash gas analysis) as a result of this information collection.

(ii) *<u>Respondent activities</u>*. The activities a respondent will undertake to fulfill the requirements of the information collection are presented in Attachments 4A and 4B. These include: i) read instructions; ii) compile requested information on each affected source based on existing data; iii) if necessary, visit the facility to perform required equipment counts and collect tank feed samples (Part 2 only); iv) if necessary, have the feed samples analyzed for flashing potential and composition of flash gas according to methods prescribed in the information collection (Part 2 only), v) perform final review of the compiled information, and vi) submit information to the EPA through electronic survey instrument. For Part 1 only, respondents also have the option of hard-copy submission.

5. ***The Information Collected--Agency Activities, Collection Methodology, and Information Management***

5(a) Agency Activities

A list of activities that will be required of EPA is provided in Attachment 5. These include: i) develop electronic questionnaire/reporting form; ii) answer respondent questions; and iii) review and analyze responses.

5(b) Collection Methodology and Management

In collecting and analyzing the information associated with this ICR, the EPA will use personal computers, Microsoft Excel© based reporting forms, and the e-GGRT reporting system. The EPA will ensure the accuracy and completeness of the collected information by reviewing each submittal. The information collected pursuant to this ICR will be maintained in a computerized database on secure EPA servers. To better facilitate uniformity in the format of the reports that are received, and, thus, increase the ease of data review and analysis, standardized survey Excel spreadsheet reporting forms will be developed and distributed to respondents.

5(c) Small Entity Flexibility

The Part 1 survey is required for all operators of oil and gas production facilities and all respondents to the Part 1 survey will be subject to the same requirements. The Part 2 survey employs a sampling approach of facilities in each industry segment, and facilities selected to complete the Part 2 survey will be subject to the same requirements. However, the pressurized sample analysis is limited to liquid streams greater than 10 barrels per day (bpd). It is anticipated that small entities may be more likely to have lower flows and thereby more likely to be exempt from this sampling requirement. Additionally, the EPA expects that small entities will have fewer well site facilities (for Part 1) and fewer emission sources at each facility (for Parts 1 and 2) so its response burden will be minimized. In addition, the Agency has opted to use an electronic format for the questionnaire, which allows some automation in the form and response fields, to reduce the burden and improve the data accuracy from all respondents, including small entities. Because the information requested under Part 1 is limited, especially for small entities, we are allowing respondents to Part 1 the option to submit via hard-copy, which will eliminate the need to register the facility online prior to data submission. The survey will contain questions to determine the small entity status of a facility. These questions may help to identify, quantify, and minimize the burden on small entities during the rulemaking process.

5(d) *Collection Schedule*

The EPA anticipates issuing the 114 letters on or about November 15, 2016. These section 114 letters would require the owner/operator of an oil and gas facility to complete and submit the Part 1 survey within 60 days of receipt of the survey, and would require facilities to complete and submit the Part 2 survey with 180 days of receipt.

6. Estimating the Burden and Cost of the Collection

6(a) *Estimating Respondent Burden*

The one-time burden estimate for reporting and recordkeeping requirements are presented in Attachments 4A and 4B. These numbers were derived from estimates based on the time needed to collect and enter the information required for each of the different forms included in the Part 1 and Part 2 surveys and the proportion of facilities in each industry segment that is expected to complete each form. These estimates represent the one-time burden that will be incurred by the recipients. These estimates are based on 15,000 respondents for Part 1 and 4,175 expected respondents to Part 2. In reality, the actual number of respondents to Part 1 may be less due to incorrect contact information so that not all questionnaires mailed out will be deliverable.

6(b) *Estimating Respondent Costs*

Attachments 4A and 4B present estimated costs for the required recordkeeping and reporting activities. Labor rates were based on May 2015 raw labor rates for the Mining: Oil and Gas Extraction Sector (NAICS 211000), loaded using an overhead factor of 110%, consistent with other ICRs. The resulting loaded hourly rates are $176.95 for management personnel, $148.95 for engineering personnel, $65.10 for plant operator personnel, and $47.08 for clerical personnel. These values were taken from the Bureau of Labor Statistics Occupational Employment Statistics Survey Web site and reflect the latest values available (May 2015).

6(c) *Estimating Agency Burden and Cost*

The costs the Federal Government would incur are presented in Attachment 5. Labor rates and associated costs are based on the estimated 2015 loaded hourly rates (labor rate plus 60% for overhead) of $88.30 for management personnel (GS- 15, step 5); $53.42 for technical personnel (GS- 12, step 5); and $30.11 for clerical personnel (GS-7, step 5). These labor categories and burden estimates were selected to be consistent with other ICRs.

6(d) *Estimating the Respondent Universe and Total Burden and Costs*

The potential respondent universe consists of approximately 15,000 operators for Part 1 representing approximately 698,800 facilities (based on total well counts assuming 2 wells per facility). Thus, the burden estimate for each operator is based on reporting information for approximately 50 facilities on average, with 2 wells per facility. Furthermore, the Agency is estimating a 10 percent out of sample rate to determine the number of Part 2 questionnaires to be mailed out to ensure a statistically significant number of responses are received and expects a similar response rate for the Part 1 survey. As the Part 1 survey is designed as a frame census of all well operators, the respondent burden for Part 1 is conservatively estimated based on 15,000 respondents. Our assessment of the mailing address list is slightly less than 15,000 operators and therefore consistent with this estimate.

Part 2, designed as a statistically based sampling survey of each of the industry segments, is described in greater detail in Part B of this Supporting Statement. Table B-3 in Part B of this Supporting Statement provides the total facility counts in each industry segment, the number of responses needed, and the number of questionnaires to be mailed to ensure the desired number of responses are received. Thus, the Part 2 burden estimates are based on mailing out 4,656 Part 2 questionnaires and receiving 4,175 responses from industry respondents. Burden estimates were projected for each questionnaire form based on the number of sources expected to be at a typical facility when that source type is present. Additionally, not all source types will be present at certain types of facilities or at all facilities of a certain type. For example, well sites are only expected to be at production facilities and acid gas removal units may not be present at every production facility. Therefore, the fraction of facilities within a given industry segment that are expected to have a specific source type were also estimated in order to determine the number of respondents for each form. Table 2 summarizes the assumptions used to estimate the respondent burden for the Part 2 survey.

6(e) *Bottom Line Burden Hours and Costs Tables*

(i) *Respondent tally.* The total industry burden hours and costs, presented in Attachments 4A and 4B, are calculated by summing the person-hours column and by summing the cost column. The burden and cost to the industry is 284,751 hours and $42,453,050, which includes $6,557,400 in operation and maintenance (O&M) costs to cover postage and contracting services for storage vessel feed material flashing analyses.

Table 2. Assumptions used to Estimate Respondent Burden for Part 2.

Form/Sheet Name	Number of Units per Form Used to Estimate Time Needed to Complete Form	Fraction of Facilities with Source Type[1]							
		Prod	G&B Comp	G&B Pipe	Proc	TC	TP	UNGS	LNG
Facility (& Intro)	1	1	1	1	1	1	1	1	1
Production wells	2 wells	1	0	0	0	0	0	0	0
Inject/Store wells	2 wells	0.5	0	0	0	0	0	1	0
Tanks Separators	6 (2 separators; 4 tanks)	1	1	1	1	1	0	0	0
Pneumatic Devices	1 (multiple devices)	0.8	0.5	0.5	0.5	0.5	0.5	0	0
AGRU	1	0.5	0.5	0.2	0.5	0	0	0	0
Dehydrators	1	0.5	0.5	0.2	1	0.2	0	0.2	0.2
Compressors	4	0.5	1	0	0.5	1	0	1	1
Equipment Leaks	1 (multiple components)	1	1	1	1	1	1	1	1
Blowdown Events	1 (multiple events)	1	1	1	1	1	1	1	1
Control Devices	2 (1 flare and one vapor recovery unit)	1	1	0.5	1	0.5	0	0.5	0.5
Equip.Component Counts	multiple components[2]	1	1	2	2	1	2	1	1
Feed Samples	2	1	0.25	0.25	0.5	0.25	0	0	0

[1]Abbreviations for industry segments are as follows: Prod – production; G&B – gathering and boosting; Comp – compression; Pipe - pipeline; Proc – processing; TC – transmission compression; TP – transmission pipeline; UNGS – underground natural gas storage; LNG – LNG storage as well as LNG import and export.

[2]Burden associated with performing counts of equipment components for gas processing and pipeline facilities were expected to be twice that of other types of oil and gas facilities.

The reporting and recordkeeping burden and cost to production operators for the Part 1 information collection is 126,788 hours and $17,931,231, which includes $15,000 in O&M costs to mail the hard copies of the responses (see Attachment 4B). The reporting and recordkeeping burden and cost to the industry for the Part 2 information collection for facilities selected for the detailed Part 2 survey is 157,963 hours and $24,521,818, which includes $6,542,400 in O&M costs for contracted storage vessel feed material flashing analyses (see Attachment 4B).

(ii) <u>*Agency tally.*</u> The total line Agency burden and cost, presented in Attachment 5 is calculated in the same manner as the industry burden and cost. The estimated burden and cost are 14,843 hours and $801,740, which includes $107,204 in O&M costs to send certified section 114 letters to all respondents selected for Part 1 and Part 2 surveys with electronic return receipt.

(iii) <u>*The complex collection.*</u> The fraction of facilities within a given industry segment that are expected to have a specific source type were estimated in order to determine the number of respondents for each form. Table 2 summarizes the assumptions used to estimate the respondent burden for the Part 2 survey.

(iv) <u>*Variations in the annual bottom line.*</u> This section does not apply as this is a one time collection.

6(f) <u>*Reasons for Change in Burden*</u>

This is the initial estimation of burden for this information collection; therefore, this section does not apply.

6(g) <u>*Burden Statement*</u>

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose, or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

The total reporting and recordkeeping burden and cost to production operators for the Part 1 information collection is 126,788 hours and $17,931,231 (8.45 hours and $1,195 per respondent for 15,000 respondents). The total annual reporting and recordkeeping burden and cost to the industry for the Part 2 information collection is 157,963 hours and $24,521,818 (37.84 hours and $5,873 per respondent for 4,175 respondents).

This ICR does not include any requirements that would cause the respondents to incur either capital or start-up costs. The EPA has assumed that all respondents will contract (i.e., purchase services/operation and maintenance costs) for the storage vessel feed material flashing analyses. In addition, there will be a small O&M costs for respondents electing to mail a hard copy of the Part 1 responses. These costs have been included in the burden estimate above. The resulting total burden for Part 1 and Part 2 of this information collection is 284,751 hours and $42,453,050, which includes $6,557,400 in O&M costs to cover mailing hard copies of Part 1 responses and contracting services for storage vessel feed material flashing analyses.

PART B OF THE SUPPORTING STATEMENT

INFORMATION COLLECTION EFFORT FOR OIL AND GAS FACILITIES

1. Respondent Universe

This ICR will collect information from oil and gas industry sectors including facilities associated with production, processing, transmission, and storage of oil and natural gas. This ICR is specific to onshore operations and does not include offshore oil and gas production facilities. This ICR also does not include facilities located after the local distribution company (LDC) custody transfer station. Thus, this ICR covers the following industry segments within the oil and gas industry: onshore petroleum and natural gas production; onshore petroleum and natural gas gathering and boosting; onshore natural gas processing; onshore natural gas transmission compression; onshore natural gas transmission pipelines; underground natural gas storage; LNG storage; and LNG import and export equipment.

Part 1 is a frame census of all operators of onshore petroleum and natural gas production facilities. The frame for Part 1 is a list of operators from Drillinginfo, which is a subscription data set collected for individual state permits. The Drillinginfo records generally represent operations in 2014. While Drillinginfo contains records for just under 1.4-million wells, there are approximately 385,500 wells that do not contain any operator information. An additional 187,000 wells have an operator name but no address information. Consequently, the frame for the Part 1 survey may only cover 60 percent of producing wells.

Part 2 is a survey to collect detailed information about individual facilities within each of the industry segment. The Part 2 survey design considers stratifying the Study Universe into strata based on the facility type (i.e., industry segment). Within each stratum, different sampling schemes and sampling intensities may be required to capture and adequately represent special features of the stratum considering the available frame for each stratum as described in the following paragraphs.

For onshore petroleum and natural gas production facilities, the frame is a list of US Well IDs from Drillinginfo that can be grouped based on production rates and gas-to-oil ratio and that have operator contact information. As previously discussed, approximately 40 percent of the well records in Drillinginfo do not contain operator address information. It is possible that these are older wells within the dataset (prior to States requiring this additional information) or simply incomplete information submitted for a given well. The EPA did provide an opportunity for facilities to update or add their contact information. Revisions to the contact information for the onshore petroleum and natural gas production industry segments were limited to approximately 1 percent of the records. It is expected that these revisions were made primarily by larger companies, which may bias the frame towards these larger operators. However, as only 1 percent of the records were revised, this potential bias is expected to be very limited.

For onshore petroleum and natural gas gathering and boosting industry segment, there are very limited data to frame this industry segment. The majority of gathering and boosting facilities also own either production facilities or natural gas processing facilities. Consequently, the frame for gathering and boosting facilities is a list of parent companies of production facilities and gas processing facilities from the GHGRP, supplemented with parent companies of gathering pipelines that were reported to PHMSA. A special form, the Gathering and Booting Random Facility Selector Tool, will be completed by the gathering and boosting parent companies in order to select specific facilities required to complete the Part 2 survey. While the frame may be biased toward larger companies (e.g., meeting emission thresholds required to report to the GHGRP, and larger companies more likely to have updated the mailing list information), the selection tool is expected to over-sample small gathering boosting companies. While the selector tool's target sampling rate is 9 percent, it rounds the number of facilities selected to the next highest whole number. Thus, a small company with only three gathering and boosting compression facilities will have one facility selected for Part 2 (a 33 percent sampling rate), while larger companies with 100 gathering and boosting compression facilities will have 9 facilities selected. It is unclear what the combined impacts of these two biases will be, but these two biases will tend to offset each other.

The frame for onshore natural gas compression transmission is individual transmission compressor stations; the list of these compressor stations was compiled from the GHGRP, 2014 National Emissions Inventory (NEI), and Midwest Publishing data. The frame for natural gas transmission pipeline "facilities" are state-level pipeline companies compiled from PHMSA data. The frame for underground natural gas storage facilities is a list of underground storage facilities reported to the GHGRP supplemented with Midwest Publishing data and Drillinginfo data on operators of natural gas injection wells. The frame for LNG storage and LNG import and export facilities from the GHGRP supplemented with facilities identified via internet searches. The available information to frame these industry segments was much more complete and these frames are expected to provide an accurate and unbiased representation of each of these other industry segments.

2. Respondent Universe Stratification

As noted previously, there are numerous types of oil and gas facilities, which are referred to as industry segments. To ensure a representative sample of facilities across industry segments, oil and gas facilities were initially stratified by industry segment (Facility type) as noted in Table B-1. Table B-1 provides a listing of the oil and gas facility industry segments that this ICR will examine and the number of facilities and parent companies expected to be included in each industry segment.

Table B-1. Facility Count for Oil and Gas Industry by Industry Type

Facility Type	Count of Parent Companies	Count of Facilities	Source of Counts[1]
Onshore petroleum and natural gas production facility	15,000	698,800	DI Desktop
Onshore petroleum and natural gas gathering and boosting compression facility	800	5,000	GHGRP, PHMSA
Onshore petroleum and natural gas gathering and boosting pipeline facility	800	5,000	Assumed similar to compression
Onshore natural gas processing plant (or facility)	620	668	EIA
Onshore natural gas transmission compressor station	NA	1,400	EIA
Natural gas transmission pipeline facility	646	939	PHMSA
Underground natural gas storage facility	NA	418	EIA
Liquefied natural gas (LNG) storage facility	70	100	PHMSA
LNG import and export facility	11	11	PHMSA

[1]Sources of counts are as follows:
DI Desktop = Drilling Information Desktop, a subscription database of production wells; Facility count assumes 2 wells per facility.
GHRP- developed from GHGRP corporate entities in gas processing and gas production, supplemented with PHMSA dataset.
PHMSA = Pipeline and Hazardous Materials Safety Administration
EIA = Energy Information Administration

Since each industry segment is considered to have unique characteristics, each industry segment is considered to be a different population or stratum for statistical sampling purposes. The Agency also considers that the representation of the production segment should be further stratified, for the purpose of this ICR, based on differences in the type of well (oil or natural gas, production rates and gas-to-oil ratio), the type of formation, and the production basin. The Agency proposed two options for establishing different subpopulations or sub-strata within the production segment stratum: one based on the well type using GOR ranges and one based on regional groupings of basins. After a review of the comments received, we are proceeding with the GOR groupings, but we are adding a sub-strata for "stripper wells," which are wells that produce 15 barrels of oil equivalence (BOE) per day or less. Commenters indicated that these wells generally make up about 80 percent of the total number of wells but only contribute about 10 percent of the crude oil and natural gas produced in the United States.[1,2] Table B-2 provides a summary of the sub-strata to be considered in the production segment stratum.

Table B-2. Populations Considered within the Onshore Petroleum and Natural Gas Production Industry Segment

Production Facility Type	Count of Wells	Estimated Count of Facilities[1]
Nonstripper Heavy Oil Well, GOR ≤ 300 scf/bbl	25,832	12,916
Nonstripper Light Oil Well, 300 < GOR ≤ 100,000 scf/bbl	124,456	62,228
Nonstripper Wet Gas Well, 100,000 < GOR ≤ 1,000,000 scf/bbl	29,491	14,746
Nonstripper Dry Gas Well, GOR > 1,000,000 scf/bbl	51,398	25,699
Nonstripper Coal Bed Methane Well	10,719	5,360
Stripper Heavy Oil Well, GOR ≤ 300 scf/bbl	477,305	238,653
Stripper Light Oil Well, 300 < GOR ≤ 100,000 scf/bbl	307,042	153,521
Stripper Wet Gas Well, 100,000 < GOR ≤ 1,000,000 scf/bbl	32,689	16,345
Stripper Dry Gas Well, GOR > 1,000,000 scf/bbl	303,383	151,692
Stripper Coal Bed Methane Well	35,113	17,557
TOTALS	1,397,428	698,717

[1]Facility count is based on number of wells assuming 2 wells per facility, based on NSPS OOOOa Technical Support Document, Docket Item EPA-HQ-OAR-2010-0505-5120.

Because of the differences in the number of facilities in each stratum or sub-strata, each responding facility will be assigned weights based on the number of facilities in that stratum of substrata. The basic equation for response weighting is:

$$WtF_i = N_i/R_i$$

where,

[1] U.S. Energy Information Administration. "Stripper wells accounted for 10% of U.S. oil production in 2015," June 29, 2016. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=26872.

[2] U.S. Energy Information Administration. "Stripper wells accounted for 11% of U.S. natural gas production in 2015," July 28, 2016. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=27272.

WtF_i = weighting factor for stratum or sub-strata "i".

N_i = the total number of facilities within the stratum or sub-strata "i".

R_i = the total number of facilities for which survey responses were received within the stratum or sub-strata "i".

For example, if 400 facility responses are received for nonstripper heavy oil wells, then the weighting factor for nonstripper heavy oil wells will be 12,916/400 = 32.29.

3. Sample Size

As discussed earlier, Part 1 is a frame census of all production operators for which address information is available. Part 1 is designed to obtain general information about each well surface site and each well site facility to understand the overall industry segment and range of operations. Therefore, the sample size for Part 1 is the entire universe of operators for which address information is available. Part 2 is a representative sample of all facilities in the oil and gas sector and detailed information will be requested for operations within the selected facilities. To obtain a representative sample, the study universe will be stratified in industry segments, and a random sample of facilities will be selected from each stratum or sub-stratum using systematic selection proportional to the number of facilities in each geographical area or basin. With this type of selection, we ensure that we obtain in the sample facilities with representative geographical coverage.

A key consideration in survey design is determining how large a sample is needed for the estimates obtained from that sample to be statistically reliable enough to meet the objectives of the study within a specified confidence interval. In general, the estimates are considered statistically reliable if they meet the criteria for desired levels of accuracy and precision. Accordingly, while determining sample sizes for the facility populations shown in Tables B-1 and B-2, we considered desired levels of accuracy and precision for the estimates to be obtained from survey sampling.

The type of outcome (continuous, proportion or categorical), the desired margin of error, and the specified confidence level are the key factors for determining sample sizes to ensure that estimates have desired levels of accuracy. In general, two types of outcomes are considered in the survey: binary outcomes (derived from yes/no questions, for which a proportion of respondents may be estimated) and continuous outcomes (e.g., average (mean) value may be estimated). The necessary sample size when there is an infinite population size (n_o) may be determined as follows:

$$n\_o = p \times (1-p) \times (z/error)^2 \quad \text{when the objective is estimation of a proportion}$$

$$n\_o = (t \times s/error)^2 \quad \text{when the objective is estimation of a mean}$$

where,

- *p* = expected proportion of a given outcome, typically assumed to be 0.5 as this maximizes the variance. $p \times (1-p)$.
- *z* = z-statistic based on desired confidence level.
- *error* = acceptable margin of error or desired precision.
- *t* = t-statistic based on desired confidence level and expected population size. Same as z-statistic for population sizes greater than 30.
- *s* = the standard deviation of the estimate of the outcome.

For binary outcomes (estimation of a proportion), the Agency has selected a 95 percent 2-sided confidence level ($z = 1.96$) and a 5 percent margin of error ($error = 0.05$). The Agency considers these selections adequate to assure the objectives of the ICR will be met for outcomes for the key populations (i.e., the non-stripper well GOR populations and all other non-production populations). Therefore, the projected sample size needed for binary outcomes for the key populations is 385 [i.e., $(0.5 \times 0.5 \times (1.96/0.05)^2 = 384.16$, which would round up to 385]. For the stripper well populations, the Agency considers a 10 percent margin of error ($error = 0.10$) to be acceptable. Therefore, the projected sample size needed for binary outcomes for the stripper well populations is 97 [i.e., $(0.5 \times 0.5 \times (1.96/0.10)^2 = 96.04$, which would round up to 97].

For continuous outcomes designed to estimate a mean value, the Agency's acceptable margin of error is dependent on the variability of the data. For certain emission sources, like equipment leaks or compressor emissions, emission values often vary over 4 to 5 orders of magnitude. With these highly variable emission sources, we have found that the relative standard deviation (standard deviation divided by the mean, s/μ where μ is the mean) is generally 3. For example, the average relative standard deviation for compressor emissions data from the Greenhouse Gas Reporting Program (GHGRP) is 2.76[3]. For sources with such large variability (i.e., $\sigma/\mu \sim 3$), we consider it reasonable to know the mean value within ±30% (i.e., $error/\mu = 0.3$ or $error = 0.3\mu$). For data that are less variable (i.e., data that only vary over one or two orders

[3] Based on the data in Table 6-4 of the Greenhouse Gas Reporting Rule: Technical Support for 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule, Docket Item No. EPA-HQ-OAR-2011-0512-0100

of magnitude), the relative standard deviation is typically 1 or less (i.e., $\sigma/\mu \le 1$). For these less variable data, we consider it reasonable to know the mean value within ±10%. For both types of sources (i.e., those with more variable data and those with less variable data) we find that s/*error* = 10 provides a reasonable level of accuracy for the key populations (e.g., when s = 3µ and *error* = 0.3µ, then s/ *error* = 3µ/(0.3µ) = 10). Using s/*error* = 10 and the *t* value of 1.96 (based on a 95 percent 2-sided confidence level with population size greater than 30), the projected sample size needed for numeric value questions is 385 [i.e., $(1.96\times10)^2 = 384.16$, which would round up to 385]. For the stripper well populations, the Agency considers it reasonable to accept higher errors, such that the acceptable ratio of s/*error* = 5. Therefore, the projected sample size needed for numeric value questions is 97 [i.e., $(1.96\times5)^2 = 96.04$, which would round up to 97].

Data precision can be characterized as the ability to distinguish the difference between two estimates obtained from a sample, which is termed the power of a conclusion in statistical terms. The sample size needed to assess differences between means is given by the following formula.

$$n\_o = [(Z_{1-\alpha/2}+Z_{1-\beta}) / ES]^2 \qquad \text{when the objective is estimation of a mean}$$

where,

$Z_{1-\alpha/2}$ = z-statistic based on desired 2-sided confidence level; typically a value of $Z_{1-\alpha/2} = 1.96$ for the 95 percent confidence interval is used in power analyses.

$Z_{1-\beta}$ = z-statistic based on desired 1-sided power level; $Z_{1-\beta} = 1.282$ for 90 percent power.

ES = the effect size = $|\mu_1 - \mu_2|/\sigma$.

For proportional sampling, the sample size equation is the same, but the effect size, ES, is defined as $ES = |p_1 - p_2| / (p\times(1-p))^{0.5}$.

The effect size (ES) can be obtained from available studies (e.g., available studies from which the standard deviation may deduced), expert opinion, or it can be selected based on recommended values. In the absence of more-specific prior information, it is common practice to use an effect size value of 0.5 when interested in discerning a moderate to large effect, and an effect size of 0.2 if interested in discerning a small effect.[4] Since no prior information on the standard deviation for most of the values requested in the information collection, we considered using the recommended value of 0.2 to discern a small effect on an average value for the key populations. For binary outcomes, we considered it reasonable that a difference of 10 percent (p_1 -

[4] http://meera.snre.umich.edu/power-analysis-statistical-significance-effect-size

$p_2 = 0.1$) be discernable. The maximum value of the denominator, $(p\times(1\text{-}p))^{0.5}$, is 0.5 (when p = 0.5). Therefore, for binary outcomes, we determined that an ES value of 0.2 (0.1/0.5=0.2) is appropriate. Thus, we concluded that, regardless of the type of question, effect size of 0.2 is sufficient for the purposes of this information collection effort. Using an effect size of 0.2 for a small effect, 90 percent power ($Z_{1\text{-}\beta} = 1.282$), and a 95 percent confidence interval, the required sampling size is 263 (, i.e., $[(1.96+1.282)/0.2]^2= 262.76$).

Therefore, for any question included in the information collection request, we determined that the target sample size (for infinite population sizes) for the key populations is 385. We also determined that this sample size is sufficient for the needs of this information collection request in terms of our desired requirements of accuracy (error margin) and precision (effect size) for these populations.

For the stripper well populations, we initially considered using the recommended value of 0.5 to discern a moderate effect on an average value. For proportional questions, we consider it reasonable that a difference of 20 percent (p_1 - p_2 = 0.2) be discernable. The maximum value of the denominator, $(p\times(1\text{-}p))^{0.5}$, is 0.5 (when p = 0.5). Therefore, for proportional questions, we determined that an ES value of 0.4 (0.2/0.5=0.4) is appropriate. Consequently, we determined that, regardless of the type of question, an effect size of 0.4 is sufficient for the purposes of this information collection effort to discern a moderate effect for the stripper well populations. Using an effect size of 0.4 for a moderate effect, 90 percent power ($Z_{1\text{-}\beta} = 1.282$), and a 95 percent confidence interval, the required sampling size is 66 (, i.e., $[(1.96+1.282)/0.2]^2= 65.69$).

Therefore, for any question included in the information collection request, we determined that the target sample size (for infinite population sizes) for the stripper well populations is 97. We also determined that this sample size is sufficient for the needs of this information collection request in terms of our desired requirements of accuracy (error margin) and precision (effect size) for these populations.

For finite populations of size N, the actual sample size (n) needed to meet the ICR survey objectives is given by the following equation:

$$n = n\_o/(1+n\_o/N)$$

When applying this equation, we used the theoretical value of *n_o* of 384.16 for the key populations and 96.04 for the stripper well populations to calculate *n* and then rounded the calculated value of *n* up to the next highest integer. Table B-3 provides the results of this calculation based on the size for each of the facility type populations to be considered.

The Agency also estimates that facility out of sample rate will be approximately 10 percent due to inaccurate contact information and facility closures. Therefore, the Agency also projected the number of detailed survey form requests that would have to be mailed out based this 10 percent out of sample rate. These results were rounded up to the next integer and are also provided in Table B-3. For populations with a large number of facilities, like the non-stripper light oil production segment population, 425 facilities (382/0.9) will be selected to receive the survey. For the LNG storage and the LNG import and export segments, there are a limited number of facilities, so a complete survey rather than sampling from the population will be employed.

Table B-3. Desired Survey Sample Size and Number of Requests Sent by Industry Segment

Production Facility Type	Estimated Count of Facilities	Target Number of Responses	Number of Requests to be Sent[1]
Subpopulation for Onshore petroleum and natural gas production			
Nonstripper Heavy Oil Well, GOR ≤ 300 scf/bbl	12,916	374	416
Nonstripper Light Oil Well, 300 < GOR ≤ 100,000 scf/bbl	62,228	382	425
Nonstripper Wet Gas Well, 100,000 < GOR ≤ 1,000,000 scf/bbl	14,746	375	417
Nonstripper Dry Gas Well, GOR > 1,000,000 scf/bbl	25,699	379	422
Nonstripper Coal Bed Methane Well	5,360	359	399
Stripper Heavy Oil Well, GOR ≤ 300 scf/bbl	238,653	97	108
Stripper Light Oil Well, 300 < GOR ≤ 100,000 scf/bbl	153,521	96	107
Stripper Wet Gas Well, 100,000 < GOR ≤ 1,000,000 scf/bbl	16,345	96	107
Stripper Dry Gas Well, GOR > 1,000,000 scf/bbl	151,692	96	107
Stripper Coal Bed Methane Well	17,557	96	107
Subtotal for Onshore petroleum and natural gas production facility	698,717	2,350	2,615
Onshore petroleum and natural gas gathering and boosting compression facility	5,000	357	397
Onshore petroleum and natural gas gathering and boosting pipeline facility	5,000	357	397

Onshore natural gas processing plant (or facility)	668	244	272
Onshore natural gas transmission compressor station	1,400	302	336
Natural gas transmission pipeline facility	939	273	304
Underground natural gas storage facility	418	201	224
Liquefied natural gas (LNG) storage facility	100	80	100
LNG import and export facility	11	11	11
TOTALS	712,253	4,175	4,656

[1]Number of requests sent calculated as Target Number of Responses×(1+OOS/(1-OSS)), where OOS is the out of sample rate, which is assumed to be 0.1. If this number is close to or exceeds the total number of facilities in a stratum, the number of requests sent is equal to the facility count.

To ensure that random sampling of facilities within the production segment includes a proportional number of facilities within a given basin, a proportional allocation of wells will be used within each production population. In proportional allocation, the number of wells selected from a given subcategory (e.g., the number of wells selected from a specific basin within a GOR population), n_h is determined as follows:

$$n_h = n_{requests} \times (N_h/N)$$

where,

n_h = the number of wells of a specified type within a given production population to which requests will be sent.

$n_{requests}$ = the total number of wells for which requests will be sent within a given production population.

N_h = the total number of wells of a specified type within the population.

N = the total number of wells within the population.

In the proportional allocation, the values are rounded to the nearest integer, so that the sum of the all n_h equals (but does not exceed) $n_{requests}$. Thus, if a given basin accounts for 20 percent of the all stripper wet gas wells, where $n_{requests}$ = 107 (see Table B-3), then 21 stripper wet gas wells (107 × 0.20 = 21.4) will be randomly selected from that basin to receive the Part 2 survey.

For basins that have two or more wells to be selected for a given sub-strata, we will also review the operators of the wells to perform further proportional assignments based on the operators in that basin to ensure wells selected within the basin represent the different operators in that basin.

The random selection process will use Excel's random number generator, which provides values from 0 to 1. If one well is to be selected from a sub-strata, then all wells in that sub-strata will be assigned a random number and the well with the lowest random number will be selected for the Part 2 survey. Similarly, if 2 wells are to be selected from a sub strata, the two wells with the lowest random numbers will be selected for the Part 2 survey, and so on for 3 or more wells to be selected from a sub strata.

4. Respondent Sample Collection

A random selection process will be used as described above to determine the well ID numbers selected for the Part 2 survey. The facility that contains a well selected for the Part 2 survey must complete the Part 2 survey for every well at that facility. There may be cases where two selected wells will be located at a single facility. The Agency considers this unlikely given the small fraction of production wells that will be selected compared to the total population of wells within each population. Additionally, the out of sample rate factor used to estimate the number of wells selected is expected to help ensure that the targeted number of facility responses will be received even if some facilities contain multiple wells selected for the Part 2 survey.

5. Response Rates

Since the information will be requested pursuant to the authority of section 114 of the Act, EPA anticipates that all respondents that receive the questionnaire will submit information will do so. However, for most of the industry segments, we are unsure if the facility contact information we do have is accurate. While we are confident that we have good contact information for current GHGRP reporters, we are interested in obtaining information for a significant number of reporters that do not currently report to the GHGRP. Given the uncertainty in the accuracies of the contact information, we have estimated a 10 percent out of sample rate for each industry segment.

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Attachment 4A:	Industry Burden and Cost for Responding to the Part 1 Questionnaire
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Attachment 5:	Agency Burden and Cost

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
1	U.S. States	Alabama; Alaska; Arizona; Arkansas; California; Colorado; Connecticut; Delaware; Florida; Georgia; Hawaii; Idaho; Illinois; Indiana; Iowa; Kansas; Kentucky; Louisiana; Maine; Maryland; Massachusetts; Michigan; Minnesota; Mississippi; Missouri; Montana; Nebraska; Nevada; New Hampshire; New Jersey; New Mexico; New York; North Carolina; North Dakota; Ohio; Oklahoma; Oregon; Pennsylvania; Rhode Island; South Carolina; South Dakota; Tennessee; Texas; Utah; Vermont; Virginia; Washington; West Virginia; Wisconsin; Wyoming
2	Yes/No	Yes; No
3	Facility Type	Onshore petroleum and natural gas production; Onshore petroleum and natural gas gathering and boosting; Onshore natural gas processing; Onshore natural gas transmission compression; Both onshore natural gas transmission compression and underground natural gas storage; Onshore natural gas transmission pipeline; Underground natural gas storage; Liquefied natural gas (LNG) storage; LNG import and export equipment; Other
4	Number of Months	12; 11; 10; 9; 8 ;7; 6; 5; 4; 3; 2; 1; 0
5	Frequency Site Visited	2 or more times per week; Weekly; Monthly; Quarterly; Less frequently than quarterly
6	Land Ownership	Owned; Government leased; Private leased; Tribal
7	Management of Produced Waters	Open pits/surface impoundments; Open storage tanks; Fixed roof tanks vented to atmosphere; Fixed roof tanks vented to control/recovery; Floating roof tanks; Off well site tank battery
8	Basin ID	*List of oil and gas basins, consistent with GHGRP*
9	County and State in which the sub-basin is located	*List populates the county and state depending on the basin ID selection consistent with the GHGRP*
10	Well Drilling Type	Vertical;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Directional; Horizontal
11	Sub-basin Formation Type	Oil; High permeability gas; Shale Gas; Coal Seam; Other tight reservoir rock
12	Well Type	Producing heavy oil stripper well Producing light oil stripper well Producing wet gas stripper well Producing dry gas stripper well Producing coal bed methane stripper well Producing heavy oil nonstripper well Producing light oil nonstripper well Producing wet gas nonstripper well Producing dry gas nonstripper well Producing coal bed methane nonstripper well Temporarily shut-in heavy oil stripper well Temporarily shut-in light oil stripper well Temporarily shut-in wet gas stripper well Temporarily shut-in dry gas stripper well Temporarily shut-in CBM stripper well Temporarily shut-in heavy oil nonstripper well Temporarily shut-in light oil nonstripper well Temporarily shut-in wet gas nonstripper well Temporarily shut-in dry gas nonstripper well Temporarily shut-in CBM nonstripper well Permanently plugged/abandoned production or storage well Natural gas storage well Active injection well Inactive/abandoned injection well
13	Flow monitoring	Flow monitor at well (prior to separator) Flow monitor of separator outlet Flow monitor at facility outlet (sales line) Off site
14	Disposition of casing head gas	Vented to atmosphere; Vented to flare; Routed to gas line, no additional compression; Routed to gas line via casing head gas compressor
15	Well Completion / Workover Type	With hydraulic fracturing; Without hydraulic fracturing
16	Controls (testing, well workovers)	Vent to flare/thermal oxidizer; Vent to other control; Capture for recovery/sales; Vent to atmosphere;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		No emissions occur during the event
17	Primary Liquids Unloading Technique	Shut in well to build-up pressure, then blowdown well; Plunger lift system; Plunger lift with smart automation; Automated (timed) plunger lift system; Swabbing the well; Use velocity tubing; Use other artificial lift system (e.g., rod pumps); Surfactants and foaming agents; Not applicable/oil well
18	Controls for venting for liquids unloading	Knock-out drum; gas sent to flare/ThOx; Knock-out drum; gas recovered for sale; Knock-out drum; gas recovered for use on site; Vent to uncontrolled separator/drum; Vented directly to the atmosphere; Closed-loop system, no venting
19	Vessel Type	Gas-liquid separator; Heater/treater; Ambient storage tank receiving liquids directly from well; Ambient storage tank receiving liquids directly from separator; Condensate storage tank, fixed roof; Condensate storage tank, floating roof; Other hydrocarbon storage tank, fixed roof; Other hydrocarbon storage tank, floating roof; Aqueous/water storage tank, open/uncovered; Aqueous/water storage tank, fixed roof; Aqueous/water storage tank, floating roof
20	Feed Type	Mixed oil/condensate, water and natural gas Mixed oil/condensate and water Mixed oil/condensate and natural gas Mixed water and natural gas Crude oil Natural gas liquids (condensate) Produced water Fracking fluids Other (specify)
21	Liquid Type used in gas liquid ratio	Oil/condensate; Water
22	Disposition of natural gas	Vent to flare/thermal oxidizer; Vent to other control; Capture for recovery/sales; Vented to atmosphere
23	Frequency	Monthly or more frequently; Quarterly; Semiannually;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Annually; Less than once per year
24	Thief Hatch Type	Gasketted, lockdown thief hatch; Ungasketted, lockdown thief hatch; Gasketted, spring-loaded thief hatch; Ungasketted, spring-loaded thief hatch; Gasketted, dead-weight thief hatch; Ungasketted, dead-weight thief hatch
25	Intermittent or continuous determination	Manufacturer's data sheet; Manufacturer's maximum gas consumption rate; Manufacturer's minimum gas consumption rate (device not actuating); Model number and supply pressure; Actual gas consumption rate of controllers over time; Measured gas supply rate; Measured venting rates; Other design considerations
26	Identifying malfunctioning controllers	Monitor NG consumption for all controllers and inspect controllers if consumption increases; Routine visual inspections of controllers; Routine visual inspections and monitoring NG consumption; Periodic inspections using optical imaging camera of vented emissions; Optical imaging camera, audio/visual; Audio/visual; Other (describe); None
27	Valve Actuator Type	Rotary vane isolation valve actuator; Turbine operated isolation valve actuator; Other
28	Pneumatic Device Type	Snap acting, intermittent bleed controller; Throttling low continuous bleed controller; Throttling high continuous bleed controller; Throttling intermittent bleed controller; Throttling no-bleed controller; Rotary vane isolation valve actuator; Turbine operated isolation valve actuator; Chemical injection piston pump; Chemical injection diaphragm pump; Liquid Circulation (Kimray) pump; Other
29	Equipment Leak Measurement Method	Calibrated bagging; High volume sampler; Temporary meter
30	AGRU Type	Diethanolamine (DEA) absorber

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Monoethanolamine (MEA) absorber Methyl diethanolamine (MDEA) absorber Other amine absorber (specify) Selexol process Rectisol process Membrane separator Molecular sieve Other (specify)
31	AGR Purpose	Removal of H2S and other sulfur compounds; Removal of CO2; Co-removal of H2S and CO2; Other (specify)
32	Disposition of Removed H2S / CO2	Vented to atmosphere Discharged to flare Used as fuel supplement (in engine) Recovered onsite - Claus unit Recovered onsite - other sulfur recovery unit Recovered offsite Recovered for sales or use in EOR Other (specify)
33	Dehydrator Type	Ethylene glycol Triethylene glycol Other glycol Mol Sieve Calcium chloride desiccant Lithium chloride desiccant Other desiccant Other (specify)
34	Recovered Methane Disposition	Used as fuel; Recycled to glycol absorber feed; Recovered to dry sales gas; Other (specify)
35	Glycol Reboiler Fuel	Wet (inlet) natural gas; Recovered flash tank separator gas; Dry (sales) natural gas; Other (specify)
36	Reboiler / Regenerator Exhaust Disposition	Vented to atmosphere Vented to flare or thermal oxidizer Vented to condenser Vented to condenser followed by flare or ThOx Other (specify)
37	Emission Reduction Work Practices	Optimize glycol circulation rates; Route reboiler condenser gas to fuel combustion units; Other (specify)
38	Monitoring	Optical gas imaging;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
	Method	Hi-flow sampler; EPA Method 21; Optical gas imaging and Hi-flow sampler; Optical gas imaging and EPA Method 21; Hi-flow sampler and EPA Method 21; Optical gas imaging, Hi-flow sampler, and EPA Method 21; Other (specify)
39	Leak Definition	500 ppmv; 1,000 ppmv; 2,000 ppmv; 5,000 ppmv; 10,000 ppmv; Any visible emissions using OGI; Other (specify)
40	Service Type	Gas Service; Light Crude Service; Heavy Crude Service
41	Equipment Type	Wellhead; Separator; Meters/piping runs; Compressors; In-line heaters; Dehydrators; Tanks (other than heater-treaters); Heater-treater; Header
42	Component Type	Valve; Connector; Open-ended line; Pressure-relief valve; Pump; Flange; Other
43	Comp Measurement Method	Calibrated bagging; High volume sampler; Temporary meter; Acoustic leak detection
44	Compressor Type	Wet seal centrifugal compressor; Dry seal centrifugal compressor; Reciprocating compressor; Rotary screw compressor; Rotary vane compressor; Scroll compressor; Diaphragm compressor; Other (specify)

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
45	Engine Type	Gas Turbine; Compression Ignition (diesel); Spark Ignition - 2-Stroke, Lean Burn; Spark Ignition - 4-Stroke, Lean Burn; Spark Ignition - 4-Stroke, Rich Burn; Electric
46	Fuel Type	Distillate Oil (Diesel); Natural Gas; NGL or Liquified Petroleum Gas (LPG); Electricity; Gasoline
47	Emissions Tier	1; 2; 3; 4
48	Control Types	Flare/Thermal Oxidizer; Gas recovered for sale; Gas recovered for use in stationary combustion device; Closed vent system
49	Operating Mode	Operating-mode; Standby-pressurized-mode; Not-operating-depressurized-mode
50	Measurement Type	As found; Continuous
51	Measurement Location	Prior to commingling; After commingling; Not manifolded
52	Frequency of rod packing replacement	Never; Semi-Annually; Annually; Biennially; Less Frequent than Biennially; Every 26,000 hours; Every 36 months; Either 26,000 hrs or 36 months (whichever is reached first); Based on leakage indicator; Other/Facility maintenance plan
53	Control Device Type	Unassisted candlestick flare Air-assisted candlestick flare Steam-assisted candlestick flare Enclosed flare/combustor Thermal oxidizer/incinerator Vapor recovery unit Condenser Carbon Adsorber - Canisters Carbon Adsorber - Regenerable Other (specify)
54	Ignition Source	Continuous pilot flame;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
	Type	Spark ignitor
55	Air Supply Fan Type	Single speed fan; Dual speed fan; Three speed fan; Variable speed fan
56	Number of Employees	750 or less; 751 to 1,250; 1,251 or more
57	NAICS code	211111 – Crude Petroleum and Natural Gas Extraction; 211112 – Natural Gas Liquid Extraction; 486210 – Pipeline transportation of natural gas; Other (specify)
58	Annual Receipts	$27.5-million or less; More than $27.5-million
59	Manned Facilities	24 hours per day Visited daily Visited weekly Visited monthly Visited quarterly Visited semi-annually Attended during venting only Not routinely visited
60	Type of Electricity	Power grid; Power grid with backup generator; Power grid with backup generator and solar/wind; Generator only; Generator and solar/wind only; Solar/wind only; Without power
61	Lack of Gathering Line	No permit for pipeline to tie to well system; Insufficient gas quantity/pressure; Poor gas quality/Does not meet specifications; No contract in place; Right-of-way acquisition; Transmission line approval; Transmission line construction; Exploration Well; Pipeline and/or plant capacity constraints
62	Mineral Rights Ownership	Private; Federal; Tribal
63	Combustion Equip Types	Open flare; Open pit flare; Enclosed flare; Thermal combustor;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Other
64	Type of Well Bore	Multilateral design; Capillary string
65	Injection/Storage Well Type	Active storage well; Active disposal well; Active EOR injection well; Temporarily shut-in injection/storage well; Permanently plugged injection/storage well
66	Injection/Storage Well Gas Type	Natural gas; Steam; CO2; Produced water/wastewater; Other, specify
67	Injection/Storage Well Reservoir Type	Salt cavern; Depleted natural gas or oil reservoir; Producing oil reservoir (e.g., EOR); Hard rock cavern; Aquifer; Other, specify
68	Thief Hatch Alarm	No alarms exist; A differential pressure monitor; Electrical contacts; Other
69	PRV Types	Conventional spring-loaded relief valve; Balanced bellows spring-loaded relief valve; Pilot-operated relief valve; Rupture disk; Relief valve and rupture disc in series; Relief valve and rupture disc in parallel; Other
70	Tanks Process Sim Software	TANKS 4.09D; E&P TANKS v3.0; ProMAX; Other (specify)
71	Pneumatic Emissions Minimization	Pumps connected to closed vent system (CVS); Pumps routed to control device; Air supplied to controllers; Solar/electric valves; Other
72	Dehy Process Sim Software	GRI-GLYCalc 4.0; ProMAX; Other (specify)
73		*(Reserved)*
74	Starter Engine	Electric Motor; Pneumatic (Gas) Motor;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Pneumatic (Air) Motor; Hydraulic Motor; Internal-Combustion Engine
75	Compressor Engine Operations	Transportation; Vapor Recovery; Refrigeration; Other (specify)
76	Tank Inspection	Audio, visual, olfactory, or instrument; Monthly or more frequently; Quarterly; Semiannually; Annually; Less than once per year
77	Flow Monitoring Oil Production	Flow monitor at facility outlet (sales line) Off site
78	Area/Major Source Dehy	Area; Major; Neither
79		*(Reserved)*
80	Dehy Throughput Range	< 3 MMscfd; 3 - 10 MMscfd; > 10 MMscfd
81	Dehy Benzene	Less than 1 ton per year of benzene; More than 1 ton per year of benzene
82	Dehy Urban Boundaries	Yes, located in an UA plus offset/UC boundary and DOES NOT meet flowrate or benzene emission exceptions; Yes, located in an UA plus offset/UC boundary and DOES meet flowrate or benzene emission exceptions; No
83	Well Production Economic	less than 1 year; 1 to 3 years; more than 3 years but less than or equal to 5 year; more than 5 years but less than or equal to 8 years; more than 8 years but less than or equal to 10 years; more than 10 years
84	Production Profile Type	Production curves for this well; Production curves for similar well at the well site; Production curves for similar well within basin; Other (specify)
85	NOx Control Type for Engines	Low-NOx Burner; Ultra-Low NOx Burner; Steam Injection; Water Injection; Selective Catalytic Reduction; Non-Selective Catalytic Reduction;

Attachment 1A: Oil and Gas ICR Survey Picklist Values

Picklist Number	Picklist Description	Picklist Values
		Ignition Retard; Natural Gas Reburn; Adjust Air to Fuel Ratio; Low Excess Air; Low Emissions Combustion; Other (specify); None
86	PM Control for Diesel	Diesel oxidation catalyst; Diesel particulate filters; Other (specify); None
87	Dehy Sat/SubSat	Saturated; Subsaturated
88	Dehy Glycol Pump Type	Electric; Pneumatic (Air); Pneumatic (Gas)
89	Blowdown Method	Calculated from directly determined volumes, pressures, and number of events Calculated based on estimated volumes/pressures and known number of events Estimated based on other available information

Attachment 1B: Oil and Gas ICR Survey Data Validation Rules

Data Validation Rule No.	Message Type	Data Validation Criteria	Data Validation Message
1	Error	Whole Number greater than or equal to 0	This input must be an integer greater than or equal to 0.
2	Error	Decimal greater than or equal to zero.	This input value must be a numeric value greater than or equal to 0.
3	Error	Whole Number between 1900 and 2016	Year must be between 1900 and 2016. If operations started prior to 1900, please enter 1900.
4	Error	Decimal between + or - 100,000,000	Restricted to values between + or - $100,000,000.
5	Error	Decimal between 0 and 200	This input is expected to have a numerical value between 0 and 200.
6	Error	Decimal between 0 and 300	This input is expected to have a numerical value between 0 and 300.
7	Error	Decimal between 0 and 2	This input is expected to have a numerical value between 0 and 2.
8	Error	Decimal between -0.000001 and 100	This input is expected to have a numerical value between 0.000001 and 100.
9	Error	Whole number between 0 and 8,784	This input must be an integer between 0 and 8,784.
10	Error	Whole number between 2000 and 2016	Year must be between 2000 and 2016.
11	Error	Decimal number between 0 and 1	This input value should be a fraction between 0 and 1.
12	Error	Whole number between 1900 and 2017	Expect Year Installed to be an integer between 1900 and 2017.
13	Error	Whole Number between 2016 and 2020	Year must be between 2016 and 2020.
14	Error	Date between 1/1/1900 and 12/31/2016	Date must be between 1/1/1900 and 12/31/2016. If operations started prior to 1900, please enter 1/1/1900.

Attachment 1B: Oil and Gas ICR Survey Data Validation Rules

Data Validation Rule No.	Message Type	Data Validation Criteria	Data Validation Message
15	Error	Decimal between 0 and 100.	Input must be between 0 and 100.
16	Error	Text length equal to 9.	You have entered an invalid number, please enter a number with 9 digits.
17	Error	Text length equal to 12.	You have entered the date format wrong. Please enter as 000-000-0000.
18	Error	Text length equal to 6.	You have entered an invalid number, please enter a GHGRP ID number with 6 digits.
19	Error	Whole number between 0 and 1000.	Input must be an integer equal to or greater than 0.
20	Error	Whole number between 0 and 100,000.	Input must be an integer between 0 and 100,000.

Attachment 2A: Part 1 Questionnaire and Instructions Sheet

Oil and Gas Information Collection Request: OMB Control No.

Part 1. Production Operator Survey

Instructions

This information collection request is designed to be completed by operators of onshore petroleum and natural gas (oil and gas) production facilities based on best available information; that is, information that is readily available. All information for each applicable surface site must be completed. Online mapping applications may be used to determine latitude/longitude coordinates for your surface sites.

Step 1. Please complete the parent company information requested under Section 1. This information should be for the highest-level, majority corporate owner.

Step 2. Please complete the operator information requested under Section 2. This information should be field operator sites managing one or more well sites. You should complete a separate worksheet for each separate field operator site.

Step 3. Please complete the information for each centralized production surface site (see definitions) requested under Section 3 for all centralized production surface sites managed by the operator that receive production fluids from a well surface site that must be listed in Section 4. You must include information for centralized production surface sites that may also be part of a well site facility required to complete Part 2 if the centralized production surface site also receives fluids from a well surface site that is not required to complete Part 2. There is a place to indicate that a centralized production surface site is also included in Part 2.

Step 4. Please complete the information requested for each well surface site (see definition) under Section 4 for all well surface site managed by the operator except those that contain a well for which the Part 2 - Detailed Facility Survey must be completed.

Please note that a well surface site generally refers to an individually permitted disturbed area of land associated with one or more wells and the equipment within that disturbed area of land. If multiple well surface sites and the associated production area all operate under a single permit, you may complete Section 4 considering the permitted facility to be a single well surface site.

Step 5. Please complete and sign the acknowledgement in the sheet Acknow tab and submit the completed form either electronically at:

https://oilandgasicr.rti.org/

or via hard copy to:

Attn: Ms. Brenda Shine
U.S. Environmental Protection Agency
109 T.W. Alexander Drive, Mail Code: E143-01
Research Triangle Park, NC 27709

Attachment 2A: Part 1 Questionnaire and Instructions Sheet

1.) Parent Company General Information

Legal Name:	
Does this company meet the definition of small business?	(Picklist #2)
Dun and Bradstreet Number:	
Parent Company Mailing Address:	
Parent Company Mailing City:	
Parent Company Mailing State:	(Picklist #1)
Parent Company Mailing Zip:	
Parent Company Contact Name:	
Parent Company Contact Title:	
Parent Company Contact Phone:	
Parent Company Contact Phone 2:	
Parent Company Contact Email:	
Parent Company Contact Email 2:	

2.) Operator General Office Information

Operator Name:	
Operator Office Physical Address:	
Operator Office Physical City:	
Operator Office Physical State:	(Picklist #1)
Operator Office Physical Zip:	
Operator Office Mailing Address:	
Operator Office Mailing City:	
Operator Office Mailing State:	(Picklist #1)
Operator Office Mailing Zip:	
Operator Office Contact Name:	
Operator Office Contact Title:	
Operator Office Contact Phone:	
Operator Office Contact Phone 2:	
Operator Office Contact Email:	
Operator Office Contact Email 2:	

3.) For each centralized production surface site (see definitions) under the control of the operator, receiving crude oil, condensate or natural gas direct from a well surface site, provide the following information.

Provide an ID, description and general information about each centralized production surface site:

Surface Site ID (Permit or lease ID number or other ID number, as applicable)	
Surface Site Name/Description	
Basin ID where Surface Site is Located	(Picklist #8)

County and State where Surface Site is Located	(Picklist #9)
Latitude of surface site (degrees decimal)	
Longitude of surface site (degrees decimal)	
Is this surface site subject to the fugitive emission requirements in 40 CFR 60.5397a of subpart OOOOa?	(Picklist #2)
Does this surface site produce natural gas for sales?	(Picklist #2)
Does this surface site produce crude oil or condensate for sales?	(Picklist #2)
Is there a flare or thermal combustor present at the surface site?	(Picklist #2)

Provide equipment counts for the major equipment listed below present at the centralized production surface site:

Number of Separators	(Data Validation #1)
Number of Atmospheric Storage Tanks <10 bbl/day	(Data Validation #1)
Number of Atmospheric Storage Tanks ≥10 bbl/day	(Data Validation #1)
Number of Dehydrators	(Data Validation #1)
Number of Reciprocating Compressors	(Data Validation #1)
Number of Dry Seal Centrifugal Compressors	(Data Validation #1)
Number of Wet Seal Centrifugal Compressors	(Data Validation #1)

4.) For each well surface site (see definitions) under the control of the operator, provide the following information.

Provide an ID, description and general information about each well surface site:

Surface Site ID (Permit or lease ID number or other ID number, as applicable)	
Surface Site Name/Description	
Basin ID where Surface Site is Located	(Picklist #8)
County and State where Surface Site is Located	(Picklist #9)
Latitude of surface site (degrees decimal)	
Longitude of surface site (degrees decimal)	
Is this surface site subject to the fugitive emission requirements in 40 CFR 60.5397a of subpart OOOOa?	(Picklist #2)
Does this surface site produce natural gas for sales?	(Picklist #2)
Does this surface site produce crude oil or condensate for sales?	(Picklist #2)
Is there a flare or thermal combustor present at the surface site?	(Picklist #2)

Provide equipment counts for the major equipment listed below present at the well surface site:

Number of Separators	(Data Validation #1)
Number of Atmospheric Storage Tanks <10 bbl/day	(Data Validation #1)
Number of Atmospheric Storage Tanks ≥10 bbl/day	(Data Validation #1)
Number of Dehydrators	(Data Validation #1)
Number of Reciprocating Compressors	(Data Validation #1)

Attachment 2A: Part 1 Questionnaire and Instructions Sheet

Number of Dry Seal Centrifugal Compressors	(Data Validation #1)
Number of Wet Seal Centrifugal Compressors	(Data Validation #1)

Provide the US Well ID Number (or other well ID number as provided to State or local permitting agency) for each well present at the surface site (include producing wells, temporarily shut-in, permanently plugged wells, storage wells, and injection wells); specify the well type (as of November 1, 2016) and other information requested for each well present at the surface site:

Well ID	
Well Type	(Picklist #12)
"Surface Site ID" of the centralized production surface site associated with the Well.	(Picklist = “Not applicable” plus list of Surface Site IDs from Table 3)

Attachment 2B: Part 1 Questionnaire Acknowledgement (Acknow) Sheet

Oil and Gas Information Collection Request

Part 1. Production Operator Survey

☐	I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete.

☐	I am authorized to make this submission on behalf of the owners and operators of the facility or facilities, as applicable, for which the submission is made.

____

Print Name

____ ____________________

Signature Date

Oil and Gas Information Collection Request

Part 1. Production Operator Survey

Term	Definition
Atmospheric storage tank	A class of storage tanks that store materials at approximately atmospheric pressure. Atmospheric storage tanks may store liquids at ambient temperatures or at elevated temperatures (e.g., heated demulsification tank).
Barrel	A common unit of measurement for the volume of crude oil produced or processed. The volume of a barrel is equivalent to 42 US gallons.
Barrel of oil equivalent (BOE)	A unit of energy equal to 5.8-million British thermal units (5.8 MMBtu) based on the approximate energy released be burning one barrel of crude oil. For the purposes of this information collection request, you may use 1 BOE = 1 barrel of crude oil produced and 1 BOE = 5,800 scf of natural gas produced rather than using a direct energy conversion.
Basin	Geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.
Centralized production surface site	Any onshore surface site that obtains crude oil or a mixture of crude oil and natural gas directly from multiple well surface sites without a custody transfer, and includes all equipment used in the transportation, compression, stabilization, separation, storing or treating of crude oil and/or natural gas (including condensate) located at the surface site.
Centrifugal compressor	Any machine for raising the pressure of a gaseous stream by drawing in low pressure gas and discharging significantly higher pressure gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this information collection request.
Compressor	Any machine for raising the pressure of a gaseous stream by drawing in low pressure gas and discharging significantly higher pressure gas.
Condensate	Hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.
Crude oil	A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending upon the characteristics of the crude stream, it may also include small amounts of non-hydrocarbons produced from oil, such as sulfur and various metals, drip gases, and liquid hydrocarbons produced from tar sands, gilsonite, and oil shale.
Dry gas well	For the purposes of this ICR, a well that produces natural gas, other than coal bed methane, with a GOR greater than 1,000,000 scf/bbl.
Equipment	The set of articles or physical resources used in an operation or activity.
Field operator site	A centralized office or company that serves as the overall manager of the

Attachment 2C: Part 1 Questionnaire Definitions Sheet

Term	Definition
	operations of one or more wells sites.
Flowback	The process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.
Gas-to-oil-ratio (GOR)	The ratio of the volume of natural gas that is produced or that comes out of solution when crude oil is extracted from a well and equilibrated to standard conditions to the volume of hydrocarbon liquids (crude oil and condensate) produced after the natural gas comes out of solution. This is often calculated by dividing the measured natural gas production by the measured crude oil and condensate production.
Heavy oil well	For the purposes of this ICR, a well that produces crude oil with a GOR of 300 scf/bbl or less.
Hydraulic fracturing	The process of directing pressurized fluids containing any combination of water or other base fluid, proppant, and any added chemicals to penetrate a formation, generally to stimulate production, that subsequently require flowback to expel fracture fluids and solids during completions.
Hydraulic refracturing	Conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.
Light oil well	For the purposes of this ICR, a well that produces crude oil with a GOR greater than 300 scf/bbl but less than or equal to 100,000 scf/bbl.
NAICS code	The numerical code of up to 6 digits used by the North American Industry Classification System (NAICS) for classifying business establishments by industry sector.
Natural gas	A naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.
Nonstripper well	A well that produces more than 15 barrels of oil equivalent (BOE) per day on average over a 12-month period.
Onshore	All facilities except those that are located in the territorial seas or on the outer continental shelf.
Onshore petroleum and natural gas production	The oil and gas industry segment responsible for the extraction and production of crude oil, condensate, and/or natural gas and generally operate under NAICS code 211111 or 211112.
Owner or operator	Any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.
Plugged well	A well that has been sealed, typically by filling a portion of the well bore with cement, in order to permanently abandon the well following State, local or

Attachment 2C: Part 1 Questionnaire Definitions Sheet

Term	Definition
	other regulatory body requirements for plugging and abandoning the well.
Producing well	A well for which crude oil or natural gas are actively flowing from a subsurface reservoir and through the wellhead valve.
Reciprocating compressor	A piece of equipment that increases the pressure of a gaseous stream by positive displacement, employing linear movement of the driveshaft.
Separator	A process vessel specifically designed to separate gaseous fluids from one or more liquid fluids produced from a well or as received via a pipeline. Generally, separators are operated at pressures greater than ambient air pressure.
Small business	A business entity (including its subsidiaries and affiliates) that has number of employees or average annual receipts below NAICS code-specific size standards established by the Small Business Administration. Size standards relevant to this ICR are listed below. For a complete listing of small business size standards, see https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf.
	NAICS Code 211111 - Crude Petroleum and Natural Gas Extraction: 1,250 employees NAICS Code 211112 - Natural Gas Liquid Extraction: 750 employees NAICS Code 213111 - Drilling Oil and Gas Wells: 1,000 employees NAICS Code 213112 - Natural Gas Liquid Extraction: $38.5-million annual receipts NAICS Code 486110 - Pipeline Transportation of Crude Oil: 1,500 employees NAICS Code 486210 - Pipeline Transportation of Natural Gas: $27.5-million annual receipts
Standard conditions	For the purposes of this ICR questionnaire, standard conditions may include any "standard" temperature between 288°K and 298°K and pressure between 1 bar (100 kilopascals) and 1 atmosphere. For emissions source tests, *standard conditions* refer to a temperature of 293°K (68°F) and a pressure of 1 atmosphere (101.3 kilopascals or 29.92 inches Hg).
Storage tank or vessel	A tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support.
Stripper well	A well that produces 15 barrels of oil equivalent (BOE) or less per day on average over a 12-month period.
Surface site	Any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.
Temporarily shut-in well	A well for which production is halted due to lack of a suitable market, a lack of available equipment to produce the product, or other reasons, but for which production may be resumed. The halt in production may extend for long periods of time, but the shut-in is "temporary" in that the well is not permanently plugged and production can resume when conditions are

Attachment 2C: Part 1 Questionnaire Definitions Sheet

Term	Definition
	favorable.
US Well ID (or API Well ID)	The uniquely assigned number for a well on the property (formerly known as the API Well ID).
Well	A hole drilled for the purpose of producing crude oil or natural gas, or a well into which fluids are injected.
Well site facility	A well surface site and, if applicable, all equipment at the centralized production area surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells at the well surface site that are under the control of the same person (or persons under common control) of the well surface site operator but that not are located at the well surface site (e.g., centralized tank batteries) and the gathering pipelines and equipment used to convey the fluids from the well surface site to the centralized production surface site.
Well surface site	One or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of this ICR, well surface site refers only to the well(s) and equipment at the disturbed area of land associated with the well(s) that are under the control of the same person (or persons under common control). The well surface site area does not include equipment at a centralized production surface site not located at the well surface site or equipment that is part of a gathering and boosting pipeline facility that may be co-located on the surface site but that is not under the control of the operator of the well(s).
Wet gas well	For the purposes of this ICR, a well that produces natural gas, other than coal bed methane, with a GOR greater than 100,000 scf/bbl but less than or equal to 1,000,000 scf/bbl.

Attachment 3A: Draft Part 2 Questionnaire Introduction/Instruction Sheet

Oil and Gas Information Collection Request: OMB Control No.

Part 2. Detailed Facility Survey

Introduction

This workbook contains the instructions and information collection forms used to collect information regarding processes, emission sources and controls used at existing oil and gas facilities. A brief description of each worksheet and their color-coded function is provided below. The questions generally refer to operations in 2016.

Worksheets

Name	**Details**
	INSTRUCTIONS
Intro	Overview of spreadsheets and general instructions
Acronyms	Provides listing of acronyms used in the sheets
Definitions	Provides definitions of key terms used on the sheets.
	FACILITY LEVEL INFORMATION – *Everyone should complete this section if your facility received a Part 2, Detailed Facility Survey request. You should review the definition of "facility" and any additional specific definitions that apply to you based on the industry segment to make sure the scope of operations that must be reported is understood before beginning to complete the survey. You should only complete a separate worksheet form for each separate facility selected for this Part 2 survey. Well operators, complete this form only for well site facilities that contain wells that were identified for this Part 2 survey, but include information for all wells (and other equipment) at that well site facility.*
Facility	This form should be completed first as this information may be used in other sheets. Section 1. Provide the parent company information requested Section 2. Provide the facility contact and operating information requested Section 3. Provide results for most recent gas sampling event. For natural gas processing facilities, provide inlet (feed) gas composition and outlet gas composition.
	CONTROL DEVICE INFORMATION – *Complete this sheet only for organic emissions control devices (flares, combustors, vapor recovery units, etc.; see definition) present at the facility.*
ControlDevice	This form should be completed second as the control device ID's entered in this sheet may be used in other sheets. Section 1. Provide the number of organic emission control devices at the facility Section 2. Provide the operating information requested for each control device. If emissions source test were conducted in the past 5 years, "attach source test report:" means that you will submit a copy of the test report within eGGRT system for this ICR. Section 3. This section is optional. Voluntarily provide the cost information requested for each control device.

Attachment 3A: Draft Part 2 Questionnaire Introduction/Instruction Sheet

	EMISSION SOURCE-SPECIFIC INFORMATION – *Complete these sheets only if the source or equipment is present at the facility required to complete this Part 2 survey. You must provide information regarding each source or equipment present at the facility regardless of whether the equipment is rented, leased, or separately owned. Generally **these forms should be completed with information readily available without additional testing except as noted in the underlined instructions below**.*
ProdnWells	Information sheet for production well surface sites, which is applicable only for production facilities. Include information for all production wells at the well site facility (including temporarily shut-in or permanently plugged and abandoned production wells) Section 1A. Provide the general well surface site information requested. Section 1B. Provide the cost information requested. Section 2. Provide the well-specific information requested. The request for production profiles in optional. EPA will use available oil and natural gas production profiles for the basin in which this well is located, general information on oil and natural gas production profiles from the state or similar basins, or other published sources will be used to create the production profile for wells unless alternative production profiles are provided. Section 3. Provide the well-specific information requested for well completion and workovers. Section 4. Provide the well-specific information requested for well testing and liquids unloading.
Injection-StorageWells	Information sheet for injection or storage well surface sites. Include information for all wells at the well site facility (including temporarily shut-in or permanently plugged and abandoned injection or storage wells) Section 1. Provide the general well surface site information requested. Section 2. Provide the well-specific information requested.
Tanks Separators	Source-specific information sheet for separators that discharge liquids to atmospheric storage tanks and for all storage tanks managing produced fluids located at the facility. **Information on separators that do not discharge fluids to an atmospheric storage tanks, "pressure vessels" or tanks used to store any type of glycol, amine, diesel fuel, gasoline, or inorganic chemical and should not be included in this tab.** Section 1. Provide the overall information requested for number of tanks and separators at the facility. These counts should reflect tanks/separators counts for those tanks for which information will be provided in subsequent sections of this tab. Section 2. Provide the tank- or separator-specific information requested. Section 3. Provide the feed material characteristics requested for each tank or separator. Section 4. *If feed material to an atmospheric tank comes from a pressurized system (e.g., a well, gas-liquid separator, compressor condensate, or pipeline fluids), you must perform pressurized feed sampling and flash gas compositional analysis according to the GPA methods specified in Section 4 each separator that produces 10 bbl/day or more of liquid material.* If the produced fluids entering an atmospheric storage tank is less than 10 bbl/day

	for each separator/tank at the facility then no pressurized sample is specifically required for that facility, with the following proviso: for facilities in the onshore natural gas transmission compression, transmission pipeline, or underground storage industry segments, if all tank/separators manage less than 10 bbl/day of produced fluids at all facilities within parent company, the parent company must collect one representative pressurized feed sample for flash analysis for any of its facilities. Provide the results of the flash composition analysis requested. Section 5. Provide the information requested for the controls, dump valve (separators), thief hatch (tanks) and pressure relief devices associated with each tank or separator. Section 6. If any direct emissions measurement data are available from an emissions source on a tank or separator, provide the information requested.
Pneumatics	Source-specific information sheet for pneumatic devices, including pneumatic controllers, pneumatic isolation valve actuators, and pneumatic pumps. Section 1. Indicate if you have any natural gas-driven pneumatic devices or pumps. If no, you are not required to (further) complete the pneumatics tab. Section 2. If you have any natural gas-driven pneumatic devices or pumps, *<u>you must complete the pneumatic device counts in Section 2 of this form based on actual counts at the facility. If this information is not readily available, you must visit the site and determine the actual pneumatic device count</u>.* Section 3. Provide the information requested regarding requested for natural gas-driven devices or pumps. Section 4. Provide the information on isolation valves based on controller design, manufacturer's information, and company records for each natural gas-driven pneumatic isolation valve actuator at the facility. Section 5. If any direct emissions measurement data are available from a pneumatic device, provide the information requested regarding those measurements.
AGRU	Source-specific information sheet for acid gas removal (or sweetening) units. Section 1. Provide the number of dehydration units and general facility requested. Section 2. Provide the AGRU-specific information requested for each AGRU at the facility. Section 3. If any direct emissions measurement data are available from the AGRU, provide the information requested regarding those measurements. Section 4. If any emissions estimates are available based on modelling software for the AGRU, provide the information requested regarding those estimates.
Dehyd	Source-specific information sheet for dehydration units. Section 1. Provide the number of dehydration units at the facility. Section 2. Provide the unit-specific information requested for each dehydration unit at the facility. Section 3. Provide the unit-specific information requested for emissions sources associated with each dehydration unit.

	Section 4. If any direct emissions measurement data are available from the dehydration unit, provide the information requested regarding those measurements. Section 5. Provide the wet gas analysis composition based on most recent gas sampling event or other available information. Section 6. If any emissions estimates are available based on modelling software for the dehydration unit, provide the information requested regarding those estimates.
EqLeaks	Source-specific information sheet for equipment component leaks. Section 1. Provide the general information regarding applicable rules on leak detection practices at the facility. Section 2. Provide the information regarding equipment component counts. *You must complete the equipment component counts in Section 2 of this form based on actual counts at the facility. If this information is not readily available, you must visit the site and determine the actual equipment component counts*. Section 3. Provide the information regarding equipment component counts aggregated by major equipment type. *You must complete the equipment component counts in Section 3 of this form based on actual counts at the facility. If this information is not readily available, you must visit the site and determine the actual equipment component counts*. Section 4. If any direct (quantitative) emissions measurement data are available for an equipment leak, provide the information requested regarding those measurements.
Comp	Source-specific information sheet for compressors (including vapor recovery compressors). Section 1. Provide the number of compressors of specified types at the facility. Section 2. Provide the compressor-specific information requested for each compressor at the facility. Section 3. If any direct emissions measurement data are available for compressor leak or vent sources, provide the information requested regarding those measurements. Section 4. Provide the requested compressor engine information for each compressor engine associated with a compressor at the facility. Section 5. If applicable, provide the requested information for centrifugal compressor wet seal replacements. Section 6. If applicable, provide the requested information for reciprocating compressor rod packing replacements.
Blowdown	Source-specific information sheet for equipment/pipeline blowdowns. Complete form based on available information for 2016. Section 1. Indicate if there were any equipment or piping blowdowns in 2016. Section 2. Provide the blowdown quantities requested for each blowdown category. Section 3. Indicate the blowdown emission reduction measures, if any, implemented to reduce blowdown emissions and the estimated quantity of emissions avoided.

Useful Tips

Printing

It may be useful to print out this sheet as well as the “Acronyms” and “Definitions” sheet for easy reference while completed the various forms. The blue tabs are formatted for printing; the other tabs are not formatted for printing.

Shading

Cells with grey shading are for table headers and calculated values. These cells are locked and cannot be altered. You should not need to enter data in these cells.

Cells with black shading are input cells that are not expected to be required based on answers to a related response. Values can be entered in these cells, but generally, black shading indicated that a response is not needed.

Cells with white/no shading are input cells. These cells should be completed based on the number of sources of a given type present at the facility.

Drop down pick lists

Many input values have predetermined lists of potential answers. A small triangle will appear on the right side of the cell that contains a pick list. Click on the triangle and the candidate options will appear. Select the best option of those provided. Some lists include “Other (specify)”. Please provide further information to describe the type of unit/device.

Data validation errors

Certain inputs have built-in data validation checks. For example, if a fraction is requested and you try to enter “98” for 98% rather than “0.98”, an error message will appear noting that the value expected must be between 0 and 1. If you have questions regarding the source of an error, please contact the Help Desk at {Help Desk email address}, or by calling {Help Desk phone number}, Monday through Friday during regular business hours.

Oil and Gas Information Collection Request

Part 2. Detailed Facility Survey

Acronym List for Detailed Facility Survey

Acronym	Definition
AAPG	American Association of Petroleum Geologists
AGRU	acid gas removal unit
API	American Petroleum Institute
AVO	audio, visual, olfactory
bbl	barrel
BOE	barrels of oil equivalence
Btu	British thermal unit
CARB	California Air Resources Board
CFR	Code of Federal Regulations
CH4	methane
CO2	carbon dioxide
EOR	enhanced oil recovery
g	gram
G&B	gathering and boosting
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program (40 CFR part 98)
GOR	gas-to-oil ratio
Hg	Mercury
kPa	kilopascals
lb	Pounds
lb/hr	pounds per hour
LPG	liquefied petroleum gas
MW	molecular weight
NG	natural gas
NGL	natural gas liquids
NHV	net heating value
OGI	optical gas imaging
psig	pounds per square inch gauge pressure
scf	standard cubic feet
scf/hr	standard cubic feet per hour
scfm	standard cubic feet per minute
ThOx	thermal oxidizer
VOC	volatile organic compound
°F	degrees Fahrenheit
°K	degrees Kelvin

Oil and Gas Information Collection Request

Part 2. Detailed Facility Survey

Key Terms and Definitions for Detailed Facility Survey

Term	Definition
Acid gas removal unit	A process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators. Also commonly referred to as a sweetening unit.
Adjust air to fuel ratio	Use of oxygen in the exhaust to control the combustion ratio (fuel use), thus reducing NOx emissions.
Air-assisted flare	A flare that intentionally introduces air at or near the flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame.
API gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density of various petroleum liquids, expressed in degrees. The formula for determining API gravity is: API gravity = (141.5/SG at 60°F) - 131.5, where SG is the specific gravity of the fluid.
Artificial lift	A wellbore deliquification technique that adds energy to the fluid column in a wellbore. Artificial-lift systems use a range of operating principles and include surface compression, sucker rod pumps, progressive cavity pumps, electric submersible pumps, jet pumps, and gas lift.
Associated gas	The natural gas which originates at oil wells and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation.
Atmospheric storage tank	A class of storage tanks that store materials at approximately atmospheric pressure. Atmospheric storage tanks may store liquids at ambient temperatures or at elevated temperatures (e.g., heated demulsification tank).
Balanced bellows spring-loaded relief valve	A type of reclosing pressure relief device that uses spring force to keep the relief valve closed until the set pressure is reached and that uses a bellows to protect the bonnet, spring and guide from the released fluids, thereby minimizing the effects of backpressure.
Barrel	A common unit of measurement for the volume of crude oil produced or processed. The volume of a barrel is equivalent to 42 US gallons.
Barrel of oil equivalent (BOE)	A unit of energy equal to 5.8-million British thermal units (5.8 MMBtu) based on the approximate energy released be burning one barrel of crude oil. For the purposes of this information collection request, you may use 1 BOE = 1 barrel of crude oil produced and 1 BOE = 5,800 scf of natural gas produced rather than using a direct energy conversion.
Basin	Geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map,

Attachment 3C: Draft Part 2 Questionnaire Definitions Sheet

Term	Definition
	Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.
Blowdown	The act of releasing gas from a well, process unit, or pipeline to reduce the pressure of the system or to prepare equipment for maintenance or cleaning, such as pigging.
Candlestick flare	A flare that has an elevated flare stack and open (exposed) flame.
Casing	Large-diameter steel pipe lowered into an open hole and cemented in place during the construction process to stabilize the wellbore.
Centralized production surface site	Any onshore surface site that obtains crude oil or a mixture of crude oil and natural gas directly from multiple well surface sites without a custody transfer, and includes all equipment used in the transportation, compression, stabilization, separation, storing or treating of crude oil and/or natural gas (including condensate) located at the surface site under the control of the same person (or persons under common control).
Centrifugal compressor	Any machine for raising the pressure of a gaseous stream by drawing in low pressure gas and discharging significantly higher pressure gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this information collection request.
Coal bed methane	Natural gas, predominantly methane, generated during coal formation and adsorbed in coal.
Coal seam	A stratum of coal thick enough to be profitably mined
Components (or equipment components)	Those parts of major process equipment that are typically included in leak detection and repair programs to reduce equipment leak emissions. *Equipment components* include, but are not limited to: valves, pumps, connectors (including flanges), meters, open-ended lines, and pressure relief devices.
Compressor	Any machine for raising the pressure of a gaseous stream by drawing in low pressure gas and discharging significantly higher pressure gas.
Compressor station	Any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in gathering or transmission pipelines, or into storage.
Condensate	Hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.
Continuous bleed pneumatic controller	A pneumatic controller that uses a continuous flow of pneumatic supply gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. For the purposes of this paper, continuous bleed controllers are further subdivided into two types based on their bleed rate. A low continuous bleed controller has a bleed rate of less than or equal to 6 standard cubic feet per hour (scf/hr). A high continuous bleed controller has a bleed rate of greater than 6 scf/hr.

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Term	Definition
Control device	Equipment that is utilized to recover or reduce emissions from a process stream that would otherwise be released to the atmosphere. For the purpose of completing the control device tab in this ICR, information is only required for each "organic emissions control device."
Conventional spring-loaded relief valve	A type of reclosing pressure relief device that uses a spring force to keep the relief valve closed until the set pressure is released and where the bonnet, spring and guide are exposed to the released fluids and the release system backpressure effects the relief set pressure.
Crude oil	A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending upon the characteristics of the crude stream, it may also include small amounts of non-hydrocarbons produced from oil, such as sulfur and various metals, drip gases, and liquid hydrocarbons produced from tar sands, gilsonite, and oil shale.
Custody transfer	The transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
Darcy	A standard unit of measure of permeability. One darcy describes the permeability of a porous medium through which the passage of one cubic centimeter of fluid having one centipoise of viscosity flowing in one second under a pressure differential of one atmosphere where the porous medium has a cross-sectional area of one square centimeter and a length of one centimeter. A millidarcy (mD) is one thousandth of a darcy and is a commonly used unit for reservoir rocks.
Directional well	A wellbore that has a planned deviation from primarily vertical so as to require the use of special tools or techniques to ensure that the wellbore path hits a particular subsurface target, typically located away from (as opposed to directly under) the surface location of the well.
Dry gas well	For the purposes of this ICR, a well that produces natural gas, other than coal bed methane, with a GOR greater than 1,000,000 scf/bbl.
Equipment	The set of articles or physical resources used in an operation or activity.
Enclosed flare/combustor	A flare or combustion device that uses a large stack enclosure to contain the devices flame within the stack enclosure. The bottom of the stack enclosure may be open or have openings to allow ambient air flow into the stack enclosure and the flare/flame tips are located near the base of the enclosure. This device is differs from a thermal oxidizer or incinerator due to the lack of a defined volume combustion chamber.
Enhanced oil recovery (or EOR)	The implementation of various techniques for increasing the amount of crude oil that can be extracted from an oil field, including gas injection, thermal injection, chemical injection, and plasma-pulse technology.
Facility	All of the pollutant-emitting activities which belong to the same industrial grouping (same two-digit code as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement), are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant

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Term	Definition
	emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1/4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. This general definition of *facility* is applicable to the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment industry segments, but does not include the pollutant-emitting activities associated with the following types of facilities that are defined specifically for this ICR: • *Well site facility* for the onshore petroleum and natural gas production industry segment. • *Gathering and boosting compression facility* for the onshore petroleum and natural gas gathering and boosting industry segment. • *Gathering and boosting pipeline facility* for the onshore petroleum and natural gas gathering and boosting industry segment. *Transmission pipeline facility* for the onshore natural gas transmission pipeline industry segment.
Field operator site	A centralized office or company that serves as the overall manager of the operations of one or more wells sites.
Field quality natural gas	Natural gas as produced at the wellhead or feedstock natural gas entering the natural gas processing plant.
Fixed operating and maintenance costs	Operating and maintenance costs that are independent of production levels.
Flare	A combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.
Flowback	The process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term *flowback* also means the fluids and entrained solids that emerge from a well during the flowback process. The *flowback period* begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The *flowback period* ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.
Formation type	The type of reservoir classified into one of the five following categories: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. All wells that produce hydrocarbon liquids with a gas-to-oil ratio less than 100,000 scf/barrel. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas

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Term	Definition
	wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge.
Gas liquid ratio	The ratio of the volume of natural gas that comes out of solution when liquid is stored at standard conditions. The liquid may be crude oil, condensate or produced water.
Gas-to-oil-ratio (GOR)	The ratio of the volume of natural gas that is produced or that comes out of solution when crude oil is extracted from a well equilibrated to standard conditions to the volume of hydrocarbon liquids (oil and condensate) produced after the natural gas comes out of solution. This is often calculated by dividing the measured natural gas production by the measured crude oil and condensate production.
Gas reservoir	A reservoir that produces natural gas or that produces natural gas and hydrocarbon liquids (oil and condensate) such that the gas-to-oil ratio of the material extracted from the reservoir is 100,000 scf/barrel of more.
Gas service	A piece of equipment that contains process fluid that is in the gaseous state at operating conditions.
Gas well	A well that produces natural gas or that produces natural gas and hydrocarbon liquids (oil and condensate) such that the gas-to-oil ratio is 100,000 scf/barrel of more.
Gathering and boosting compression facility (or Gathering and boosting compressor station)	Any grouping of equipment under the control of the same person (or persons under common control) at a single surface site that includes a permanent combination of one or more compressors that move natural gas at increased pressure through gathering pipelines.
Gathering and boosting pipeline facility	All natural gas gathering pipelines and associated equipment under the control of the same person (or persons under common control) within a single state, single county, and single hydrocarbon basin within the onshore petroleum and natural gas gathering and boosting industry segment except equipment that is located at a Gathering and Boosting Compression Facility. Associated equipment includes, but is not limited to, dehydrators, acid gas removal units, pig launchers/receivers, pressure vessels, and storage tanks, and may include equipment at well surface sites if that equipment is owned/operated by the Gathering and Boosting Pipeline Facility.
Gathering pipelines	A network of pipes that are used to convey petroleum and/or natural gas from production facilities to a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting pipeline facility.
Heated demulsification tank	A type of atmospheric storage vessel that uses heat to break oil-water emulsions so the oil can be accepted by the pipeline or transport.
Heater treater	A type of separator that uses heat to help separate natural gas and natural gas liquids from crude oil and water at a well surface site or centralized production surface site. Heater treaters generally operate above atmospheric pressure.
Heavy liquid service	A piece of equipment that is not in gas service or in light liquid service.
Heavy oil well	For the purposes of this ICR, a well that produces crude oil with a GOR of 300 scf/bbl or less.

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Term	Definition
High permeability gas reservoir	A natural gas reservoir with a permeability exceeding 0.1 millidarcy.
Horizontal well	A subset of the more general term "directional well" used where the departure of the wellbore from vertical exceeds about 80 degrees.
Hydraulic fracturing	The process of directing pressurized fluids containing any combination of water or other base fluid, proppant, and any added chemicals to penetrate a formations, generally to stimulate production, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.
Hydraulic refracturing	Conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.
Incinerator	An apparatus for burning waste material, especially industrial waste, at high temperatures until it is reduced to ash. Incinerators may be used to treat solid, liquid or gaseous waste and typically have a fixed volume combustion chamber.
Intermittent bleed controller	A pneumatic controller that does not have a continuous bleed, but rather vents only when the controller is actuated.
Isolation valve	A valve in a fluid handling system that stops the flow of process media to a given location, usually for maintenance or safety purposes.
Liquefied natural gas (LNG)	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.
Liquefied natural gas (LNG) storage	The oil and gas industry segment that liquefies natural gas, stores LNG in storage vessels, and/or re-gasifies LNG in onshore facilities that are not associated with LNG import or export,
Light liquid service	A piece of equipment that contains a liquid for which all of the following conditions apply: • The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F), • The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight, and The fluid is a liquid at operating conditions.
Light oil well	For the purposes of this ICR, a well that produces crude oil with a GOR greater than 300 scf/bbl but less than or equal to 100,000 scf/bbl.
Liquids unloading	• The process of removing water or condensate build-up from producing gas wells. Also known as "gas well deliquification" or "gas well dewatering."
LNG import and export equipment	The oil and gas industry segment that either receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system or that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States. The *LNG import and export equipment* industry segment includes both onshore and offshore equipment.

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Term	Definition
Low emissions combustion	Engine retrofit with high energy ignition systems, pre-combustion chambers, or other retrofit to the engine to improve efficiency and reduce NOx emissions.
Low excess air	Tuning of air within a combustion unit.
Low-NOx burner	Staging of air or fuel within the burner tip.
NAICS code	The numerical code of up to 6 digits used by the North American Industry Classification System (NAICS) for classifying business establishments by industry sector.
Natural gas (NG)	A naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.
Natural gas liquids (NGL)	The hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field quality natural gas.
Natural gas reburn	Recirculation of flue (natural) gas to reduce combustion temperature, thus reducing NOx emissions.
Net heating value (NHV)	The energy released as heat when a compound undergoes complete combustion with oxygen to form gaseous carbon dioxide and gaseous water (also referred to as lower heating value).
Non-Selective Catalytic Reduction (NSCR)	Reaction using a reducing agent to in the presence of a 3-way catalyst.
Nonstripper well	A well that produces more than 15 barrels of oil equivalent (BOE) per day on average over a 12-month period.
Oil reservoir	A reservoir that contains predominately hydrocarbon liquids (crude oil) such that the gas-to-oil ratio of the material extracted from the well is less 100,000 scf/barrel.
Oil well	A well that produces crude oil or that produces crude oil and associated gas such that the gas-to-oil ratio is less 100,000 scf/barrel.
Onshore	All facilities except those that are located in the territorial seas or on the outer continental shelf.
Onshore natural gas processing	The oil and gas industry segment that is engaged in the extraction of natural gas liquids from field quality natural gas, fractionation of mixed natural gas liquids to natural gas products, or both at an onshore facility. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not an onshore natural gas processing facility.
Onshore natural gas transmission compression (or Onshore natural gas transmission compressor station)	The oil and gas industry segment whose primary function is to move natural gas from production facilities, gathering and boosting facilities, natural gas processing plants, or other transmission compressor stations through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage using a combination of onshore compressors. Facilities in this industry segment are referred to as *Onshore natural gas transmission compressor stations* and these facilities may include equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids; however; the *Onshore natural gas transmission*

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Term	Definition
	compression industry segment does not include facilities that have compressors but that are in the production, gathering and boosting, or processing industry segments.
Onshore natural gas transmission pipeline	The oil and gas industry segment that operates onshore transmission pipelines.
Onshore petroleum and natural gas gathering and boosting	The oil and gas industry segment that uses onshore gathering pipelines and other equipment to collect petroleum and/or natural gas from onshore petroleum and natural gas production facilities and to compress, dehydrate, sweeten, or transport the crude oil , condensate and/or natural gas to a natural gas processing facility, a transmission pipeline or to a natural gas distribution pipeline. See also *Gathering and boosting compression facility* and *Gathering and boosting pipeline facility*
Onshore petroleum and natural gas production	The oil and gas industry segment responsible for the onshore extraction and production of crude oil, condensate, and/or natural gas and generally operate under NAICS code 211111 or 211112.
Organic emissions control device	A control device designed to recover or reduce emissions of organic pollutants, and includes, but is not limited to, traditional candlestick flares, enclosed flares, thermal oxidizers/incinerators, vapor recovery units and carbon adsorption systems. Catalyst systems used on compressor engines to reduce the emissions of CO, NOx or other inorganic pollutants are not considered to be an *organic emissions control device*.
Owner or operator	Any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.
Permeable gas reservoir	A natural gas reservoir that has a permeability greater than 0.1 millidarcy.
Pilot-operated relief valve	A type of reclosing pressure relief device that uses the process fluid itself, circulated through a pilot valve, to apply the closing force on the safety valve disc. The pilot valve is itself a small safety valve with a spring. The main valve does not have a spring but is controlled by the process fluid from pilot valve.
Plugged well	A well that has been sealed, typically by filling a portion of the well bore with cement, in order to permanently abandon the well following State, local or other regulatory body requirements for plugging and abandoning the well.
Plunger lift	A type of gas-lift method that uses a plunger that goes up and down inside the tubing and is used to remove water and condensate from a well. The plunger provides an interface between the liquid phase and the lift gas, minimizing liquid fallback.
Pneumatic controller	An automated pneumatic device used for maintaining a process condition such as liquid level, pressure, pressure difference and temperature.
Pneumatic device	Any device which generates or is powered by compressed air or natural gas which includes pneumatic controllers, pneumatic valve actuators, and pneumatic pumps.
Pneumatic pump	Devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers.

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Term	Definition
Pressure relief device	A valve, rupture disc or other device that is designed to open or release fluids when the pressure inside a piece of equipment reaches a set pressure to avoid safety hazards and equipment damage caused by exceeding the design limits of the equipment.
Pressure vessels	Vessel that are designed to store compressed gases or liquids, such as LNG, at pressures of 30 psig or higher without emissions to the atmosphere.
Producing well	A well for which crude oil or natural gas are actively flowing from a subsurface reservoir and through the wellhead valve.
Production profile	How the production level of a well or basin changes (or is expected to change) over the life of the well.
Production tubing	See "tubing"
Purge gas	Gas intentionally introduced either into the flare header system or at the base of the flare to maintain a constant flow of gas through the flare header and stack in order to prevent oxygen ingress.
Reciprocating compressor	A piece of equipment that increases the pressure of a gaseous stream by positive displacement, employing linear movement of the driveshaft.
Relief valve	Any reclosing pressure relief device such as a conventional spring-loaded relief valve, a balanced bellows spring-loaded relief valve, or a pilot-operated relief valve.
Rotary vane actuator	A type of pneumatic actuator that uses a system of chambers and vanes to produce rotational force on a shaft. The chambers typically contain a hydraulic fluid and pneumatic pressure is used to displace the hydraulic fluid from one chamber to apply pressure on one side of the shaft, which forces hydraulic fluid and venting of pneumatic gas from the other chamber. Also known as a displacement-type actuator.
Rupture disc	A non-reclosing differential-pressure device actuated by inlet static pressure and set to burst as a set inlet pressure. A rupture disk may be used alone, in parallel with, or in conjunction with reclosing pressure relief valves.
Selective catalytic reduction (SCR)	Reagent injection to reduce NOx in the presence of a catalyst.
Separator (or Gas-liquid separator)	A process vessel specifically designed to separate gaseous fluids from one or more liquid fluids produced from a well or as received via a pipeline. Generally, separators are operated at pressures greater than ambient air pressure.
Shale gas	Natural gas that is found trapped within shale formations, which are formations of fine-grained, clastic sedimentary rock composed of mud that is a mix of flakes of clay minerals and tiny fragments (silt-sized particles) of other minerals, especially quartz and calcite that is characterized by breaks along thin laminae or parallel layering or bedding less than one centimeter in thickness, called fissility.
Small business	A business entity (including its subsidiaries and affiliates) that has number of employees or average annual receipts below NAICS code-specific size standards established by the Small Business Administration. Size standards relevant to this ICR are listed below. For a complete listing of small business size standards, see https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf.

Attachment 3C: Draft Part 2 Questionnaire Definitions Sheet

Term	Definition
	NAICS Code 211111 - Crude Petroleum and Natural Gas Extraction: 1,250 employees NAICS Code 211112 - Natural Gas Liquid Extraction: 750 employees NAICS Code 213111 - Drilling Oil and Gas Wells: 1,000 employees NAICS Code 213112 - Natural Gas Liquid Extraction: $38.5-million annual receipts NAICS Code 486110 - Pipeline Transportation of Crude Oil: 1,500 employees NAICS Code 486210 - Pipeline Transportation of Natural Gas: $27.5-million annual receipts
Snap acting controller	A controller that acts as an on/off switch and is either fully open or fully closed. Most snap acting controllers, when functioning properly, do not have a continuous gas bleed and vent gas only when actuating and are, therefore, typically designed as intermittent bleed pneumatic devices.
Specific gravity	The ratio of the density of a fluid compared to the density of 4 °C water (i.e., 1.00 g/cm^3).
Standard conditions	For the purposes of this ICR questionnaire, standard conditions may include any "standard" temperature between 288°K and 298°K and pressure between 1 bar (100 kilopascals) and 1 atmosphere. For emissions source tests, *standard conditions* refer to a temperature of 293°K (68°F) and a pressure of 1 atmosphere (101.3 kilopascals or 29.92 inches Hg).
Stationary source	Any building, structure, facility, or installation which emits or may emit any air pollutant.
Steam-assisted flare	A flare that intentionally introduces steam prior to or at the flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame.
Steam injection	Injecting steam into combustion chamber to reduce flame temperature, thus reducing NOx emissions.
Storage tank or vessel	A tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. For the purposes of this ICR, pressure vessels (vessels designed to store fluids at pressures of 30 psig or higher) are not considered storage tanks.
Stripper well	A well that produces 15 barrels of oil equivalent (BOE) or less per day on average over a 12-month period.
Sub-basin category	A unique combination of Basin ID, the County and State, and the formation type. See definitions of "Basin" and "Formation type".
Surface site	Any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.
Temporarily shut-in well	A well for which production is halted due to lack of a suitable market, a lack of available equipment to produce the product, or other reasons, but for

Attachment 3C: Draft Part 2 Questionnaire Definitions Sheet

Term	Definition
	which production may be resumed. The halt in production may extend for long periods of time, but the shut-in is "temporary" in that the well is not permanently plugged and production can resume when conditions are favorable.
Thermal oxidizer	An apparatus with a fixed volume combustion chamber for burning waste gases at high temperatures. A thermal oxidizer is an incinerator designed to handle only gaseous waste streams.
Thief hatch	An opening in the top of a storage vessel that allows tank access for collecting (liquid or sediment) samples or measuring (liquid or sediment) levels.
Throttling controller	A controller that can provide a variable signal based on the deviation from the desired set point. A throttling controller is designed to hold an end device in an intermediate position and move it from any position to more or less open without a requirement to go fully open or fully shut every actuation cycle.
Tight gas reservoir	A natural gas reservoir (other than coal seam or shale formation) with a permeability of 0.1 millidarcy or less.
Total compressor power rating	The nameplate capacity of the compressor power output of the compressor drive.
Transmission pipeline	A Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994).
Transmission pipeline facility	For the purposes of this ICR, all onshore transmission pipelines that are physically connected within a given state and that is under the control of the same person (or persons under common control), and all equipment associated with the transmission pipelines (e.g., pig launchers/receivers, pressure vessels, and storage tanks) except equipment that is located at an Onshore Natural Gas Transmission Compression facility. The transmission pipeline facility starts or ends at the custody transfer point or state lines, whichever is applicable.
Tubing (or production tubing)	A tube installed within the casing and used as the primary conduit through which reservoir fluids are produced to surface.
Turbine operated actuator	A type of pneumatic actuator that uses a small turbine to actuate a valve, most commonly a gate valve. Pneumatic gas is used to spin the turbine blades and the turbine shaft turns gears that actuates the gate valve system.
Underground natural gas storage	The oil and gas industry segment that uses subsurface storage (include storage in depleted gas or oil reservoirs and salt dome caverns) of natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas).
Ultra-low NOx burner	Advanced staging of air or fuel within the burner tip.
Unassisted flare	A flare that does not have special nozzles or other hardware conveyance designed to intentionally supply air or steam prior at or near the flare tip.
Underground storage vessel	A storage vessel stored below ground.

Attachment 3C: Draft Part 2 Questionnaire Definitions Sheet

Term	Definition
US Well ID (or API Well ID)	The uniquely assigned number for a well on the property (formerly known as the API Well ID).
Variable operating and maintenance costs	Operating and maintenance costs that are proportional to production levels.
Vertical well	A well that is not turned horizontally at depth, allowing access to oil and gas reserves located directly beneath the surface access point.
Volatile organic compounds (VOC)	Any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions. Compounds that have been determined to have negligible photochemical reactivity, such as methane and ethane, are excluded from the define
Waste gas	Gas from facility operations that is directed to a flare or other control device for the purpose of disposing, treating, or recovering the gas.
Water injection	Injecting water into combustion chamber to reduce flame temperature, thus reducing NOx emissions.
Well	A hole drilled for the purpose of producing crude oil or natural gas, or a well into which fluids are injected.
Well bore length	The nominal length of the well from the wellhead to the termination of the well bore in the reservoir. For vertical wells, well bore length and well depth are equivalent. For directional or horizontal wells, well bore length will be greater than well depth.
Well completion	The process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.
Well depth	The vertical distance from the wellhead to the termination of the well bore in the reservoir.
Well head (or wellhead)	The piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.
Well shut-in pressure	The surface force per unit area exerted at the top of a wellbore when the wellhead valve is closed for at least 12 hours.
Well site facility	A well surface site and, if applicable, all equipment at the centralized production surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells at the well surface site that are under the control of the same person (or persons under common control) of the well surface site operator but that not are located at the well surface site (e.g., centralized tank batteries) and the gathering pipelines and equipment used to convey the fluids from the well surface site to the centralized production surface site.
Well surface site	One or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of this ICR, well surface site refers only to the well(s) and equipment at the

Attachment 3C: Draft Part 2 Questionnaire Definitions Sheet

Term	Definition
	disturbed area of land associated with the well(s) that are under the control of the same person (or persons under common control). The well surface site area does not include equipment at a centralized production surface site not located at the well surface site or equipment that is part of a gathering and boosting pipeline facility that may be co-located on the surface site but that is not under the control of the operator of the well(s).
Well testing	The determination of the production rate of a well or an assessment of reservoir characteristics for regulatory, commercial, or technical purposes. Well testing may or may not require venting of gas at the well surface site.
Wet gas well	For the purposes of this ICR, a well that produces natural gas, other than coal bed methane, with a GOR greater than 100,000 scf/bbl but less than or equal to 1,000,000 scf/bbl.
Workover	The process of performing major maintenance or remedial treatments on producing petroleum and natural gas wells to try to increase production. This process includes production tubing replacement, hydraulic refracturing, and snubbing and other well-intervention techniques.
Zero bleed pneumatic controller	A pneumatic controller that does not bleed the pneumatic gas to the atmosphere. These pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Attachment 3D: Draft Part 2 Questionnaire Facility Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Facility Sheet

1.) Parent Company General Information

Legal Name:	
Does this company meet the definition of small business?	(Picklist #2)
Dun and Bradstreet Number:	(Data Validation #16)
Mailing Address:	
Mailing City:	
Mailing State:	(Picklist #1)
Mailing Zip:	
Contact Name:	
Contact Title:	
Contact Phone:	(Data Validation #17)
Contact Phone 2:	(Data Validation #17)
Contact Email:	
Contact Email 2:	

2.) Facility General Information

Facility Name:	
Assigned Facility ICR ID:	
Facility Type:	(Picklist #3)
Other Facility Type, if applicable:	
Are greenhouse gas (GHG) emissions from this facility reported under 40 CFR part 98 subpart W for reporting year 2015?	(Picklist #2)
Facility GHGRP ID, if applicable:	(Data Validation #18)
Physical Address:	
Physical City:	
Physical State:	(Picklist #1)
Physical Zip:	
Physical County:	
Latitude (degrees decimal)	
Longitude (degrees decimal)	
Mailing Address:	
Mailing City:	
Mailing State:	(Picklist #1)
Mailing Zip:	
Contact Name:	
Contact Title:	
Contact Phone:	(Data Validation #17)
Contact Phone 2:	(Data Validation #17)
Contact Email:	
Contact Email 2:	

Attachment 3D: Draft Part 2 Questionnaire Facility Sheet

To the best of your ability based on existing records:	
Is this facility manned while in operation?	(Picklist #59)
What type of electricity is available at the facility?	(Picklist #60)
Number of months the facility operated in 2016	(Picklist #4)
Quantity of natural gas received by the facility in the 2016 calendar year (thousand standard cubic feet). [For storage facilities, this is the quantity placed into storage.]	(Data Validation #2)
Quantities for Centralized Production Surface Site (Onshore petroleum and natural gas production only)	(Data Validation #2)
Quantity of natural gas leaving the facility (sales) in the 2016 calendar year (thousand standard cubic feet). [For production facilities, this is the quantity extracted from all wells at the well surface site and also report the quantity leaving the centralized production surface site; for storage facilities, this is the quantity removed from storage.]	(Data Validation #2)
Quantities for Centralized Production Surface Site (Onshore petroleum and natural gas production only)	(Data Validation #2)
Quantity of all hydrocarbon liquids (crude oil and condensate, including NGLs) received by the facility in the 2016 calendar year (barrels).	(Data Validation #2)
Quantities for Centralized Production Surface Site (Onshore petroleum and natural gas production only)	(Data Validation #2)
Quantity of all hydrocarbon liquids (crude oil and condensate, including NGLs) leaving the facility (sales) in the 2016 calendar year (barrels). [For production facilities, this is the quantity extracted from all wells at the well surface site and also report the quantity leaving the centralized production surface site.]	(Data Validation #2)
Quantities for Centralized Production Surface Site (Onshore petroleum and natural gas production only)	(Data Validation #2)
Quantity of natural gas vented from the facility in the 2016 calendar year (thousand standard cubic feet).	(Data Validation #2)
For production facilities, quantity of produced water (thousand bbl/year in the 2016 calendar year).	(Data Validation #2)
For gathering and boosting pipeline facilities, miles of natural gas gathering and boosting pipeline [If the facility is a gathering and boosting compression facility, please enter 0.]	(Data Validation #2)
For transmission pipeline facilities, miles of natural gas transmission pipeline	(Data Validation #2)
Total number of pig launchers/receivers at the facility	(Data Validation #2)
What are the total voluntary CH_4 reductions achieved by the facility through EPA Gas STAR since 2012? (mt CH_4)	(Data Validation #2)

Attachment 3D: Draft Part 2 Questionnaire Facility Sheet

What are the total voluntary CH_4 reductions achieved by the facility through EPA Methane Challenge since 2015? (mt CH_4)	(Data Validation #2)

3.) Gas Composition - Complete according to most recent gas sampling event if available.

Sample Date (mm/dd/yyyy):	(Data Validation #14)
Component:	**Concentration (vol %)**
Carbon Dioxide	(Data Validation #11)
Nitrogen	(Data Validation #11)
Ethane	(Data Validation #11)
Propane	(Data Validation #11)
Isobutane	(Data Validation #11)
n-Butane	(Data Validation #11)
Isopentane	(Data Validation #11)
n-Pentane	(Data Validation #11)
Cyclopentane	(Data Validation #11)
n-Hexane	(Data Validation #11)
Cyclohexane	(Data Validation #11)
Heptanes	(Data Validation #11)
Methylcyclohexane	(Data Validation #11)
2,2,4-Trimethylpentane	(Data Validation #11)
Benzene	(Data Validation #11)
Toluene	(Data Validation #11)
Ethylbenzene	(Data Validation #11)
Xylene (isomers and mixtures)	(Data Validation #11)
o-Xylene	(Data Validation #11)
m-Xylene	(Data Validation #11)
p-Xylene	(Data Validation #11)
C8+ Heavies	(Data Validation #11)
Acetaldehyde	(Data Validation #11)
Carbon Disulfide	(Data Validation #11)
Carbonyl Sulfide	(Data Validation #11)
Ethylene Glycol	(Data Validation #11)
Formaldehyde	(Data Validation #11)
Napthalene	(Data Validation #11)

Attachment 3E: Draft Part 2 Questionnaire Control Device Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Control Device Sheet

1.) Facility Information

Facility ID (pulled from Facility sheet)	
Number of organic emissions control devices at the facility	(Data Validation #2)

2.) General Control Device Information - Complete for each Organic Emissions Control Device:

Control Device ID	Control Device Type	Specify Type if selected "Other"
	(Picklist #53)	

Release height (ft)	(Data Validation #2)
Stack diameter (ft)	(Data Validation #2)
Maximum flow capacity for device (scfm)	(Data Validation #2)
2016 Annual operating hours (hrs)	(Data Validation #2)
Estimated cumulative volume of waste gas sent to device in 2016 (scf)	(Data Validation #2)
Design Fractional Control Efficiency of Device	(Data Validation #11)
Control device outlet (exhaust) Temperature (deg F)	(Data Validation #2)
For carbon adsorbers, number of carbon beds or canisters on-line under typical operating conditions	(Data Validation #1)
For carbon adsorbers, mass of carbon in each bed or canister (lbs)	(Data Validation #2)
For Vapor Recovery Units, Minimum Rated Suction Pressure (psig)	(Data Validation #2)
For Vapor Recovery Units, Maximum Rated Suction Pressure (psig)	(Data Validation #2)
Average Net Heating Value of waste gas stream (Btu/scf)	(Data Validation #2)
Net Heating Value of purge/pilot gas (Btu/scf)	(Data Validation #2)
Purge Gas Flow Rate (scf/hr)	(Data Validation #2)
Pilot Gas Flow Rate (scf/hr)	(Data Validation #2)
Fraction of time control device is operated (lit) while waste gas flow is present	(Data Validation #11)
Maximum Heat Input Capacity to the Control Device (MMBtu/hr)	(Data Validation #2)
For thermal control devices, type of ignition source	(Picklist #54)
For thermal control devices, does it have a monitor to ensure a continuous flame?	(Picklist #2)
For thermal control devices, does it have monitoring to indicate when the device malfunctions or shuts down?	(Picklist #2)
For thermal control device, are there louvers, dampers, or other means of controlling ambient inlet air	(Picklist #2)

Attachment 3E: Draft Part 2 Questionnaire Control Device Sheet

For air assisted flares, type of air supply fan	(Picklist #55)
Is device equipped with a waste gas meter or other continuous parameter monitor? If yes, provide parameter(s) monitored.	(Picklist #2)
If yes, provide parameter(s) monitored.	
Were any emissions source tests conducted for this control device in past 5 years? If yes, please attach source test report.	(Picklist #2)
If yes, enter file name of attached report.	

3.) Control Device Cost Information – This section is optional. You may voluntarily provide information for any control device. The EPA is particularly interested in costs of controls installed in the past 5 years.

Control Device ID	Year Installed	Was Device Installed During Initial Construction?	Purchased Equipment Costs ($)
	(Data Validation #12)	(Picklist #2)	(Data Validation #2)

Total Capital Installed Cost ($)	Annual Operating and Maintenance Cost ($/yr in 2016)	Natural Gas Consumption Rate (MMscf/yr)
(Data Validation #2)	(Data Validation #4)	(Data Validation #4)

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Production Well Sheet

1A.) Production Well Surface Site Information:

Facility ID (pulled from Facility sheet)	
Number of wells at the well site.	(Data Validation #1)
Driving distance from field office (road miles).	(Data Validation #2)
Travel time to well site from field office (minutes).	(Data Validation #2)
Is the well site connected to a gathering and boosting or natural gas transmission pipeline?	(Picklist #2)
If not connected, why not?	(Picklist #61)
If not connected, distance to the nearest natural gas transmission pipeline or gathering and boosting pipeline (miles).	(Data Validation #2)
How frequently is well site visited by field office personnel?	(Picklist #5)
Is land owned or leased?	(Picklist #6)
Who owns the mineral rights?	(Picklist #62)
Is the well site subject to environmental regulations?	(Picklist #2)
Is the well site subject to State/Local Environmental Regulations?	(Picklist #2)
Is the well site subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
Is the well site subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
This row is intentionally blacked out. Please continue filling out this table below.	
How are produced waters managed?	(Picklist #7)
Number of wells at the well site.	(Data Validation #1)
Is there a combustion device on site?	(Picklist #2)
If combustion device is on site, what type of device is it?	(Picklist #63)
If other combustion device is on site, please list.	

1B.) Production Well Surface Site Cost Information: Provide the following information for the well surface site:

	Minimum	Average	Maximum
2016 Wellhead price for natural gas ($.$$/MMBtu)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
2016 Wellhead price for crude oil ($.$$/bbl)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
These rows are intentionally blacked out. Please continue filling out this table in the next row.			
2016 Average severance tax rate (%)		(Data Validation #11)	
2016 Average of other (additional) taxes, such as ad valorem taxes or production shares (%)		(Data Validation #11)	

Attachment 3F: Draft Part 2 Questionnaire Production Well Sheet

2.) General Well Information - Complete for each well at the well surface site.

US Well ID Number	
Basin ID	(Picklist #8)
County and State in which the Sub-basin is Located	(Picklist #9)
Sub-basin Formation Type	(Picklist #11)
Sub-basin ID	
Well Drilling Type	(Picklist #10)
Well Type	(Picklist #12)
Well depth (feet)	(Data Validation #2)
Type of well bore	(Picklist #64)
Well bore length (feet)	(Data Validation #2)
Well shut-in pressure (psig)	(Data Validation #2)
Well casing inside diameter (inches)	(Data Validation #2)
Well tubing inside diameter (inches)	(Data Validation #2)
What is the age (years) of the well at the well site?	(Data Validation #2)

For production rate and cumulative amounts, use metered data where available; otherwise use best available data.	
Natural gas production rate from well (daily average over last 30 days of operation). Use metered data where available; otherwise use best available data. (Mscf/day)	(Data Validation #2)
Total natural gas production from well in 2016. (Mscf)	(Data Validation #2)
Where is produced gas monitored?	(Picklist #13)
Oil and condensate production rate from well (daily average over last 30 days of operation) (bbl/day)	(Data Validation #2)
Total crude oil and condensate production rate from well in 2016 (bbls)	(Data Validation #2)
Where is oil/condensate flow monitored?	(Picklist #77)
Date of last production for shut-in or plugged wells (dd/mm/yyyy)	(Data Validation #14)
Well pressure in first 30 days production (psig)	(Data Validation #2)

Produced Gas Composition in first 30 days production					
CO_2 (% by vol)	CH_4 (% by vol)	C_2H_6 (% by vol)	VOC (% by vol)	HAP (% by vol)	H2S (% by vol)
(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)

Attachment 3F: Draft Part 2 Questionnaire Production Well Sheet

Produced Gas Composition in calendar year 2016 or last year of operation					
CO_2 (% by vol)	CH_4 (% by vol)	C_2H_6 (% by vol)	VOC (% by vol)	HAP (% by vol)	H2S (% by vol)
(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)	(Data Validation #11)

Gas to Oil Ratio in first 30 days production. For new wells, use best available data.	Gas to Oil Ratio in calendar year 2016 or last year of operation. For new wells, use best available data.	Oil Producing Wells Only	
		API gravity of produced crude oil	Disposition of casing head gas
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #14)

Annual fixed operating and maintenance cost for this well in 2016 ($/yr)	(Data Validation #2)	
Variable operating and maintenance cost for this well in 2016 ($/BOE)	(Data Validation #2)	
How many years after 2016 do you expect to continue production at this well?	(Picklist #83)	
Is there a representative production profile available for this well or basin? If yes, submit the profile in a separate file along with this survey	(Picklist #2)	
If yes, indicate the filename of the attached profile?	If yes, indicate the type of profile attached?	If other, specify?
	(Picklist #84)	

3.) Well Completion and Workover Information - Complete for each well at the well surface site.

US Well ID Number	
Date Well Completed (mm/dd/yyyy)	(Data Validation #14)
Type of Well Completion	(Picklist #15)
Date of Last Workover (mm/dd/yyyy)	(Data Validation #14)
Type of Well Workover	(Picklist #15)
Controls used for workovers	(Picklist #16)
Control Device ID (Enter "Temporary" if device only present for workover)	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Cost of last workover ($)	(Data Validation #2)

Attachment 3F: Draft Part 2 Questionnaire Production Well Sheet

4.) Well Testing and Liquids Unloading Information - Complete for each well at the well surface site.

US Well ID Number	
Date of last well testing (mm/dd/yyyy)	(Data Validation #14)
Anticipated date of next well testing (mm/dd/yyyy)	(Data Validation #14)
Annual hours for well testing (hours)	(Data Validation #1)
Controls used for last well testing	(Picklist #16)
Primary technique used for gas well liquids unloading?	(Picklist #17)
Number of well venting events for liquids unloading in past year (or since completion if <1 year old)	(Data Validation #1)
Controls used for well venting for liquids unloading	(Picklist #18)
Year Installed (for plunger lift, velocity tubing, or other assist method)	(Data Validation #3)
Total Capital Installed Cost ($)	(Data Validation #2)
Annual Operating and Maintenance Costs ($/yr in 2016)	(Data Validation #4)

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Injection/Storage Well Sheet

1.) Injection/Storage Well Facility Information:

Facility ID (pulled from Facility sheet)	
Number of injection/storage wells at the facility.	(Data Validation #1)
Driving distance from field office (road miles).	(Data Validation #2)
Travel time to well site from field office (minutes).	(Data Validation #2)
How frequently is well site visited by field office personnel?	(Data Validation #5)
Is the well site subject to environmental regulations?	(Picklist #2)
Is the well site subject to State/Local Environmental Regulations?	(Picklist #2)
Is the well site subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
Is the well site subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
Is there a combustion device on site?	(Picklist #2)
If combustion device is on site, what type of device is it?	(Picklist #63)
If other combustion device is on site, please list.	

2.) General Well Information - Complete for each injection or storage well at the facility.

US Well ID Number	
Injection/Storage Well Type	(Picklist #65)
Material being (or that was) injected/stored	(Picklist #66)
Specify if other	
Type of formation in which the material is injected or stored	(Picklist #67)
Specify if other	
Total gas storage capacity (MMscf)	(Data Validation #2)
Working gas capacity (MMscf)	(Data Validation #2)
Storage pressure at base capacity (psig)	(Data Validation #2)
Natural gas deliverability (MMscf/day)	(Data Validation #2)
Injection capacity (Maximum injection rate) (MMscf/day)	(Data Validation #2)
Liquids disposal capacity of formation (MMgallons)	(Data Validation #2)
Liquids injection capacity/rate (MMgallons/day)	(Data Validation #2)

Attachment 3H: Draft Part 2 Questionnaire Tanks Separator Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Tanks Separator Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Number of Separators at the Facility	(Data Validation #1)
Number of Atmospheric Storage Tanks <10 bbl/day at the facility	(Data Validation #1)
Number of Atmospheric Storage Tanks ≥10 bbl/day at the facility	(Data Validation #1)

2.) General Tank / Separator Information - Complete for each Tank / Separator on-site that stores or processes hydrocarbon materials or produced water. Separators should be included if the unit discharges liquids directly to an atmospheric storage tank.

Tank/Separator ID	
Vessel Type	(Picklist #19)
Does this vessel receive feed from another vessel onsite?	(Picklist #2)
Enter Tank/Separator IDs for the vessel(s) that feed to this tank or separator [Use a comma to delineate multiple IDs]	
Is the tank/separator subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
If no, specify reason	
Is the tank/separator subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
If no, specify reason	
Is the tank/separator subject to other environmental regulations?	(Picklist #2)
Is the tank/separator subject 40 CFR 63 subpart HH?	(Picklist #2)
Is the tank/separator subject to 40 CFR 60 Subpart Kb?	(Picklist #2)
Is the tank/separator subject to State/local or other environmental regulations?	(Picklist #2)
If State/local/other, specify rule	
Are emissions from the tank or separator sent to a control device?	(Picklist #2)
If yes, enter the Control Device ID for the primary control device associated with the tank/separator	(Picklist = Control Device ID's from ControlDevice Tab Table 2)

Provide the following emission rates based on modeled emissions or best available data:	
VOC (tons/yr potential to emit)	(Data Validation #2)
VOC (tons/yr actual)	(Data Validation #2)
CH4 (tons/yr actual)	(Data Validation #2)
C2H6 (tons/yr actual)	(Data Validation #2)
Benzene (tons/yr actual)	(Data Validation #2)
Toluene (tons/yr actual)	(Data Validation #2)
Ethylbenzene (tons/yr actual)	(Data Validation #2)
Xylenes (total) (tons/yr actual)	(Data Validation #2)
Hexane (tons/yr actual)	(Data Validation #2)
Total HAP (tons/yr actual)	(Data Validation #2)

Vessel capacity (gallons)	(Data Validation #2)
Average vessel hydrocarbon throughput (bbl/day)	(Data Validation #2)
Average vessel water throughput (bbl/day)	(Data Validation #2)

Is there a continuous monitor for the following:	
Gaseous flow rate to vessel	(Picklist #2)
Liquid feed flow rate to vessel	(Picklist #2)
Vessel operating pressure	(Picklist #2)
Liquid level in vessel	(Picklist #2)
Liquid flow rate from vessel	(Picklist #2)
Gaseous flow from vessel	(Picklist #2)

3.) Feed Material Characteristics - Complete for each Tank / Separator:

Tank/Separator ID	
Type of feed material	(Picklist #20)
If other, specify	
Reid vapor pressure of liquid feed material (psig)	(Data Validation #5)
Average pressure of feed material (psig)	(Data Validation #5)
Average temperature of feed material (°F)	(Data Validation #6)
Average specific gravity of liquid feed material (relative to water at 4 °C)	(Data Validation #7)
Average temperature of liquids in vessel (°F)	(Data Validation #6)
Average operating pressure of vessel (psig)	(Data Validation #5)

4.) Feed Material Flash Gas Properties - Complete the following table with direct measurement data for each feed material sent to an atmospheric tank using pressurized sample collection from each separator (or from a temporary separator, if no separator is used). Sample collection should follow GPA Method 2174 (Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography). The sampling rate must not exceed 60 mL/min. If your sample contains primarily crude oil or condensate, the sample must be analyzed using GPA Method 2103 (Tentative Method for the Analysis of Natural Gas Condensate Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography) with speciation of BTEX. If your sample contains primarily produced water, the sample must be analyzed using GPA Method 2286 (Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography). If you have performed testing of the feed material composition using the GPA Methods referenced above within the last 24 months, complete the following table based on the test results in-hand. If you have not performed testing of the feed material composition following the referenced GPA Methods, you must sample and analyze the pressurized separator fluid (storage vessel feed material) according to the specified GPA Method and report the results of the test in the following table.

Enter the Tank/Separator ID for the separator from which sample is collected (Enter "temporary" if a temporary separator was used)	(Picklist = “temporary” plus Tank/Separator ID’s from Table 2)

Enter Tank/Separator ID(s) for tanks for which this material is used as feed. [Use a comma "," to separate Tank IDs if material is sent to more than one tank. If liquids from separator pumped offsite, list "OFFSITE"]	
CH_4 (mol%)	(Data Validation #11)
C_2H_6 (mol%)	(Data Validation #11)
CO_2 (mol%)	(Data Validation #11)
VOC (mol%)	(Data Validation #11)
C3 (mol%)	(Data Validation #11)
C4 (mol%)	(Data Validation #11)
C5 (mol%)	(Data Validation #11)
C6 (mol%)	(Data Validation #11)
C7 (mol%)	(Data Validation #11)
C8 (mol%)	(Data Validation #11)
C9 (mol%)	(Data Validation #11)
C10+ (mol%)	(Data Validation #11)
Benzene (mol%)	(Data Validation #11)
Toluene (mol%)	(Data Validation #11)
Ethylbenzene (mol%)	(Data Validation #11)
Xylene (mol%)	(Data Validation #11)
O_2 (mol%)	(Data Validation #11)
N_2 (mol%)	(Data Validation #11)
n-Hexane (mol%)	(Data Validation #11)
Density (lb/scf)	(Data Validation #8)
Gas Liquid Ratio of Flashed Pressurized Sample (scf/bbl)	(Data Validation #2)
Produced Liquid Type	(Picklist #21)

5.) Leakage, Controls and Inspection - Complete for each Tank / Separator:

Tank/Separator ID	
Disposition of natural gas (or other off-gas)	(Picklist #22)
Control Device ID [Enter "Not applicable" if recovered without use of a vapor recovery compressor]	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Dump valve inspection frequency	(Picklist #23)
Hours dump valve stuck in 2016 (Actual or best engineering estimate)	(Data Validation #1)
Type of thief hatch	(Picklist #24)
Thief hatch monitoring or inspection frequency	(Picklist #23)
Pressure release setting for thief hatch (psig)	(Data Validation #1)
What kind of alarms exist to let operator know the thief hatch is open?	(Picklist #68)
If other, please describe	
Hours the thief hatch was open in 2016	(Data Validation #1)
Additional measures that have been taken to limit dump valve openings	

Attachment 3H: Draft Part 2 Questionnaire Tanks Separator Sheet

Type of pressure relief device	(Picklist #69)
Pressure relief device monitoring or inspection frequency	(Picklist #23)
Pressure release setting for the pressure relief device (report lowest pressure PRD if multiple PRD) (psig)	(Data Validation #2)
Number of releases from pressure relief device in 2016	(Data Validation #1)
Were any direct measurements of emissions from vessel taken in last 5 years? If yes, complete next section.	(Picklist #2)

6.) Direct Emissions Measurements - Complete for each Tank / Separator, as applicable, for which emissions measurement data are available.

Tank/Separator ID	(Picklist = Tank/Separator ID's from Table 2)
Source/Vent Description	
Date of measurement	(Data Validation #14)
Source total volumetric flow rate of emissions (scf/hr)	(Data Validation #2)

VOC (tons/yr actual)	CH4 (tons/yr actual)	C2H6 (tons/yr actual)	Benzene (tons/yr actual)	Toluene (tons/yr actual)	Ethylbenzene (tons/yr actual)	Xylenes (total) (tons/yr actual)	Hexane (tons/yr actual)	Total HAP (tons/yr actual)
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

7.) Process Emissions Simulations - Complete for each tank and attach software output results.

Unit ID
(Picklist = Tank/Separator ID's from Table 2)

Modeling Software		Flashing Emissions (lb/hr)		
	If Other, Specify:	Total VOC	Total HAP	Total BTEX
(Picklist #70)		(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Breathing Emissions (lb/hr)			Working Emissions (lb/hr)		
Total VOC	Total HAP	Total BTEX	Total VOC	Total HAP	Total BTEX
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Is there a file available for this unit ID? If yes, enter the filename in the next column	(Picklist #2)
Filename for tank process emissions simulation software output results	

Attachment 3I: Draft Part 2 Questionnaire Pneumatics Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Pneumatics Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Does the facility have any natural gas-driven pneumatic devices or pumps?	(Picklist #2)

2.) Pneumatic Controllers/Devices/Pumps Inventory, provide the count of each of the following:

Type of Pneumatic Device	**Total Number of Natural Gas-Driven Devices**	**Are there air-driven pneumatic devices at the facility?**
Snap acting, intermittent bleed controllers	(Data Validation #1)	(Picklist #2)
Snap acting, continuous bleed controllers	(Data Validation #1)	
Throttling low continuous bleed controllers	(Data Validation #1)	
Throttling high continuous bleed controllers	(Data Validation #1)	
Throttling intermittent bleed controllers	(Data Validation #1)	
Throttling no-bleed controllers (discharge to downstream gas line)	(Data Validation #1)	
Rotary vane isolation valve actuators	(Data Validation #1)	**Are there air-driven isolation valve actuators at the facility?**
Turbine operated isolation valve actuators	(Data Validation #1)	(Picklist #2)
Other pneumatic isolation valve actuators	(Data Validation #1)	
Chemical injection piston pumps that are operated for 90 days per calendar year or more	(Data Validation #1)	**Are there air-driven pneumatic pumps at the facility?**
Chemical injection piston pumps that are operated for less than 90 days per calendar year	(Data Validation #1)	(Picklist #2)
Chemical injection diaphragm pumps that are operated for 90 days per calendar year or more	(Data Validation #1)	
Chemical injection diaphragm pumps that are operated for less than 90 days per calendar year	(Data Validation #1)	
Liquid circulation (Kimray) pumps that are operated for 90 days per calendar year or more	(Data Validation #1)	
Liquid circulation (Kimray) pumps that are operated for less than 90 days per calendar year	(Data Validation #1)	

3.) General Pneumatic Controllers/Devices/Pumps Information:

How does the facility determine if a device is intermittent or continuous bleed?	(Picklist #25)
How does the facility determine if a continuous bleed device is high or low bleed?	(Picklist #25)

Attachment 3I: Draft Part 2 Questionnaire Pneumatics Sheet

What work practices does the facility employ to identify malfunctioning controllers (e.g., intermittent devices continuously venting)?	(Picklist #26)
If other, describe	
How many controllers were found malfunctioning (leaking or excessively bleeding) in the past year?	(Data Validation #1)
What is the typical natural gas supply pressure for the pneumatic devices (psig)?	(Data Validation #2)
Does the facility use practices to minimize natural gas emissions from pneumatic devices or pumps?	(Picklist #71)
If other, describe	
Were any direct measurements of emissions from pneumatic devices taken in past 5 years? If yes, complete Section 5 below.	(Picklist #2)
Is the well site subject to environmental regulations?	(Picklist #2)
Is the well site subject to State/Local Environmental Regulations?	(Picklist #2)
Are the pneumatic controllers subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
Are the pneumatic controllers subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
Are the pneumatic controllers subject to both state regulation and 40 CFR 60 subpart OOOO/OOOOa?	(Picklist #2)
Are pneumatic controllers controlled?	(Picklist #2)
Are pneumatic pumps controlled?	(Picklist #2)
If pneumatics are controlled, specify the control device on number of pneumatic devices are controlled by that device:	
Control Device ID1	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Number of devices of specified type controlled by control device ID1	(Data Validation #1)
Control Device ID2	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Number of devices of specified type controlled by control device ID2	(Data Validation #1)
Control Device ID3	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Number of devices of specified type controlled by control device ID3	(Data Validation #1)

4.) Pneumatically Driven Isolation Valve Actuations in 2016. Provide the following information based on controller design, manufacturer's information, and company records for each natural gas driven pneumatic isolation valve actuator.

Isolation Valve/Actuator ID	
Isolation Valve Actuator Type	(Picklist #27)
Specify if other	

Gas Usage per Cycle based on manufacturers information (scf/psi)	(Data Validation #2)
Based on best available data, cumulative number of actuation cycles in 2016 (or most recent operating year).	(Data Validation #1)
Gas supply pressure for pneumatic device (psig)	(Data Validation #2)

5.) Direct Measurements - Complete for each Natural Gas-Driven Pneumatic Controllers/Devices/Pumps, as applicable, for which measurement data are available.

Source Description or ID	
Pneumatic Device Type	(Picklist #28)
Pneumatic Device Type (Include if "other" device type)	
Measurement Method	(Picklist #29)
Number of Devices [included in measurement]	(Data Validation #1)
Measured NG emission rate [for all devices included in measurement] (scf/hr)	(Data Validation #2)
Make and Model Number of Device(s)	

Attachment 3J: Draft Part 2 Questionnaire Acid Gas Removal Unit (AGRU) Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Acid Gas Removal Unit (AGRU) Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Number of acid gas removal units at the facility	(Data Validation #1)

2.) Pneumatic Controllers/Devices/Pumps Inventory, provide the count of each of the following:

Unit ID	AGRU Type	
		If Other, Specify:
	(Picklist #30)	

Is the AGRU subject to environmental regulations?	(Picklist #2)
Is the AGRU subject to State/Local Environmental Regulations?	(Picklist #2)
Is the AGRU subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
Is the AGRU subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
Is the AGRU subject to 40 CFR 60 subpart LLL?	(Picklist #2)
This column is intentionally blacked out. Please continue filling out this table in the next column.	
Contactor Tower Pressure (psig)	(Data Validation #2)
Circulation Rate of Solution (gal/min)	(Data Validation #2)
Operating Hours in 2016	(Data Validation #9)
Relative selectivity of H2S over CH4 (Mass ratio)	(Data Validation #2)
Relative selectivity of CO2 over CH4 (Mass ratio)	(Data Validation #2)
Relative selectivity of Mercury over CH4 (Mass ratio)	(Data Validation #2)
Average volumetric flow rate of feed natural gas (scfm)	(Data Validation #2)
H2S concentration in feed gas (% by vol)	(Data Validation #11)
CO2 concentration in feed gas (% by vol)	(Data Validation #11)
Average volumetric flow rate of treated natural gas (scfm)	(Data Validation #2)
H2S concentration in treated gas (% by vol)	(Data Validation #11)
CO2 concentration in treated gas (% by vol)	(Data Validation #11)

Primary purpose of AGR		Disposition of AGRU tail gas	
Primary purpose of AGR (Select)	If Other, Specify:	Disposition of AGRU tail gas (Select)	If Other, Specify:
(Picklist #31)		(Picklist #32)	

Are emissions from the AGRU or subsequent tail gas treatment unit sent to a control device?	If yes, enter the Control Device ID for the primary control device associated with the unit	Were any direct measurements of emissions from vessel taken in past 5 years? If yes, complete next section.

(Picklist #2)	(Picklist = Control Device ID's from ControlDevice Tab Table 2)	(Picklist #2)

3.) Direct Emissions Measurements - Complete for each AGRU for which emissions measurement data are available.

Unit ID	
Source Description	
Date of Measurement (mm/dd/yyyy)	(Data Validation #14)

H_2S emission rate (lb/hr)	SO_2 emission rate (lb/hr)	CO_2 emission rate (lb/hr)	CH_4 emission rate (lb/hr)	Ethane emission rate (lb/hr)	VOC emission rate (lb/hr)	Benzene emission rate (lb/hr)
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Toluene emission rate (lb/hr)	Ethylbenzene emission rate (lb/hr)	Xylenes (total) emission rate (lb/hr)	Carbonyl sulfide emission rate (lb/hr)	Carbon disulfide emission rate (lb/hr)	Total HAP emission rate (lb/hr)	Hexane emission rate (lb/hr)
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Please attach test report and provide file name for attachment	

4.) Process Emissions Simulations - Complete for each AGRU and attach software output results.

Unit ID	Are modeled emissions available for this unit?	Modeling Software	
			If Other, Specify:
	(Picklist #2)	(Picklist #72)	

Uncontrolled Emissions (lb/hr)									
Methane	CO2	Total VOC	Total HAP	Benzene	Total BTEX	Hydrogen Sulfide	Carbonyl Sulfide	Carbon Disulfide	SO2
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Controlled Emissions (if applicable) (lb/hr)

Attachment 3J: Draft Part 2 Questionnaire Acid Gas Removal Unit (AGRU) Sheet

Methane	CO2	Total VOC	Total HAP	Benzene	Total BTEX	Hydrogen Sulfide	Carbonyl Sulfide	Carbon Disulfide	SO2
(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Is there a file available for this unit ID? If yes, enter the filename in the next column	
Filename for AGRU process emissions simulation software output results	

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Dehydration (Dehy) Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Number of dehydrators at the facility	(Data Validation #1)
Does the facility handle, process, or store black oil exclusively (including use or generation of gas from black oil)?	(Picklist #2)
Does the facility have actual annual average natural gas and hydrocarbon throughputs of less than 18,400 standard m^3/day and 39,700 liters/day, respectively?	(Picklist #2)
Is facility at an area or major source for HAPs?	(Picklist #78)

2.) General Dehydrator Information - Complete for each Dehydrator:

Unit ID	
Dehydrator Type	(Picklist #33)
If Other, Specify:	
Is the Dehydrator subject to environmental regulations?	(Picklist #2)
Is the Dehydrator subject to State/Local Environmental Regulations?	(Picklist #2)
This column is intentionally blacked out. Please continue filling out this table in the next column.	
Is the Dehydrator subject to 40 CFR 63 subpart HH or subpart HHH?	(Picklist #2)
Date of Construction/Reconstruction (mm/dd/yyyy)	(Data Validation #14)
Does the Dehydrator emit more than or less than 1 ton per year of benzene?	(Picklist #81)
Is the Dehydrator subject to 40 CFR 63 subpart HH and located within an Urban Area/Urban Cluster?	(Picklist #2)
What is the Dehydrator's actual annual average natural gas flow rate range?	(Picklist #80)
Average volumetric flow rate of feed natural gas (scfm)	(Data Validation #2)
2016 Annual Operating Hours (hrs)	(Data Validation #9)
Contactor Tower Pressure (psig)	(Data Validation #2)
Temperature of Feed Gas Stream (°F)	(Data Validation #2)
Pressure of Feed Gas Stream (psig)	(Data Validation #2)
Is feed gas saturated or subsaturated?	(Picklist #87)
Circulation Rate of Solution (gal/min)	(Data Validation #2)
Liquid Circulation Pump Type	(Picklist #88)
Stripper Gas Consumption Rate (scfm)	(Data Validation #2)
Stripper Gas Methane Composition (% by vol)	(Data Validation #11)
H2O concentration in feed gas (lb H2O/MMSCF)	(Data Validation #2)
CO2 concentration in feed gas (% by vol)	(Data Validation #11)
CH4 concentration in feed gas (% by vol)	(Data Validation #11)
Average volumetric flow rate of treated natural gas (scfm)	(Data Validation #2)
H2O concentration in treated gas (lb H2O/MMSCF)	(Data Validation #2)
CO2 concentration in treated gas (% by vol)	(Data Validation #11)
CH4 concentration in treated gas (% by vol)	(Data Validation #11)

Attachment 3K: Draft Part 2 Questionnaire Dehydration (Dehy) Sheet

Were any direct measurements of emissions from any dehydrator (glycol or desiccant) taken in past 5 years? If yes, complete the direct measurements section.	(Picklist #2)

3.) Glycol Dehydrator Information - Complete for each Glycol Dehydrator:

Unit ID	
Does the unit have a flash tank separator?	(Picklist #2)
If yes, provide natural gas recovery efficiency (percent)	(Data Validation #11)
If yes, provide disposition of recovered natural gas.	(Picklist #34)
If Other, Specify:	
Glycol reboiler fuel gas type	(Picklist #35)
If Other, Specify:	
Glycol reboiler fuel gas consumption rate (scfm)	(Data Validation #2)
Disposition of regenerator exhaust	(Picklist #36)
If Other, Specify:	
Control Device ID (if applicable)	(Picklist = Control Device ID's from ControlDevice Tab Table 2)
Emission reduction work practices used	(Picklist #37)
If Other, Specify:	

4.) Direct Emissions Measurements - Complete for each dehydrator for which emissions measurement data are available.

Unit ID	
Source/Vent Description	
Date of Measurement (mm/dd/yyyy)	(Data Validation #14)
CO_2 emission rate (lb/hr)	(Data Validation #2)
CH_4 emission rate (lb/hr)	(Data Validation #2)
Ethane emission rate (lb/hr)	(Data Validation #2)
VOC emission rate (lb/hr)	(Data Validation #2)
Benzene emission rate (lb/hr)	(Data Validation #2)
Toluene emission rate (lb/hr)	(Data Validation #2)
Ethylbenzene emission rate (lb/hr)	(Data Validation #2)
Xylenes (total) emission rate (lb/hr)	(Data Validation #2)
Hexane emission rate (lb/hr)	(Data Validation #2)
Total HAP emission rate (lb/hr)	(Data Validation #2)
Please attach test report and provide file name for attachment	

5.) Wet Gas Composition - Complete according to most recent gas sampling event if available.

Sample Date (mm/dd/yyyy):	(Data Validation #14)
Component:	**Concentration (vol %)**

Attachment 3K: Draft Part 2 Questionnaire Dehydration (Dehy) Sheet

Carbon Dioxide	(Data Validation #11)
Nitrogen	(Data Validation #11)
Ethane	(Data Validation #11)
Propane	(Data Validation #11)
Isobutane	(Data Validation #11)
n-Butane	(Data Validation #11)
Isopentane	(Data Validation #11)
n-Pentane	(Data Validation #11)
Cyclopentane	(Data Validation #11)
n-Hexane	(Data Validation #11)
Cyclohexane	(Data Validation #11)
Heptanes	(Data Validation #11)
Methylcyclohexane	(Data Validation #11)
2,2,4-Trimethylpentane	(Data Validation #11)
Benzene	(Data Validation #11)
Toluene	(Data Validation #11)
Ethylbenzene	(Data Validation #11)
Xylene (isomers and mixtures)	(Data Validation #11)
o-Xylene	(Data Validation #11)
m-Xylene	(Data Validation #11)
p-Xylene	(Data Validation #11)
C8+ Heavies	(Data Validation #11)
Acetaldehyde	(Data Validation #11)
Carbon Disulfide	(Data Validation #11)
Carbonyl Sulfide	(Data Validation #11)
Ethylene Glycol	(Data Validation #11)
Formaldehyde	(Data Validation #11)
Napthalene	(Data Validation #11)

6.) Process Emissions Simulations - Complete for each dehydrator and attach software output results.

Unit ID	
Are modeled emissions available for this unit?	(Picklist #2)
Modeling Software	(Picklist #72)
If Other, Specify:	
Uncontrolled Emissions (lb/hr)	
Total VOC	(Data Validation #2)
Total HAP	(Data Validation #2)
Benzene	(Data Validation #2)
Total BTEX	(Data Validation #2)
Controlled Emissions (lb/hr)	
Total VOC	(Data Validation #2)
Total HAP	(Data Validation #2)
Benzene	(Data Validation #2)
Total BTEX	(Data Validation #2)

Attachment 3K: Draft Part 2 Questionnaire Dehydration (Dehy) Sheet

Is there a file available for this unit ID? If yes, enter the filename in the next column	
Filename for dehydrator process emissions simulation software output results	

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Equipment Leaks (EqLeaks) Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Are equipment leaks at the facility subject to environmental regulations?	(Picklist #2)
Are equipment leaks subject to State/Local Environmental Regulations?	(Picklist #2)
Are equipment leaks subject to 40 CFR 60 subpart KKK?	(Picklist #2)
Are equipment leaks subject to 40 CFR 60 subpart OOOO?	(Picklist #2)
Are equipment leaks subject to 40 CFR 60 subpart OOOOa?	(Picklist #2)
Are equipment leaks subject to 40 CFR 63 subpart HH?	(Picklist #2)
This row is intentionally blacked out. Please continue filling out this table below.	
Does the facility conduct regular audio-visual-olfactory (AVO) inspections for leak?	(Picklist #2)
Frequency of AVO inspections.	(Picklist #23)
Does the facility conduct routine inspections (Method 21, OGI, or other instrumented method) to identify leaking equipment components?	(Picklist #2)

If yes, provide the following information by component type:	Gas or Light Liquid Valves	Gas or Light Liquid Connectors	Gas or Light Liquid Pressure-relief Valves	Pumps	Other components in gas or light liquid service	Heavy liquid components
Frequency of inspections.	(Picklist #23)	(Picklist #23)	(Picklist #23)	(Picklist #23)	(Picklist #23)	(Picklist #23)
Monitoring method used.	(Picklist #38)	(Picklist #38)	(Picklist #38)	(Picklist #38)	(Picklist #38)	(Picklist #38)
If Other method, specify.						

Has this facility performed emissions testing for equipment leaks in the last five years? If yes, complete the direct measurements section.	(Picklist #2)

2.) Equipment Leak Inventory Information - Provide component counts by service type for all components meeting the specified criteria based on actual component counts:

Service / Component Type	Total Number of Components contacting a process fluid or gas that contains 5 percent by weight or more of any of the following pollutants: VOC, CH_4, CO_2	For natural gas processing plants only: Total Number of Components contacting a process fluid or gas that is at least 10 percent VOC by weight	Total Number of Components Monitored for Leaks During Most Recent Monitoring Survey	Total Number of Components Found Leaking During Most Recent Monitoring Survey	Definition of Leak used for Monitoring Components	Other (Specify) (ppmv)

Attachment 3L: Draft Part 2 Questionnaire Equipment Leaks (EqLeaks) Sheet

Gas Service Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Connectors (other than flanges)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Flanges	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Open-ended Lines	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Pressure-relief Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Pumps	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Meters	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Vapor Recovery Compressors	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Gas Service Other	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Connectors (other than flanges)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Flanges	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Open-ended Lines	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Pressure-relief Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Pumps	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)

Attachment 3L: Draft Part 2 Questionnaire Equipment Leaks (EqLeaks) Sheet

Light Liquid Service Meters	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Vapor Recovery Compressors	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Light Liquid Service Other	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Connectors (other than flanges)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Flanges	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Open-ended Lines	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Pressure-relief Valves	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Pumps	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Meters	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Vapor Recovery Compressors	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)
Heavy Liquid Service Other	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Picklist #39)	(Data Validation #1)

3.) Provide the following equipment counts based on actual equipment and equipment components counts at the facility:

Major Equipment Type	Total Number of Each Major Equipment Type	Total Number of Valves	Total Number of Connectors (including flanges)	Total Number of Open-Ended Lines
Natural gas Wellheads	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)

Natural gas Separators	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Natural gas Meters/piping runs	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Natural gas Tanks	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Natural gas Compressors	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Natural gas In-line heaters	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Natural gas Dehydrators	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Wellheads	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Separators	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Meters/piping runs	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Tanks (other than heater-treaters)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Heater-treaters	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)
Crude oil Headers	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)	(Data Validation #1)

4.) Direct Emissions Measurements - Complete for each component or equipment type, as applicable, for which most recent direct emissions measurement data are available.

Major Equipment Type	Component type	Service type	Additional Source Description (if other or more information needs to be related)	Measurement method
(Picklist #41)	(Picklist #42)	(Picklist #40)		(Picklist #43)

Measured Emissions Rate (scf/hr)	Measurement date (mm/dd/yyyy)	Measurement cost ($)
(Data Validation #2)	(Data Validation #14)	(Data Validation #2)

Attachment 3M: Draft Part 2 Questionnaire Compressor Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Compressor Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Number of reciprocating compressors at the facility	(Data Validation #1)
Number of other compressors at the facility	(Data Validation #1)
Number of centrifugal compressors at the facility	(Data Validation #1)

2.) General Compressor Information - Complete for each Compressor:

Compressor Name/ID	
Compressor Type	(Picklist #44)
If Other, Specify:	
Operational Service	(Picklist #75)
If Other, Specify:	
Are any current environmental regulations applicable to the compressor?	(Picklist #2)
Is the compressor subject to State/Local Environmental Regulations?	(Picklist #2)
Is the compressor subject to 40 CFR part 60 subpart OOOO?	(Picklist #2)
Is the compressor subject to 40 CFR part 60 subpart OOOOa?	(Picklist #2)
Is the compressor subject to 40 CFR part 60 subpart KKK?	(Picklist #2)
Date of Installation (mm/dd/yyyy)	(Data Validation #14)
Power output of compressor driver (hp)	(Data Validation #1)
Are there add-on emissions controls or recovery used on any of the compressor vent sources?	(Picklist #2)
If yes, identify the compressor sources controlled/recovered and the control device ID [use "Not Applicable" if vent gas is recovered without use of recovery compressor].	
Wet seal degassing vent	(Picklist #2)
Wet seal degassing vent Control Device ID	(Picklist = Control Device ID’s)
Rod packing vent	(Picklist #2)
Rod packing vent Control Device ID	(Picklist = Control Device ID’s)
Blowdown vent	(Picklist #2)
Blowdown vent Control Device ID	(Picklist = Control Device ID’s)
Isolation valve leakage	(Picklist #2)
Isolation valve leakage Control Device ID	(Picklist = Control Device ID’s)
Other compressor source	(Picklist #2)
Other compressor source Control Device ID	(Picklist = Control Device ID’s)
Were direct emissions measurements made for compliance with the RY 2016 GHGRP in 40 CFR 98 Subpart W?	(Picklist #2)

If yes, please provide the Compressor ID or Unique Name used in the RY 2016 report (if different than the ID provided in this form).	
If no, please provide the total time the compressor was in operating-mode in RY 2016. (hours)	(Data Validation #9)
If no, please provide the total time the compressor was in standby-pressurized-mode in RY 2016. (hours)	(Data Validation #9)
If no, please provide the total time the compressor was in not-operating-depressurized-mode in RY 2016. (hours)	(Data Validation #9)
If no, have direct measurements been performed on compressor sources for this compressor in the last 5 years? If yes, complete the direct measurements information in Section 3.	(Picklist #2)

3.) Direct Emissions Measurements for Compressor Leaks or Vents- Complete for each compressor for which emissions measurement data are available and are not already reported to the GHGRP.

Compressor Name/ID	(Picklist = Compressor Name/ID)
Source/Vent Description (e.g., list what compressor sources were measured)	
Date of Measurement (mm/dd/yyyy)	(Data Validation #14)
Operating Mode	(Picklist #49)
Measurement Type	(Picklist #50)
Measurement method for as found tests	(Picklist #43)
Is the measurement method prior to or after commingling with non-compressor emission sources?	(Picklist #51)
For continuous measurement, did the measured volume include blowdowns?	(Picklist #2)
Emission Rate	
scf/hr (as found)	(Data Validation #2)
MMScf/yr (continuous)	(Data Validation #2)

4.) Compressor Driver Information - Complete for each compressor driver using best available data.

Compressor Name/ID	
Driver Type	(Picklist #45)
Diesel Engine Tier (40 CFR part 89 and 1039)	(Picklist #47)
Fuel Type	(Picklist #46)
Starter Motor Type	(Picklist #74)
What is the model year of the driver?	(Data Validation #10)
What is the hours of operation of the driver in 2016?	(Data Validation #9)
Are any current environmental regulations applicable to the compressor driver?	(Picklist #2)
Is the compressor driver subject to 40 CFR part 60 subpart IIII?	(Picklist #2)
Is the compressor driver subject to 40 CFR part 60 subpart JJJJ?	(Picklist #2)
Is the compressor driver subject to 40 CFR part 63 subpart ZZZZ?	(Picklist #2)
Is the compressor driver subject to State/Local Environmental Regulations?	(Picklist #2)
What is the primary NOx control used for the compressor driver?	(Picklist #85)

If other, specify	
What is the secondary NOx control used for the compressor driver?	(Picklist #85)
If other, specify	
What PM controls are used for diesel compressor engine? [Diesel engines only]	(Picklist #86)
If other, specify	
Have direct measurements been performed on compressor driver exhaust in the last 5 years?	(Picklist #2)
Attach the most recent source test report and provide file name of the attached report below and summary of results to the right:	
Date of Measurement (mm/dd/yyyy)	(Data Validation #14)
Average fuel feed rate during the source test (MMBtu/hr)	(Data Validation #2)
CO emission rate (lb/hr)	(Data Validation #2)
NOx emission rate (lb/hr)	(Data Validation #2)
VOC emission rate (lb/hr)	(Data Validation #2)
Benzene emission rate (lb/hr)	(Data Validation #2)
Toluene emission rate (lb/hr)	(Data Validation #2)
Ethyl benzene emission rate (lb/hr)	(Data Validation #2)
Xylenes (total) emission rate (lb/hr)	(Data Validation #2)
Formaldehyde emission rate (lb/hr)	(Data Validation #2)
Total HAP emission rate (lb/hr)	(Data Validation #2)
PM emission rate (lb/hr)	(Data Validation #2)
Optional: If you would like to submit additional recent test data:	
Provide file name of "Report 2" that is attached, if applicable:	
Provide file name of "Report 3" that is attached, if applicable:	

5.) Centrifugal Compressor Specific Information - Complete for each Centrifugal Compressor:

Unit Name/ID	
If wet, provide the number of wet seals	(Data Validation #1)
If wet seals were replaced with dry seals on or after 1/1/2010, provide the date of the replacement. (mm/dd/yyyy)	(Data Validation #14)
If wet seals were replaced with dry seals on or after 1/1/2010, provide the total cost (equipment plus installation labor). ($)	(Data Validation #2)

6.) Reciprocating Compressor Specific Information - Complete for each Reciprocating Compressor:

Unit Name/ID	
Date of last rod/rod packing replacement (mm/dd/yyyy)	(Data Validation #14)
Hours of Operation Since Last Rod/Rod Packing Replacement (hrs)	(Data Validation #20)
Total cost of last rod/rod packing replacement ($)	(Data Validation #2)
Frequency of rod/rod packing replacement	(Picklist #52)
If Other, provide rod/rod packing replacement schedule.	

Attachment 3N: Draft Part 2 Questionnaire Blowdown Sheet

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Blowdown Sheet

1.) Facility Information:

Facility ID (pulled from Facility sheet)	
Did the facility blowdown any equipment or piping in 2016?	(Picklist #2)

2.) Blowdown Event Information: Provide the information on the blowdown events that occurred within your facility based on available information. To the extent practical, provide the blowdown information specific to the equipment categories provided. Use the "other equipment" category when equipment specific information is not available.

Category	**Number of Events associated with equipment volumes ≥50 cf**	**Cumulative pre-control volume of natural gas blown down events associated with equipment volumes ≥50 cf (scf)**	**How were blowdown events/volumes associated with equipment volumes ≥50 cf determined?**	**Number of Events associated with equipment volumes <50 cf**
Facility piping (except gathering or transmission pipelines)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Gathering or Transmission Pipeline venting	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Compressors	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Scrubbers/strainers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Pig launchers and receivers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Storage wells/Storage field	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Emergency shutdowns (regardless of equipment)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)
Other equipment not otherwise specified	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)

Attachment 3N: Draft Part 2 Questionnaire Blowdown Sheet

	Cumulative pre-control volume of natural gas blown down events associated with equipment volumes <50 cf (scf)	**How were blowdown events/volumes associated with equipment volumes <50 cf determined?**	**How were blowdown events/volumes associated with equipment volumes <50 cf determined?**	**Were any controls used for blowdown releases?**
Facility piping (except gathering or transmission pipelines)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Gathering or Transmission Pipeline venting	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Compressors	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Scrubbers/strainers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Pig launchers and receivers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Storage wells/Storage field	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Emergency shutdowns (regardless of equipment)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
Other equipment not otherwise specified	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)	(Picklist #2)
If controlled, provide cumulative volume of blowdown gas by control method (scf):				
	Flare	**Flare Control Device ID**	**Thermal oxidizer/ Incinerator**	**Thermal Oxidizer Control Device ID**
Facility piping (except gathering or transmission pipelines)	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Gathering or Transmission Pipeline venting	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Compressors	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Scrubbers/strainers	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Pig launchers and receivers	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)

Storage wells/Storage field	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Emergency shutdowns (regardless of equipment)	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)
Other equipment not otherwise specified	(Data Validation #2)	(Picklist = Control Device ID's)	(Data Validation #2)	(Picklist = Control Device ID's)

If controlled, provide cumulative volume of blowdown gas by control method (scf):

	Used as fuel (heater, boiler, or engine)	**Recovered for sale**	**Other**	**Specify type of "other" control used**	**Other Control Device ID (If applicable)**
Facility piping (except gathering or transmission pipelines)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Gathering or Transmission Pipeline venting	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Compressors	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Scrubbers/strainers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Pig launchers and receivers	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Storage wells/Storage field	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Emergency shutdowns (regardless of equipment)	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)
Other equipment not otherwise specified	(Data Validation #2)	(Data Validation #2)	(Data Validation #2)		Picklist = Control Device ID's)

3.) Blowdown Emissions Reduction Measures: Provide information on additional blowdown emissions reduction measures used at your facility.

Were hot taps or other practices used to reduce/eliminate need for some blowdown events?	(Picklist #2)

Attachment 3N: Draft Part 2 Questionnaire Blowdown Sheet

Type of Practice	Amount of Use		Cumulative volume of blowdown avoided (scf)	
	Value	UOM		
Hot taps	(Data Validation #1)	Number of Events	(Data Validation #2)	
Use pipeline pump down techniques	(Data Validation #1)	Number of Events	(Data Validation #2)	
Recompression with multiple lines	(Data Validation #1)	Number of Events	(Data Validation #2)	
Use mechanical of composite sleeve	(Data Validation #1)	Number of Events	(Data Validation #2)	
Use flexible membrane liners (pipelines)	(Data Validation #1)	Miles of pipeline	(Data Validation #2)	
Inspect/repair leaking (not fully sealed) PRD and blowdown valves	(Picklist #23)	Frequency	(Data Validation #2)	Specify other:
Other (specify)	(Data Validation #1)	Number of Events	(Data Validation #2)	
Other (specify)	(Data Validation #1)	Number of Events	(Data Validation #2)	
Other (specify)	(Data Validation #1)	Number of Events	(Data Validation #2)	
Other (specify)	(Data Validation #1)	Number of Events	(Data Validation #2)	

Part 2 - Oil and Gas Information Collection Request

Detailed Facility Survey: Gathering and Boosting (G&B) Random Facility Selector Tool

Instructions

This information collection request is designed to be completed by operators of gathering and boosting facilities.

Step 1. Please go to "Formulas" in Excel's functional tabs on the ribbon, select "Calculation Options", and select "Manual".

Step 2. Please go the "Parent Company" tab and complete the parent company information requested under Section 1. This information should be for the highest-level, majority corporate owner. See table below Section 1 on small business size standards by primary NAICS code for guidance when responding to the small business question.

Step 3. Please complete the facility-level information requested in "Compression_Fac" sheet for all gathering and boosting compression facilities operating under the parent company. Please refer to the definition of "gathering and boosting compression facility" in the blue Definitions box (to the right of these instructions). If you own/operate more than 1000 facilities, please use the super-sized form.

Step 4. Please complete the facility-level information requested in "Pipeline_Fac" sheet for all gathering and boosting pipeline facilities operating under the parent company. Please refer to the definition of "gathering and boosting pipeline facility" in the blue Definitions box (to the right of these instructions). Please note that the pipeline facility is broken out by county within basins. If you operate in more than 1000 basin/state/counties, please use the super-sized form.

Step 5. Once all facilities have been entered in the "Compression_Fac" and "Pipeline_Fac" sheets, please press "F9" or select "Calculate Now" under the "Formulas" functional tab. Please note that facilities required to respond to Part 2 of the Oil and Gas ICR will now be highlighted in yellow in the "Compression_Fac" and "Pipeline_Fac" sheets. The tables below ("G&B COMPRESSION Facilities Required to Submit Part 2 Survey" and "G&B PIPELINE Facilities Required to Submit Part 2 Survey") will also be populated with required responding facilities.

Step 6. Please save the file and upload it to e-GGRT as part of your Part 2 response.

Definitions

Gathering and Boosting Compression Facility or Gathering and Boosting Compressor Station - Any grouping of equipment under the control of the same person (or persons under common control) at a single surface site that includes a permanent combination of one or more compressors that move natural gas at increased pressure through gathering pipelines.

Gathering and Boosting Pipeline Facility - All natural gas gathering pipelines and associated equipment under the control of the same person (or persons under common control) within a single state, single county, and single hydrocarbon basin within the onshore petroleum and natural gas gathering and boosting industry segment except equipment that is located at a Gathering and Boosting Compression

Facility. Associated equipment includes, but is not limited to, dehydrators, acid gas removal units, pig launchers/receivers, pressure vessels, and storage tanks, and may include equipment at well surface sites if that equipment is owned/operated by the Gathering and Boosting Pipeline Facility.

Gathering pipelines - A network of pipes that are used to convey petroleum and/or natural gas from production facilities to a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting pipeline facility.

Surface site - Any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Basin - Geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7).

G&B COMPRESSION Facilities Required to Submit Part 2 Survey

Facility Name	[These entries will be automatically populated from Table 2 entries]
Assigned Facility ICR ID	[These entries will be automatically populated from Table 2 entries]

G&B PIPELINE Facilities Required to Submit Part 2 Survey

Facility Name	[These entries will be automatically populated from Table 3 entries]
Assigned Facility ICR ID	[These entries will be automatically populated from Table 3 entries]

1. Parent Company General Information

Legal Name:	
Assigned Parent Company ICR ID:	
Does this company meet the definition of small business?	
Dun and Bradstreet Number:	
Mailing Address:	
Mailing City:	
Mailing State:	
Mailing Zip:	
Contact Name:	
Contact Title:	
Contact Phone:	
Contact Phone 2:	
Contact Email:	
Contact Email 2:	

Small Business Size Standards as of February 2016

NAICS Codes	NAICS Industry Description	Small Business Size Standard

211111	Crude Petroleum and Natural Gas Extraction	1,250 employees
211112	Natural Gas Liquid Extraction	750 employees
486110	Pipeline Transportation of Crude Oil	1,500 employees
486210	Pipeline Transportation of Natural Gas	$27.5-million annual receipts

2. Gathering and Boosting Compression Facility General Information – For each gathering and boosting compression facility, provide the following information:

Unique Facility Name	
Operating Company Legal Name	
Basin ID where facility is located	
County and State where facility is located	
Latitude (degrees decimal)	
Longitude (degrees decimal)	

3. Gathering and Boosting Pipeline Facility General Information – For each gathering and boosting pipeline facility, provide the following information:

Unique Facility Name	
Operating Company Legal Name	
Basin ID	
County and State within Basin	

Attachment 4A: Industry Burden and Cost for Responding to the Part 1 Questionnaire

	Hours and Costs Per Respondent/ Activity[1]						Occur-rences/ Respon-dent/ Year[3]	O & M Cost	Number of Respond.[3]	Total Hours and Costs	
	Engineer	Operator	Mgr.[2]	Cler.[2]	Total Respon-dent Hours/ Activity	Total Labor Cost/ Activity				Total Hours/ Year	Total Cost/ Year
	$148.95	$65.10	$176.95	$47.08							
	per hour	per hour	per hour	per hour							
Collection activities											
1.Read instructions	0.5		0.03	0.05	0.58	$81	1	$0	15,000	8,625	1,218,791
2. Compile requested information and complete forms	6		0.30	0.60	6.90	$975	1	$0	15,000	103,500	14,625,495
3. Review compiled information[4]	0.6		0.03	0.06	0.69	$98	1	$0	15,000	10,350	1,462,550
4. Acknowledge and submit information	0.25		0.01	0.03	0.29	$41	1	$1	15,000	4,313	624,396
TOTAL										126,788	$17,931,231

1. Labor rates and associated overhead costs were based on May 2015 raw labor rates for the Mining: Oil and Gas Extraction Sector (NAICS 211000), loaded using a factor of 110%. The resulting loaded of hourly rates are: $176.95 for management personnel, $148.95 for engineering personnel, $65.10 for plant operator personnel, and $47.08 for clerical personnel. These values were taken from the Bureau of Labor Statistics Occupational Employment Statistics Survey Web site and reflect the latest values available (May 2015) and are available at: http://www.bls.gov/oes/current/naics3_211000.htm.

2. Management hours are assumed to be 5 percent of technical (engineering + operator) hours, and clerical hours are assumed to be 10 percent of technical hours.

3. Based on the number of operators identified in the Drilling Information database.

4. Assumed to be 10 percent of the time to compile the information.

Attachment 4B: Industry Burden and Cost for Responding to the Part 2 Questionnaire

	Hours and Costs Per Respondent/ Activity[1]						Occurrences/ Respondent/ Year[3]	O & M Cost	Number of Respond.[4]	Total Hours and Costs	
	Engineer $148.95 per hour	Operator $65.10 per hour	Mgr.[2] $176.95 per hour	Cler.[2] $47.08 per hour	Total Respondent Hours/ Activity	Total Labor Cost/ Activity				Total Hours/ Year	Total Cost/ Year
Collection activities											
1.Read instructions	3		0.15	0.30	3.45	$488	1	$0	4,175	14,404	2,035,381
2. Complete G&B Selection Tool	5		0.25	0.50	5.75	$813	1	$0	800	4,600	650,022
3. Compile requested information and complete forms											
3A. Facility Info	1.5		0.08	0.15	1.73	$244	1	$0	4,175	7,202	1,017,691
3B. Production Wells	3		0.15	0.30	3.45	$488	1	$0	2,350	8,108	1,145,664
3C. Inject/Storage Wells	1		0.05	0.10	1.15	$163	1	$0	1,376	1,582	223,608
3C. Tanks/Separators	2		0.10	0.20	2.30	$325	1	$0	3,610	8,303	1,173,290
3D. Pneumatics	2		0.10	0.20	2.30	$325	1	$0	2,647	6,088	860,304
3E. AGRU	1		0.05	0.10	1.15	$163	1	$0	1,547	1,779	251,396
3F. Dehydrators	1		0.05	0.10	1.15	$163	1	$0	1,788	2,056	290,560
3G. Compressors	2		0.10	0.20	2.30	$325	1	$0	2,248	5,170	730,625
3H. Equipment Leaks	2		0.10	0.20	2.30	$325	1	$0	4,175	9,603	1,356,921
3I. Blowdown Events	1		0.05	0.10	1.15	$163	1	$0	4,175	4,801	678,460
3J. Control Devices	1		0.05	0.10	1.15	$163	1	$0	3,427	3,941	556,906
4. Perform on-site tasks (component counts and feed material sampling)											
4A. Pneumatic counts		4	0.20	0.40	4.60	$315	1	$0	2,647	12,176	832,804
4B. Equipment counts		6	0.30	0.60	6.90	$472	1	$0	5,049	34,838	2,382,790
4C. Tank feed sampling		4	0.20	0.40	4.60	$315	1	$0	2,726	12,540	857,660
5. Feed sample analysis and results review per sample	0.25		0.01	0.03	0.29	$41	2	$1,200	2,726	1,567	6,763,895
6. Review compiled information[5]	3		0.15	0.30	3.45	$488	1	$0	4,175	14,404	2,035,381
7. Submit information	1		0.05	0.10	1.15	$163	1	$0	4,175	4,801	678,460
TOTAL										157,963	$24,521,818

1. Labor rates and associated overhead costs were based on May 2015 raw labor rates for the Mining: Oil and Gas Extraction Sector (NAICS 211000), loaded using a factor of 110%. The resulting loaded of hourly rates are: $176.95 for management personnel, $148.95 for engineering personnel, $65.10 for plant operator personnel, and $47.08 for clerical personnel. These values were taken from the Bureau of Labor Statistics Occupational Employment Statistics Survey Web site and reflect the latest values available (May 2015) and are available at: http://www.bls.gov/oes/current/naics3_211000.htm.

2. Management hours are assumed to be 5 percent of technical (engineering + operator) hours, and clerical hours are assumed to be 10 percent of technical hours.

3. One time survey so most occurrences are 1. Assumed 2 tank feed samples would be taken for analysis from the separators for a typical facility; the cost of each analysis was estimated to be $1,200.

4. Number of respondents are dependent on the industry segment based on the targeted number of respondents and the type of equipment at each facility. All facilities would have to complete the Facility, Equipment Leaks, and Blowdown Event forms and 4,175 total facility respondents are being targeted. There are 800 corporate gathering and boosting facilities in the mailing list. Only production facilities will have production well sites, and there are 2,350 production facility respondents. Storage tanks were estimated to be at every production, gathering and boosting (G&B) compression (GBC), G&B pipeline (GBP), processing, and transmission compression (TC) industry segments (2350+357+357+244+302 =3,610) and pneumatic devices were assumed to be used at 80% of production facilities and 50 percent of GBC, GBP, processing, TC, and transmission pipeline facilities (0.8*2350+0.5*(357+357+244+302+273) =2,647). Acid gas removal units (AGRU) were assumed to be at 50 percent of production, GBC, and processing facilities and 20% of GBP ((2350+357+244)/2+0.2*357)=1,547). Dehydrators are expected to be at every processing plant, 50% of production and GBC, and 20% of GBP, TC, underground storage, and LNG facilities (244+(2350+357)*0.5+(357+302+201+80+11)*0.2=1,788). Compressors were assumed to be at 50% of production facilities and processing plants and at all GBC, TC, underground storage, and LNG facilities (0.5*(2350+244)+357+302 +201+80+11=2,248). Control devices were assumed to be at all production, GBC, and processing facilities and 50% of GBP, TC, underground storage and LNG facilities (2350+357+244+0.5*(357+302+201+80+11)=3,427). The number of respondents for pneumatic counts were assumed to be the same as the respondents completing the pneumatics device tab. For the equipment component counts, counts for GBP, processing and TP facilities were expected to take twice as long as other industry segments, so these segments were counted twice (4,175+357+244+273=5,049). For tank feed sampling and analysis, throughput limits were included in the requirements, so not everyone would require feed analysis; assumed every production, 50% of processing, and 25% of GBC, GBP. And TC facilities would have to take feed samples for flash analysis (2350+0.5*244+0.25*(357+357+302)=2,726).

5. Assumed to be 10 percent of the time to compile the information, which averaged 30 technical hours per respondent.

Attachment 5: Agency Burden and Cost

	Hours and Costs Per Respondent/Activity[1]							Total Hours and Costs		
	Tech. $53.42 per hour	Mgr.[2] $88.30 per hour	Cler.[2] $30.11 per hour	Total Respon. Hours/ Activity	Total Labor Cost/ Activity	Occur-rences/ Respon-dent/ Year	O & M Cost	Number of Respond.	Total Hours/ Year	Total Cost/ Year
Collection activities										
A. Part 1 Questionnaire										
1. Develop Questionnaire	20	1	2	23	$1,217	1	$0	1	23	$1,217
2. Send Questionnaire[3]	0	0	0.05	0.05	$2	1	$5.12	15,000	750	$99,383
3. Key-in hard copy submittals[4]	0	0	1	1	$30	1	$0	3,000	3,000	$90,330
4. Review and Analyze Responses[5]	0.25	0.0125	0.025	0.29	$15	1	$0	15,000	4,313	$228,173
B. Phase 2 Questionnaire				0						
1. Develop Questionnaire	80	4	8	92	$4,868	1	$0	1	92	$4,868
2. Send Questionnaire[3]	0	0	0.05	0.05	$2	1	$6.53	4,656	233	$37,413
3. Review and Analyze Responses[6]	1	0.05	0.1	1.15	$61	1	$0	4,175	4,801	$254,032
C. Respondent Support				0						
1. Answer respondent questions on Part 1[7]	0.25	0.0125	0.025	0.29	$15	1	$0	1,500	431	$22,817
1. Answer respondent questions on Part 2[8]	0.25	0.0125	0.025	0.29	$15	1	$0	4,175	1,200	$63,508
TOTAL									14,843	$801,740

1. Labor rates for EPA personnel were used for all public-sector personnel, including employees of State agencies. Source for EPA labor rates: Department of Personnel Management, "Salary Table 2015-GS," https://www.opm.gov/policy-data-oversight/pay-leave/salaries-wages/salary-tables/pdf/2015/GS_h.pdf. For the managerial labor rate, level GS-15, step 5 was used; for the technical labor rate, level GS-12, step 5 was used; for the clerical labor rate, level GS-7, step 5 was used. All agency labor rates include a multiplier of 1.6 to account for overhead and fringe benefit costs.
2. Management hours are assumed to be 5 percent of technical hours, and clerical hours are assumed to be 10 percent of technical hours.
3. The Agency assumes that only clerical labor will be used to send the letter, and that instructions and a link to the electronic survey will be mailed via USPS using certified mail with electronic return receipt. Part 1 assumed to be 1 oz, small envelope; Part 2 assumed to be 2 oz and use a 9"x12" envelope.
4. Hard-copy submittals are assumed to be entered by clerical staff only. It is assumed that 20 percent of respondents submit hard copy responses.
5. The Agency estimates that it will require 0.25 hours to review and analyze each Part 1 response.
6. The Agency estimates that it will require 1 hour to review and analyze each Part 2 response.
7. The Agency assumes that 10 percent of respondents to Part 1 will have one question. A response to each question is estimated to require 0.25 technical hours, on average.
8. The Agency assumes that the average respondent to Part 2 questionnaire will have one question. A response to each question is estimated to require 0.25 technical hours, on average.