Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

Petroleum Refinery
Emissions Information Collection

General Instructions

NOTE: The final version of this questionnaire will be in electronic format, not in hard copy. The majority of these instructions will be incorporated into the Section 114 letter and available on the website.

Please provide the information requested in Components 1-3 and, if applicable, Component 4 for the facility listed in the Section 114 letter you received in the mail. If you received one Section 114 letter for multiple facilities, you must create a separate survey response for each facility.[1]

Use the 2010 calendar year as the base year for all survey responses (*e.g.*, 2010 emissions inventory, 2010 throughput, 2010 equipment configurations) unless another year is specified in the instructions (*e.g.*, for existing emissions test data).

The following sections (Component 1) are to be completed by all facilities and returned to the address noted below by May 31, 2011:

- Part I – General Facility Information: Provide information on the petroleum refinery at the facility level.
- Part II – Process and Emissions Information: Provide detailed information on the process units and other emissions sources at the petroleum refinery.
- Part III – Incidence Reports: Provide copies of reports filed as a result of specific incidents at the petroleum refinery and information on public complaints.
- Part IV – Cost Information: Provide the age and cost to install and operate control equipment at the petroleum refinery.
- Part V – Emissions Monitoring and Source Test Data: Provide results of all existing emissions data from tests or monitoring conducted on any of the processes or emission points included in Part II, Sections 2 through 17.

The following section (Component 2) is to be completed by all facilities and returned to the address noted below by June 30, 2011:

- Part VI – Emissions Inventory: Provide emissions estimates for the requested process units and other emissions sources at the petroleum refinery.

The following section (Component 3) is to be completed by all facilities and returned to the address noted below by August 31, 2011:

- Part VII – Distillation Feed Composition Analysis: Conduct an analysis of the composition of the feed to each distillation column at the refinery.

[1] For purposes of this information request, "facility" is defined as any stationary source or group of stationary sources located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control.

Component 4 (Part VIII), emissions testing, is to be completed by facilities with process units selected for testing. The Section 114 letter you received directs you to a website where you can find a list that indicates if a unit at your refinery has been selected for testing as well as detailed instructions on how the testing must be conducted. For units requiring stack tests, emissions tests (consisting of three runs per test method required) are to be conducted according to Part VIII for each unit. For fuel gas samples, triplicate grab samples are to be taken for each mix drum associated with a fuel gas system. Follow the instructions in Part VIII for sampling the wastewater treatment system. The results of the emissions tests and other requested analyses should be returned to EPA by August 31, 2011.

The electronic version of the survey (Parts I, II, III, and IV of this Component 1) can be downloaded from the ICR website (https://refineryicr.rti.org). Detailed instructions for each part follow. **NOTE: The final version of this questionnaire will be in electronic format, not in hard copy. The questions are provided in this document merely for convenience during the public comment period.**

If you are unable to respond to an item exactly as requested, please explain why you cannot respond and/or provide any information you believe may be related. For example, if you have a special or unique type of process unit and the questions in the section related to that process unit are not relevant to your specific unit, please provide information that would help EPA classify your process unit and account for its existence and operation in potential future rulemaking.

Questions regarding this information request should be directed to Ms. Brenda Shine at (919) 541-3608 or shine.brenda@epa.gov.

Confidential Business Information (CBI)

If you believe that providing any specific information to us would reveal a trade secret, or would compromise confidential business information (CBI), please identify this information clearly in your response and submit your response as detailed in the next section. Also, please clearly label any flow diagrams or other attachments submitted with your survey that contain CBI. However, please do not label your entire response as CBI if only a portion includes trade secrets.

The EPA's procedures for handling CBI are described in the letter (and enclosures) accompanying this questionnaire. The EPA is likely to follow-up with a request for validation of CBI claims for facilities claiming large amounts of information as trade secret, especially information that is readily reported by other facilities without such claims. Any information EPA subsequently determines to constitute CBI or a trade secret under EPA's CBI regulations at 40 CFR part 2, subpart B, will be protected pursuant to those regulations and, for trade secrets, under 18 U.S.C. 1905. If no claim of confidentiality accompanies the information when it is received by EPA, it may be made available to the public by EPA without further notice pursuant to EPA regulations at 40 CFR 2.203. Because Clean Air Act (CAA) section 114(c) exempts emission data from claims of confidentiality, the emission data you provide will be made available to the public notwithstanding any claims of confidentiality.

How to Submit Your Survey Response

If your response to this information collection request includes data with a claim of CBI, you should follow the instructions in this section to ensure the protection of your data. Please note that if you submit CBI, you should separate your data into two packages, one containing your entire response, including any information claimed as CBI, and the other containing only information that you do not claim as CBI (hereafter referred to as "non-CBI"). These two packages should be sent to EPA separately, using two different mailing addresses.

Separating CBI and Non-CBI

As you complete and review your survey response, identify the information you consider CBI. Clearly mark the CBI components as "Confidential" in your electronic survey response. If you are sending attachments, clearly mark the CBI portions of the diagrams/pages (*e.g.*, highlight or circle) as such.

Once you have marked the CBI, create a new survey response file that does not include this information. If you have attachments, remove the pages that contain CBI. The resulting files and attachments comprise your non-CBI survey response. Please check carefully to ensure that there is no CBI in these files. Send these files to EPA using one of the methods described under "Submitting Your Non-CBI Response."

Create a separate CD or DVD containing your entire survey response, including CBI. Include on the disk any pages of attachments to your survey response containing CBI, with the CBI portions of the diagrams/pages clearly marked (*e.g.*, highlighted or circled). Clearly mark the disk with the words "Confidential Business Information." Send only these CBI files under separate cover to the address provided under "Submitting CBI."

Submitting Your Non-CBI Response

For the non-CBI portions of your survey response, including non-CBI attachments (and for survey responses that are entirely non-CBI), use one of the following methods to submit your survey response to EPA:

- Upload your files to the ICR website. Detailed directions for uploading your files are provided on the ICR website (https://refineryicr.rti.org).
- E-mail an electronic copy of all requested files to refineryicr@epa.gov.
- Mail a CD or DVD containing an electronic copy of all requested files to the EPA address shown below. If no electronic copy is available, mail a hard copy of all requested files to the address shown below:

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
U.S. EPA Mailroom (D205-01)
Attention: Brenda Shine, Petroleum Refinery Sector Lead
109 T.W. Alexander Drive
Research Triangle Park, NC 27711

EPA recommends sending your non-CBI files via Registered U.S. Mail using return receipt requested, Federal Express, or other method for which someone must provide a signature upon receipt.

Submitting CBI

Follow the instructions under “Separating CBI and Non-CBI” to create the portion of your survey response that contains CBI. Send only these CBI files under separate cover to:

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
U.S. EPA Mailroom (C404-02)
Attn: Mr. Roberto Morales, Document Control Officer
109 T.W. Alexander Drive
Research Triangle Park, NC 27711

For security purposes, EPA highly recommends sending your confidential files to Mr. Morales via Registered U.S. Mail using return receipt requested, Federal Express, or other method for which someone must provide a signature upon receipt.

DO NOT ELECTRONICALLY TRANSMIT CONFIDENTIAL BUSINESS INFORMATION TO EPA. E-mail and facsimile are not secure forms of communication and should never be used to transmit CBI.

ABBREVIATIONS

20 lb/ton coke burn-off	SO_2 emissions limit in 40 CFR part 60, subpart J, of 9.8 kg/Mg (20 lb/ton) coke burn-off (40 CFR 60.104(b)(2))
50/25 ppmv SO_2 limit	SO_2 emissions limit in 40 CFR part 60, subpart Ja of 50 ppmv SO_2, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis (40 CFR 60.102a(b)(3))
acfm	actual cubic feet per minute
APCD	air pollution control device
As	arsenic
ASTM	American Society of Testing and Materials
bbl	barrels
bbl/cd	barrels per calendar day
bbl/sd	barrels per stream day
bbl/yr	barrels per year
BOD	biological oxygen demand
BQ	benzene quantity
Btu/lb	British thermal units per pound
BWON	Benzene Waste Operations NESHAP (40 CFR part 61, subpart FF)
CAA	Clean Air Act
CAS	Chemical Abstracts Service
CBI	confidential business information
CCU	catalytic cracking unit
CEMS	continuous emission monitoring system
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CO	carbon monoxide
COD	chemical oxygen demand
COS	carbonyl sulfide
CRU	catalytic reforming unit
DCU	delayed coking unit
DIAL	Differential Absorption Light Detection and Ranging
DMEA	dimethylethanolamine
E-cat	equilibrium catalyst
EPA	U.S. Environmental Protection Agency

ESP	electrostatic precipitators
ETBE	ethyl tert-butyl ether
F/M ratio	food to microorganism ratio
FCU	fluid coking unit
ft	feet
gal/day	gallons per day
gal/min	gallons per minute
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HAP	hazardous air pollutants
HF	hydrogen fluoride
Hg	mercury
hr	hours
hr/yr	hours per year
ICR	information collection request
ID	identification number or code
Iso C5,C6	isopentane (aka 2-methylbutane), isohexane (aka 2-methylpentane)
Lat/Long	latitude and longitude
lb/ft^3	pounds per cubic foot
lb/hr	pounds per hour
lb/ton	pounds per ton
LDAR	leak detection and repair
LPG	liquefied petroleum gas
LT/cd	long tons per calendar day
MACT	Maximum Achievable Control Technology
MCRC	maximum Claus recovery/conversion
Mg/yr	megagrams per year
MLSS	mixed liquor suspended solids
MLVSS	mixed liquor volatile suspended solids
MM lb	million pounds
MMBtu/hr	million British thermal units per hour
MMcf	million cubic feet
MMcf/cd	million cubic feet per calendar day
MMgal/day	million gallons per day
MTBE	methyl tert-butyl ether
MW	megawatts
MWh	megawatt-hours

NAD	North American Datum
NESHAP	national emissions standards for hazardous air pollutants
Ni	nickel
No.	number
NO_X	oxides of nitrogen
NSPS	new source performance standards
OVA	organic vapor analyzer
PM	particulate matter
ppmv	parts per million by volume
ppmw	parts per million by weight
PSA	pressure swing absorption
PRD	pressure relief device
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
QA	quality assurance
QC	quality control
regen.	regeneration
SCC	Source Classification Code
scfm	standard cubic feet per minute
SCOT	Shell Claus Off-gas Treating
SCR	selective catalytic reduction
Se	selenium
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SOF	Solar Occultation Flux
SRU	sulfur recovery unit
STERPP	storage tank emission reduction partnership program (72 FR 19891)
TAB	total annual benzene
TAME	tert-amyl methyl ether
THC	total hydrocarbons
TOC	total organic compounds
tons/cd	tons per calendar day
tons/yr	tons per year
TRS	total reduced sulfur
U.S. DOE/EIA	U.S. Department of Energy, Energy Information Administration
ULNB	ultra low NO_X burner (high fraction staged fuel)

UV	ultraviolet
VOC	volatile organic compounds
wt%	weight percent
WWTS	wastewater collection and treatment system
WWTU	wastewater collection or treatment unit
°F	degrees Fahrenheit
%	percent

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PART I: GENERAL FACILITY INFORMATION

1. Facility ID number (EPA will provide this number): ______________________

2a. Plant Name (as reported on U.S. DOE/EIA Form-820 (2010), "Annual Refinery Report," schedule 2, line 1, page 37, question 1):

____

____

____

2b. Does this facility[2] report in EIA-820 the combined processing/production capacities for refining plants that are not contiguously located? **Yes** **No**

2c. If **Yes**, provide the facility ID for each non-contiguous facility: ______________________

____

____

3. Complete street address of facility (physical location): ______________________

____

____

4. Provide mailing address if different: ______________________

____

____

5. Name and title of contact(s) able to answer technical questions about the completed survey: ______________________

____

6. Contact(s) telephone number(s): ______________________

and e-mail address(es): ______________________

7. Name of legal owner of facility: ______________________

____

____

____

8. Name of legal operator of facility, if different from legal owner: ______________________

____

____

[2] For purposes of this information request, "facility" is defined as any stationary source or group of stationary sources located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control.

9. Address of ____ legal owner or ____ operator: ____
____
____
____

10. Dunn and Bradstreet number of your facility: ____

11. Annual revenue in 2010: $______________________

12. Number of employees at your facility: ____

13a. Are you part of a larger corporate entity or joint venture? **Yes** **No**

13b. If 13a is **Yes**, is the facility operated under a joint venture partnership? **Yes** **No**

If **Yes**: Provide the name and % ownership of each joint venture partner and provide the number of employees for each joint venture partner with 50% or greater ownership:

Partner name ______________ Percent ownership ______% No. employees ______
Partner name ______________ Percent ownership ______% No. employees ______
Partner name ______________ Percent ownership ______%

If **No**: Name of parent company: ____

Number of employees in parent company: ____________________________

Check the statement below that best applies:

____ The facility is fully independent of the parent organization (independent sources of capital, different Boards of Directors, etc.).

____ The parent organization provides some financial support.

____ Operations of the parent organization and this facility are fully integrated (full access to investment capital, same Board of Directors, etc.)

14. Circle all the applicable code numbers that describe the type of refinery:

1 Topping refinery
2 Hydroskimming refinery
3 Upgrading refinery
4 Heavy oil/asphalt refinery

15. Provide the quantity of products produced at the refinery and their relative disposition (transport method) in 2010. Production values should be provided as reported to EIA on form EIA-810 form, except specify aromatics production quantities. Provide the relative disposition of products from readily available information; exact quantity information is not necessary. For products piped directly to an offsite marine vessel tank ship terminal or tank truck terminal that is located near the refinery and is owned, operated, or under common control of the refinery (or its corporate holdings), report the transportation method as tank ship or tank truck, respectively, rather than reporting this quantity as "% shipped by pipeline." Report under "% shipped by pipeline" all products shipped via general use pipelines (regardless of secondary transportation methods that may be served) or products piped directly to other offsite facilities.

Product/Refinery Output	Cumulative 2010 Production (1,000 bbls)	Disposition of Products by Transport Method					
		% used onsite	% shipped by tank ship	% shipped by barge	% shipped by tank truck	% shipped by rail car	% shipped by pipeline
Ethane							
Ethylene							
Propane							
Propylene							
Normal Butane							
Butylene							
Isobutane							
Isobutylene							
Unfinished Oils – Naphthas and lighter							
Unfinished Oils – Kerosene and light gas oils							
Unfinished Oils – Heavy gas oils							
Unfinished Oils – Residuum							
Finished Motor Gasoline - Reformulated							
Finished Motor Gasoline - Conventional							
Motor Gasoline Blending Components - Reformulated							
Motor Gasoline Blending Components - Conventional							
Aviation Gasoline – Finished and Blending Components							
Special Naphthas (solvents)							
Kerosene-type Jet Fuel							
Kerosene							

Product/Refinery Output	Cumulative 2010 Production (1,000 bbls)	Disposition of Products by Transport Method					
		% used onsite	% shipped by tank ship	% shipped by barge	% shipped by tank truck	% shipped by rail car	% shipped by pipeline
Distillate Fuel Oil – 15 ppm sulfur and under							
Distillate Fuel Oil – greater than 15 ppm to 500 ppm sulfur							
Distillate Fuel Oil – greater than 500 ppm sulfur							
Residual Fuel Oil – less than 0.31% sulfur							
Residual Fuel Oil – 0.31% to 1.0% sulfur							
Residual Fuel Oil – greater than 1% sulfur							
Lubricants (total)							
Asphalt and Road Oil							
Wax							
Petroleum Coke – Marketable							
Petroleum Coke – Catalyst							
Still Gas							
Petrochemical Feedstocks – Naphtha <401°F end-point							
Petrochemical Feedstocks - Other Oils ≥401°F end-point							
Aromatics – Benzene							
Aromatics – Toluene							
Aromatics – Xylenes (total)							
Aromatics – Other than BTX							
Other Miscellaneous Products							

16. Report the 2010 process capacities and actual throughput for each process unit by completing the table below. See definitions section for additional descriptions of the terms used. You may need to add "other" process units if your refinery contains significant processing units that are not covered by the processes listed. If 2010 throughputs are not representative of normal operations (*e.g.*, plant idled temporarily for economic reasons, change of ownership, or fire, etc.), add a note describing the reason for the unusual operation and provide an estimate of the expected "normal" 2010 processing rates had these issues not occurred.

When asked for a Unit ID, please use the same identifying number or code that is used in EPA's 2005 National Scale Air Toxics Assessment (NATA) National Emissions Inventory (NEI) data set (if possible and/or applicable). Instructions for locating the NEI data set for your refinery are located at the ICR website (https://refineryicr.rti.org). If the NEI does not show an entry for a particular unit, or you are not sure what units are included in the NEI data set, use a unique Unit ID for each process unit.

Provide the coordinates (latitude and longitude) of the approximate process unit centroid in North American Datum (NAD) 83 with 6 digits to the right of the decimal point.[3] (If currently available coordinates have five digits to the right of the decimal point instead of six, those coordinates are acceptable.).

[3]Latitude measure in decimal degrees of the angular distance on a meridian north or south of the equator. Positive (+) data point for North America. Example: +78.123456. For point sources, this represents the center of the source; for fugitive sources, this is the southwest corner if the fugitive angle is zero or the western most corner if the fugitive angle is greater than zero. Longitude measure in decimal degrees of the angular distance on a meridian east or west of the prime meridian. Negative (-) data point for North America. Example: -123.234561. For point sources this represents the center of the source; for fugitive sources, this is the southwest corner if the fugitive angle is zero, or the western most corner if the fugitive angle is greater than zero.

Unit ID	Process Type[1]	Unit Throughput Capacity (bbl/cd)[2]	Unit Actual Throughput (bbl/cd)[2]	Unit Latitude	Unit Longitude

[1] See list following the last footnote for codes corresponding to unit types. If none of the codes describe your process, enter "99" and specify the type of process.

[2] Throughput by calendar day × 365 days = annual throughput for 2010.Throughput units are barrels per calendar day (bbl/cd) unless noted otherwise.

For crude distillation through desulfurization units (process type codes 1 through 21), "throughput" is determined in terms of charged liquid material (excluding hydrogen gas inputs).

For catalytic cracking units, include both fresh and recycle feed.

For alkylation through coke calcining (process type codes 22 through 43), "throughput" is determined in terms of primary product produced (*e.g.*, quantity of alkylate produced in alkylation unit).

For aromatics production, report the total quantity of all aromatics produced from various separation processes after catalytic reforming.

For hydrogen production, throughput units are million standard cubic feet per calendar day (MMcf/cd); use 32°F (0°C) and 1 atmosphere as "standard conditions" for H_2 production.

For sulfur recovery, throughput units are long tons per calendar day (LT/cd). 1 LT = 1.12 short tons. Enter individual SRU trains in this table; you will be asked to identify the sulfur recovery plant for each train in Part II, Section 9.

For loading operations, "throughput" is the quantity of material loaded.

For fuel gas treatment, "throughput" is the quantity of fuel gas input to the unit. Throughput units are million standard cubic feet per calendar day (MMcf/cd); use 60°F (15.56°C) and 1 atmosphere as "standard conditions" for fuel gas treatment.

For fuel blending, "throughput" is the quantity of blended product produced.

For wastewater treatment, throughput units are million gallons per day (MMgal/day). If desired, you may report wastewater treatment units used to comply with Benzene Waste Operations NESHAP (40 CFR part 61, subpart FF) "BWON" or sour water treatment units as separate wastewater treatment systems, but you are not required to do so.

Code No.	Type of Process
1	Atmospheric crude distillation
2	Vacuum distillation
3	Delayed coking
4	Fluid coking (traditional)
5	Flexicoking
6	Visbreaking, other thermal cracking
7	Fluid catalytic cracking unit
8	Non-fluid catalytic cracking unit
9	Catalytic hydrocracking
10	Catalytic reforming unit – continuous regeneration
11	Catalytic reforming unit – cyclic regeneration
12	Catalytic reforming unit – semi-regenerative
13	Fuels solvent deasphalting
14	Desulfurization/ hydrotreat – naphtha/reformer feed
15	Desulfurization/ hydrotreat – gasoline
16	Desulfurization/ hydrotreat – kerosene/jet fuel
17	Desulfurization/ hydrotreat – diesel
18	Desulfurization/ hydrotreat – other distillate
19	Desulfurization/ hydrotreat – residual
20	Desulfurization/ hydrotreat – heavy gas oil
21	Desulfurization/ hydrotreat – other
22	HF alkylation
23	H_2SO_4 alkylation
24	Aromatics production
25	Asphalt production
26	Isomerization – Isobutane
27	Isomerization – Iso C5,C6
28	Lubricants production
29	Petroleum coke storage
30	Hydrogen plant
31	Sulfur recovery unit (SRU)
32	Gas plant/light ends distillation/LPG production unit
33	Oxygenate plant – MTBE
34	Oxygenate plant – ETBE
35	Oxygenate plant – TAME
36	Oxygenate plant – other (specify)
37	Ethylene production
38	Ethylene dichloride production
39	Ethylene dibromide production
40	Propylene production
41	Acrylonitrile production
42	Other petrochemical or organic chemical production (specify chemical)
43	Coke calcining
44	Marine vessel loading/unloading
45	Truck/tank truck loading/unloading
46	Rail car loading/unloading
47	Container/other loading/unloading
48	Fuel gas treatment
49	Fuel blending
50	Wastewater treatment system
99	Other (specify)

PART II: PROCESS AND EMISSIONS INFORMATION

When asked for a Unit ID in any section of Part II, please use the same identifying number or code that is used in Part I, Question 16.

SECTION 1. ENERGY MANAGEMENT

1. Facility ID number (EPA will provide this number): ________________________

2. Complete Table 1-1 below to provide the total energy use and fuel consumption by the entire refinery in 2010 (as reported to EIA on forms EIA-810 and EIA-820):

TABLE 1-1. 2010 Fuel Consumption

Fuel	Units	Fuel Consumption
Crude Oil[1]	bbl	
LPG	bbl	
Distillate Fuel Oil	bbl	
Residual Fuel Oil	bbl	
Still Gas	bbl	
Marketable Coke	bbl	
Catalyst Coke	bbl	
Natural Gas	MMcf	
Coal	Tons (US)	
Purchased Electricity	MWh	
Purchased Steam	MM lb	
Other (solid)	Tons (US)	
Other (liquid)	bbl	
Other (gas)	MMcf	

Abbreviations: bbl = barrels
MMcf = million cubic feet at 60°F and 1 atmosphere
MWh = Megawatt-hours
MM lb = million pounds

[1] Report only the quantity of crude oil consumed as fuel, not the quantity of crude oil fed to the atmospheric crude or vacuum distillation column.

3. Report the total quantity of hydrogen purchased [in million cubic feet at 32°F (0°C) and 1 atmosphere] from off-site (merchant) hydrogen producers. Do not include captive hydrogen production included in Part I; more detail regarding captive hydrogen production units is requested in Part II, Section 10.

4. Does this refinery have a facility energy management plan? **Yes** **No**

   If **Yes**: Provide a brief description of the key elements of the plan and key energy reductions that have resulted from the implementation of the plan.

5. Does this refinery generate electricity or steam on-site? **Yes** **No**

If **Yes**: Provide the information requested in Table 1-2 for each electricity-generating, steam generating, or combined heat and power unit. Include energy recovery turbines and waste heat boilers used on process unit exhaust lines.

TABLE 1-2. Electricity and Steam Generation Information

Generation Unit ID	Unit Description[1]	Primary Fuel[2]	Secondary Fuel[2]	Energy Efficiency Measures[3]	Air preheat use[4]	Typical air preheat temperature when used (°F)	Is this unit a combined heat and power unit? (Y/N)	Electricity Generation		Steam Generation				
								Capacity of Unit (MW)	Disposition of electricity[5]	Boiler Heat Input Capacity (MMBtu/hr)	Steam Generating Capacity (lb/hr)	Pressure of Steam (psia)	Disposition of steam[6]	Percent Steam to Blowdown[7]

Footnotes for Table 1-2:

Abbreviations: MW = megawatts

MMBtu/hr = million British thermal units per hour

lb/hr = pounds per hour

psia = pounds per square inch absolute

[1] For waste heat boiler, list process unit and "waste heat boiler" (*e.g.*, "FCCU waste heat boiler").

[2] Select from the following list of fuels.

Code No.	**Type of Fuel**
1	Natural gas
2	Refinery fuel gas (mixture of natural gas and still gas or process gas)
3	Still gas or process gas only (not mixed with natural gas)
4	Distillate fuel oil
5	Heavy gas oil
6	Low Btu fuel gas from flexicoking unit or other gasification process
7	Coal
8	Wood or other biomass fuel
99	Other (specify)

[3] Select the energy efficiency measure(s) used with this unit from the following list. Select all that apply.

Code No.	**Type of Energy Efficiency Measure**
0	None
1	Insulation on boiler
2	Insulation on distribution lines
3	Oxygen monitors used to control/limit excess oxygen
4	Intake air monitors to optimize fuel/air mixtures
5	Combustion air preheat from flue gas
6	Boiler feed water preheat from flue gas
7	Blowdown steam recovery system for low pressure needs
8	Steam trap maintenance
9	Steam condensate return lines (to return condensate (hot water) to boiler)
10	Steam expansion turbines (to recover energy from high pressure steam when steam is needed at lower pressures)
11	Boiler maintenance program to reduce scaling (other than soot blowing)
12	Boiler maintenance program to maintain burners (other than soot blowing)
99	Other (specify)

[4] Select from the following list of air preheat descriptions the option that best applies for the unit.

Code No.	**Type of Air Preheat**
0	No air preheater is present
1	Air preheater is present, but use less than 20% of the time
2	Air preheater is present and used 20% to 50% of the time
3	Air preheater is present and used more than 50% but less than 90% of the time
4	Air preheater is present and used 90% or more of the time

[5] Select from the following list of dispositions.

Code No.	**Type of Electricity Disposition**
1	Generated electricity is used only on-site
2	Generated electricity is used only off-site (*e.g.*, sent to grid)
3	Generated electricity is used on-site with excess used off-site or sent to grid

[6] Select from the following list of dispositions.

Code No.	Type of Steam Disposition
1	Generated steam is used only on-site.
2	Generated steam is used only off-site.
3	Generated steam is used on-site with excess used off-site.

[7] If the exact percentage is unknown, and you are unable to provide a reasonable estimate, answer “Unknown.”

6. Provide the information requested in Table 1-3 for each processing unit listed in Question 16 of Part I (except wastewater treatment systems, which are reported in Section 15).

TABLE 1-3. Steam Demand by Process Unit

Unit ID	Average steam demand for the processing unit during normal operation assuming the processing unit is operated at maximum capacity (lb/hr)[1]

[1] For cyclic processes, such as delayed coking unit, estimate the total steam use over a complete cycle and divide by the cycle time indicative of maximum processing rates.

SECTION 2. PROCESS HEATER DATA

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide the information requested in Table 2-1 for each process heater at the facility that serves a process unit identified in Part I, Question 16.

TABLE 2-1. Process Heater General Information

Process Heater ID	Unit ID for process unit served by process heater	Process heater construction type[1]	Process heater draft type[2]	Is the process heater designed to be e co-fired? (Yes/No)	Rated heat input capacity	Average heat input rate in 2010 (MMBtu/hr)	Total operating hours in 2010 (hr)	Air preheat use[3]	Typical air preheat temperature when used (°F)	Other energy efficiency measures[4]	Primary fuel[5]	Percent of total operating hours process heater fired with primary fuel in 2010	Secondary fuel[5]	Percent of total operating hours process heater fired with secondary fuel in 2010	Operating hours in turndown in 2010 (hr)	Applicable Federal air regulation(s)[6]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Type of PM controls[7]	Type of SO_2 controls[8]	Type of NO_X controls[9]

Footnotes for Table 2-1:

[1] Select from the following list of process heater construction types.

Code No.	Type of Construction
1	Vertical cylinder
2	Cabin or box
99	Other (specify)

[2] Select from the following list of process heater draft types.

Code No.	Type of Draft
1	Natural draft
2	Induced draft (exhaust-side fan only), upward firing
3	Induced draft (exhaust-side fan only), downward firing
4	Forced draft (combustion air-side fan only)
5	Balanced draft (both air- and exhaust-side fans), but no air preheater
6	Balanced draft (both air- and exhaust-side fans) with air preheater
99	Other (specify)

[3] For air preheat use, enter the appropriate code number the option that best describes the air preheat use:

Code No.	Type of Air Preheat
0	No air preheater is present
1	Air preheater is present, but use less than 20% of the time
2	Air preheater is present and used 20% to 50% of the time
3	Air preheater is present and used more than 50% but less than 90% of the time
4	Air preheater is present and used 90% or more of the time

[4] Select from the following list of energy efficiency measures (other than air preheat).

Code No.	Type of Energy Efficiency Measure
0	None
1	Oxygen monitors used to control/limit excess oxygen
2	Intake air monitors to optimize fuel/air mixtures
3	Maintenance program to reduce scaling (other than soot blowing)
4	Maintenance program to maintain burners (other than soot blowing)
5	Finned or dimpled tubes to increase heat transfer
99	Other (specify)

[5] Select from the following list of fuels.

Code No.	Fuel Type
1	Natural gas
2	Refinery fuel gas (mixture of natural gas and still gas or process gas)
3	Still gas or process gas only (not mixed with natural gas)
4	Distillate fuel oil
5	Heavy gas oil
6	Low Btu fuel gas from flexicoking unit or other gasification process
99	Other (specify)

[6] Select the Federal air regulation(s) to which the process heater is subject from the following list of regulations. Select all that apply, but include only regulations to which the process heater is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the process heater is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery NSPS (40 CFR part 60, subpart J)
2	Refinery NSPS (40 CFR part 60, subpart Ja)
3	CAA section 112(g) and section 112(j) (40 CFR part 63, subpart B)
99	Other (specify)

[7] Select from the following list of PM controls; list all that apply.

Code No.	Type of PM Control
0	None
11	Fabric/cartridge filter ("baghouse")
12	Venturi/wet scrubber
13	Electrostatic precipitator (ESP)
14	Wet ESP
96	Management practice or work practice to reduce PM (specify)
99	Other (specify)

[8] Select from the following list of SO_2 controls; list all that apply.

Code No.	Type of SO_2 Control
0	None
21	H_2S limit in fuel gas
22	TRS limit in fuel gas
23	Low sulfur distillate or low sulfur heavy gas oil
24	Wet scrubber/flue gas desulfurization
25	Spray dryer absorber
97	Management practice or work practice to reduce SO_2 (specify)
99	Other (specify)

[9] Select from the following list of NO_X controls; list all that apply.

Code No.	**Type of NO_X Control**
0	None
31	(External) flue gas recirculation
32	Staged air low NO_X burner
33	Staged fuel low NO_X burner
34	Ultra low NO_X burner (high fraction staged fuel) (ULNB)
35	"Next generation" low NO_X burner (ULNB with internal gas recirculation)
36	Selective non-catalytic reduction (SNCR)
37	Selective catalytic reduction (SCR)
98	Management practice or work practice to reduce NO_X (specify)
99	Other (specify)

SECTION 3. EQUIPMENT LEAKS

1. Facility ID number (EPA will provide this number): ______________________

2. Do you own or have ready access to an optical or thermal imaging device for detecting equipment leaks? **Yes** **No**

   If **Yes**:

   a. Provide the manufacturer and model number: ____________________________

   b. How do you most often use the imaging device to detect equipment leaks?

      1 To comply with the alternative work practice for monitoring equipment for leaks (40 CFR 63.11(c) and 40 CFR 60.18(g))
      2 To check for leaks on a fairly routine basis (*e.g.*, leaks that Method 21 monitoring may have missed, leaks from equipment not required to be monitored)
      3 To find leaks following non-routine operations (*e.g.*, pressure integrity checks prior to startup)

3. Complete Table 3-1 for each process unit listed in Part I, Question 16 (except wastewater treatment). The total equipment counts should be the total number of pieces of equipment in a process unit, not necessarily only those currently being monitored. Do not count pieces of equipment that are in vacuum service. You may provide reasonable estimates of equipment counts from existing information if the requested equipment counts are not directly available as requested in Table 3-1 for each process unit as defined in this ICR.

TABLE 3-1. Equipment and Leak Detection Information for Process Units

Unit ID	Applicable Federal air	If subject to State, local, or Tribal air regulation(s), provide the	Average methane concentration in process fluid that contacts equipment in gas service throughout the process	Is the average methane concentration based on sampling and analysis results or estimated (e.g., based on process	For each of the following types of equipment, provide:	Pumps		Valves			Flanges			Connectors			Open-ended lines[3]	Compressors	Hatches	Sight glasses	Gages	Diaphragms	Other[4]
						Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]							
					Number of Pieces of Equipment																		
					Number of Pieces of Equipment Monitored[5]																		
					Monitoring Frequency[6]																		
					Leak Definition (ppmv)[7]																		
					Number of Pieces of Equipment																		
					Number of Pieces of Equipment Monitored[5]																		
					Monitoring Frequency[6]																		
					Leak Definition (ppmv)[7]																		

Footnotes for Table 3-1:

[1] Select the Federal air regulation(s) to which the process unit is subject from the following list of regulations. Select all that apply, but include only regulations for equipment leaks to which the process unit is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the process unit is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	NSPS for Equipment Leaks at Petroleum Refineries (40 CFR part 60, subpart GGG)
4	NSPS for Equipment Leaks at Petroleum Refineries (40 CFR part 60, subpart GGGa)
5	NSPS for Equipment Leaks at SOCMI (40 CFR part 60, subpart VV)
6	NSPS for Equipment Leaks at SOCMI (40 CFR part 60, subpart VVa)
7	HON (40 CFR part 63, subpart H) existing source requirements
8	HON (40 CFR part 63, subpart H) new source requirements
9	MON (40 CFR part 63, subpart FFFF) existing source requirements
10	MON (40 CFR part 63, subpart FFFF) new source requirements
11	Gasoline Distribution (40 CFR part 63, subpart R) existing source requirements
12	Gasoline Distribution (40 CFR part 63, subpart R) new source requirements
13	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) existing source requirements
14	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) new source requirements
99	Other (specify)

[2] Use the definitions of "gas service," "light liquid service," and "heavy liquid service" in the regulation to which your process unit is subject, if applicable. See the list of definitions for this ICR for definitions of these terms to use if your process unit is not subject to a regulation that includes definitions of these terms.

[3] The information requested for open-ended lines refers to leakage from the open-end of a pipe or valve and not to leakage from the associated valve packing or body flanges.

[4] Other equipment includes any other fugitive emissions source not already provided that is monitored similar to equipment. Specify the types of fugitive emission sources.

[5] Do not include difficult-to-monitor equipment in this count.

[6] Select from the following list of monitoring frequencies the option that best describes the frequency at which the majority of the equipment are monitored for the process unit, type of equipment, and type of service. (For "other," if you specified multiple types of fugitive emission sources and they have different monitoring frequencies, select the shortest monitoring interval for such sources.)

Code No.	Monitoring Frequency
0	None (unit/system not monitored for leaks)
1	No set interval (use only for sensory monitoring)
2	Less than annually
3	Annually
4	Semiannually
5	Quarterly
6	Monthly
7	Biweekly
8	Weekly or more frequently

[7] Select from the following list of leak definitions the monitored concentration above which repairs are required (or routinely performed) for the process unit, type of equipment, and type of service. (For "other," if you specified multiple types of fugitive emission sources and they have different leak definitions, select the lowest leak definition for such sources.)

Code No.	Leak Definition
0	None (unit/system not monitored for leaks)
1	Detection by sensory monitoring
2	10,000 ppmv
3	5,000 ppmv
4	2,000 ppmv
5	1,000 ppmv
6	500 ppmv
7	Less than 500 ppmv

4. Complete Table 3-2 for each fuel gas and natural gas system at the facility. The equipment counts should be the total number of pieces of equipment the fuel gas and natural gas system at the facility (without double counting equipment included in Table 3-1). You may provide reasonable estimates of equipment counts from existing information if the requested equipment counts are not directly available as requested for each fuel gas and natural gas system.

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

TABLE 3-2. Equipment and Leak Detection Information for Fuel Gas and Natural Gas Systems

Unit ID	Applicable Federal air	If subject to State, local, or Tribal air regulation(s), provide the	Average methane concentration in process fluid that contacts equipment in gas service throughout the process	Is the average methane concentration based on sampling and analysis results or estimated (e.g.. based on process	For each of the following types of equipment, provide:	Pumps		Valves			Flanges			Connectors			Open-ended lines[3]	Compressors	Hatches	Sight glasses	Gages	Diaphragms	Other[4]
						Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]	Gas[2]	Light liquid[2]	Heavy liquid[2]							
					Number of Pieces of Equipment																		
					Number of Pieces of Equipment Monitored[5]																		
					Monitoring Frequency[6]																		
					Leak Definition (ppmv)[7]																		
					Number of Pieces of Equipment																		
					Number of Pieces of Equipment Monitored[5]																		
					Monitoring Frequency[6]																		
					Leak Definition (ppmv)[7]																		

Footnotes for Table 3-2:

[1] Select the Federal air regulation to which the fuel gas or natural gas system is subject from the following list of regulations. Select all that apply, but include only regulations for equipment leaks to which the fuel gas or natural gas system is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the fuel gas or natural gas system is subject).

Code No.	Federal Air Regulation
0	None
1	NSPS for Equipment Leaks at Petroleum Refineries (40 CFR part 60, subpart GGG)
2	NSPS for Equipment Leaks at Petroleum Refineries (40 CFR part 60, subpart GGGa)
3	NSPS for Equipment Leaks at SOCMI (40 CFR part 60, subpart VV)
4	NSPS for Equipment Leaks at SOCMI (40 CFR part 60, subpart VVa)
99	Other (specify)

[2] Use the definitions of “gas service,” “light liquid service,” and “heavy liquid service” in the regulation to which your process unit is subject, if applicable. See the list of definitions for this ICR for definitions of these terms to use if your process unit is not subject to a regulation that includes definitions of these terms.

[3] The information requested for open-ended lines refers to leakage from the open-end of a pipe or valve and not to leakage from the associated valve packing or body flanges.

[4] Other equipment includes any other fugitive emissions source not already provided that is monitored similar to equipment. Specify the types of fugitive emission sources.

[5] Do not include difficult-to-monitor equipment in this count.

[6] Select from the following list of monitoring frequencies the option that best applies for the fuel gas or natural gas system, type of equipment, and type of service. (For “other,” if you specified multiple types of fugitive emission sources and they have different monitoring frequencies, select the shortest monitoring interval for such sources.)

Code No.	Monitoring Frequency
0	None (unit/system not monitored for leaks)
1	No set interval (use only for sensory monitoring)
2	Less than annually
3	Annually
4	Semiannually
5	Quarterly
6	Monthly
7	Biweekly
8	Weekly or more frequently

[7] Select from the following list of leak definitions the monitored concentration above which repairs are required (or routinely performed) for the process unit, type of equipment, and type of service. (For "other," if you specified multiple types of fugitive emission sources and they have different leak definitions, select the lowest leak definition for such sources.)

Code No.	Leak Definition
0	None (unit/system not monitored for leaks)
1	Detection by sensory monitoring
2	10,000 ppmv
3	5,000 ppmv
4	2,000 ppmv
5	1,000 ppmv
6	500 ppmv
7	Less than 500 ppmv

5. Provide the information requested in Table 3-3 regarding pressure relief devices (PRD) on each process unit listed in Part I, Question 16 (except wastewater treatment) and for each fuel gas and natural gas system at the facility.

TABLE 3-3. Pressure Relief Devices

Unit ID, Fuel Gas System ID, or Natural Gas System	Total number of PRD	Number of PRD routed to fuel gas system or control device				Atmospheric PRD													
		Gas		Liquid		Gas							Liquid						
								Method 21 Monitoring for Leaks			Monitoring of Releases				Method 21 Monitoring for Leaks			Monitoring of Releases	
		Number of PRD	Type of controls[1]	Number of PRD	Type of controls[1]	Number of PRD	Number equipped with rupture disk or second valve	Number of PRD	Monitoring Frequency[2]	Leak Definition (ppmv)[3]	Number of PRD monitored using a system designed to measure the duration of a release and/or the quantity of compounds released	Describe your monitoring system	Number of PRD	Number equipped with rupture disk or second valve	Number of PRD	Monitoring Frequency[2]	Leak Definition (ppmv)[3]	Number of PRD monitored using a system designed to measure the duration of a release and/or the quantity of compounds released	Describe your monitoring system

Footnotes for Table 3-3:

[1] Select from the following list of controls. List all that apply to PRD in the process unit, fuel gas system, or natural gas system.

Code No.	**Type of Control**
0	None
50	Thermal or catalytic incinerator/oxidizer
51	Condenser
52	Carbon adsorber
55	Flare
61	Routed to fuel gas system
95	Management practice or work practice for VOC reduction (specify)
99	Other (specify)

[2] Select from the following list of Method 21 monitoring frequencies the option that best applies for the process unit, type of equipment, and type of service. Select "0" if the PRD are not monitored regularly on a set schedule (*i.e.*, they are only monitored after a release to confirm that there are no detectable emissions).

Code No.	**Monitoring Frequency**
0	None (unit/system not monitored for leaks using Method 21 (but may be monitored using sensory methods))
1	Less than annually
2	Annually
3	Semiannually
4	Quarterly
5	Monthly
6	Biweekly
7	Weekly or more frequently
8	Only after releases

[3] Select from the following list of leak definitions the monitored concentration above which repairs are required (or routinely performed) for the process unit and type of service. Select "0" if the PRD are not monitored regularly on a set schedule (*i.e.*, they are only monitored after a release to confirm that there are no detectable emissions).

Code No.	**Leak Definition**
0	None (unit/system not monitored for leaks using Method 21 (but may be monitored using sensory methods))
1	10,000 ppmv
2	5,000 ppmv
3	2,000 ppmv
4	1,000 ppmv
5	500 ppmv
6	Less than 500 ppmv

SECTION 4. STORAGE TANKS

1. Facility ID number (EPA will provide this number): ______________________

2. Does the facility receive unstabilized crude oil? **Yes** **No**

   If **Yes**, provide the following information:

   a. The quantity of unstabilized crude oil received in 2010: ______________ bbls

   b. The pressure at which the unstabilized crude oil is received: __________ psia

3. Does the facility receive use methane to blanket any storage tanks? **Yes** **No**

   If **Yes**, provide the quantity of methane used for storage tank blanketing:

   ____________________ MMscf at 60 °F and 1 atmosphere

4. Please provide information requested in Table 4-1 for each storage tank at the facility.

TABLE 4-1. Storage Tank General Information

																For tanks with EFR or IFR				
Tank ID	**Type of stored liquid[1]**	**Maximum true vapor pressure of hydrocarbons in stored liquid in 2010 (psi)**	**Temperature at which maximum true vapor pressure was calculated (°F)**	**Type of tank/controls[2]**	**Diameter (ft)**	**Height (ft)**	**Maximum liquid height (ft)**	**Total throughput for all materials stored in the tank in 2010 (bbl)**	**Is the tank a "drain-dry" tank? (Yes/No)**	**Applicable Federal air regulation(s)[3]**	**If subject to State, local, or Tribal air regulation(s), provide the citation(s)**	**Year in which the tank was last degassed**	**Type of control for last degassing event[4]**	**Was the tank cleaned during last degassing event? (Yes/No)**	**Year in which you anticipate the next degassing event[5]**	**Type of primary rim seal[6]**	**Type of secondary rim seal[7]**	**Minimum height of floating roof above the floor at the shell when**	**Number of times floating roof landed in 2010**	**Number of times the tank was emptied after roof landed in 2010**

Footnotes for Table 4-1:

[1] Report the type of liquid stored (or crude oil received) in the tank for the predominant use of the tank. Select from the following list of liquid types.

Code No.	Type of Stored Liquid
1	Unstabilized crude oil
2	Stabilized crude oil
3	Ethane
4	Ethylene
5	Propane
6	Propylene
7	Normal Butane
8	Butylene
9	Isobutane
10	Isobutylene
11	Unfinished Oils – Naphthas and lighter
12	Unfinished Oils – Kerosene and light gas oils
13	Unfinished Oils – Heavy gas oils
14	Unfinished Oils – Residuum
15	Finished Motor Gasoline - Reformulated
16	Finished Motor Gasoline - Conventional
17	Motor Gasoline Blending Components - Reformulated
18	Motor Gasoline Blending Components - Conventional
19	Aviation Gasoline – Finished and Blending Components
20	Special Naphthas (solvents)
21	Kerosene-type Jet Fuel
22	Kerosene
23	Distillate Fuel Oil – 15 ppm sulfur and under
24	Distillate Fuel Oil – greater than 15 ppm to 500 ppm sulfur
25	Distillate Fuel Oil – greater than 500 ppm sulfur
26	Residual Fuel Oil – less than 0.31% sulfur
27	Residual Fuel Oil – 0.31% to 1.0% sulfur
28	Residual Fuel Oil – greater than 1% sulfur
29	Lubricants (total)
30	Asphalt and Road Oil
31	Wax
32	Still Gas
33	Petrochemical Feedstocks – Naphtha <401°F end-point
34	Petrochemical Feedstocks - Other Oils ≥401°F end-point
35	Aromatics – Benzene
36	Aromatics – Toluene
37	Aromatics – Xylenes (total)
38	Aromatics – Other than BTX
99	Other (specify)

[2] Report the type of tank and controls. Select from the following list of tank types and controls. See the list of definitions for this ICR for details on what is considered a controlled guidepole.

Code No.	**Type of Tank/Control**
1	Fixed roof tank vented to atmosphere
2	Fixed roof tank vented to control device
3	Fixed roof tank using vapor balancing
4	External floating roof, slotted guidepoles
5	External floating roof with solid guidepoles
6	External floating roof, controlled guidepoles
7	Internal floating roof, slotted guidepoles
8	Internal floating roof with solid guidepoles
9	Internal floating roof, controlled guidepoles
10	External floating roof with geodesic dome roof
11	Horizontal tank
12	Pressurized/sphere tank
99	Other (specify)

[3] Select the Federal air regulation(s) to which the storage vessel is subject from the following list of regulations. Select all that apply, but include only regulations to which the storage vessel is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the storage vessel is subject).

Code No.	**Federal Air Regulation**
0	None
1	Refinery MACT (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT (40 CFR part 63, subpart CC) new source requirements
3	HON (40 CFR part 63, subpart H) existing source requirements
4	HON (40 CFR part 63, subpart H) new source requirements
5	NSPS for Storage Vessels (40 CFR part 60, subpart K)
6	NSPS for Storage Vessels (40 CFR part 60, subpart Ka)
7	NSPS for Storage Vessels (40 CFR part 60, subpart Kb)
8	Gasoline Distribution (40 CFR part 63, subpart R) existing source requirements
9	Gasoline Distribution (40 CFR part 63, subpart R) new source requirements
10	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) existing source requirements
11	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) new source requirements
99	Other (specify)

[4] Report the type of control used for the most recent degassing event. Select from the following list of controls.

Code No.	**Type of Degassing Control**
0	None; tank vented to atmosphere while being degassed
54	Portable internal combustion engine
55	Portable thermal oxidizer
56	Portable condensation system
57	Permanent onsite control device
99	Other (specify)

[5] Select the year in which you anticipate the next degassing event.

Code No.	**Year**
0	2010
1	2011
2	2012
3	2013
4	2014
5	2015
6	2016
7	2017
8	2018
9	2019
10	2020 or later

[6] Select the type of primary rim seal.

Code No.	**Type of Rim Seal**
0	None
1	Vapor-mounted seal; flexible wiper type
2	Vapor-mounted seal; resilient-filled type
3	Liquid-mounted seal
4	Mechanical-shoe seal

[7] Select the type of secondary rim seal.

Code No.	**Type of Rim Seal**
0	None
1	Rim-mounted seal
2	Shoe-mounted seal
3	Vapor-mounted seal; flexible wiper type

SECTION 5. CATALYTIC CRACKING UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 5-1 for each catalytic cracking unit (CCU) at the facility.

TABLE 5-2. Catalytic Cracking Unit Information

Unit ID for CCU	Fresh Feed Capacity (bbl/cd)	Recycle /Resid Capacity	Percent of CCU Feed that is Hydrotreated (%)	Typical Coke Burn Rate at Capacity (tons/cd)	Type of CCU (fluid, thermal, or other)	Type of CCU Regenerator (complete, partial, or variable)	Is there a CO boiler of other combustion device after CCU regenerator (Yes/No)?	Applicable Federal air regulation(s)[1]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	2010 Weighted Average Sulfur Concentration in Combined Feed (wt%)	2010 Weighted Average Nickel Concentration in Combined Feed (wt%)	2010 Weighted Average Vanadium Concentration in Combined Feed (wt%)	Type of PM controls[2]	Type of SO_2 controls[3]	Type of NO_X controls[4]

Footnotes for Table 5-2:

[1] Select the Federal air regulation(s) to which the CCU is subject from the following list of regulations. Select all that apply, but include only regulations to which the CCU is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the CCU is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 2 (40 CFR part 63, subpart UUU) existing source requirements
2	Refinery MACT 2 (40 CFR part 63, subpart UUU) new source requirements
3	Refinery NSPS (40 CFR part 60, subpart J)
4	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

[2] Select from the following list of PM controls; list all that apply.

Code No.	Type of PM Control
0	None
11	Fabric/cartridge filter ("baghouse")
12	Venturi/wet scrubber
13	Electrostatic precipitator (ESP)
14	Wet ESP
15	Tertiary cyclone
96	Management practice or work practice to reduce PM (specify)
99	Other (specify)

[3] Select from the following list of SO_2 controls; list all that apply.

Code No.	Type of SO_2 Control
0	None
24	Wet scrubber/flue gas desulfurization
25	Spray dryer absorber
26	DeSOx catalyst, meeting 50/25 ppmv SO_2 limit
27	DeSOx catalyst, meeting 20 lb/ton coke burn-off, but not 50/25 ppmv SO_2 limit
28	Low sulfur (0.3 wt% or less) feed
97	Management practice or work practice to reduce SO_2 (specify)
99	Other (specify)

[4] Select from the following list of NO_X controls; list all that apply.

Code No.	Type of NO_X Control
0	None
32	Staged air low NO_X burner in CO boiler or other post-combustion device
33	Staged fuel low NO_X burner in CO boiler or other post-combustion device
34	Ultra low NO_X burner (high fraction staged fuel) (ULNB) in CO boiler or other post-combustion device
35	"Next generation" low NO_X burner (ULNB with internal gas recirculation)) in CO boiler or other post-combustion device
36	Selective non-catalytic reduction (SNCR)
37	Selective catalytic reduction (SCR)
39	High-efficiency regenerator
40	Low NO_X combustion additives to replace Pt-based combustion additives
41	Other low NO_X catalyst additives
42	LoTOX® scrubber
98	Management practice or work practice to reduce NO_X (specify)
99	Other (specify)

3. If the facility has metal concentration for E-cat and/or fines, provide annual average values for each CCU at the facility in the Table 5-2 below.

TABLE 5-2. E-Cat and CCU Fines Metal Concentration

Unit ID for CCU	**Particle Type**	**Concentration (parts per million by weight, ppmw)**											
		Antimony	**Arsenic**	**Beryllium**	**Cadmium**	**Chromium**	**Cobalt**	**Lead**	**Manganese**	**Mercury**	**Nickel**	**Selenium**	**Vanadium**
	E-cat												
	Fines												
	E-cat												
	Fines												
	E-cat												
	Fines												
	E-cat												
	Fines												

SECTION 6. FLUID COKING UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 6-1 for each fluid coking unit (FCU) at the facility.

TABLE 6-1. Fluid Coking Unit Information

Unit ID for FCU	Feed Capacity (bbl/cd)	Type of FCU (traditional or flexicoker)	Applicable Federal air regulation(s)[1]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	If traditional coker							If flexicoker			
					Coke Production Capacity (tons/cd)	Typical Coke Burn Rate at Capacity (tons/cd)	Is there a CO boiler or other combustion device after FCU regenerator (Yes/No)?	Type of PM controls[2]	Type of SO_2 controls[3]	Type of NO_X controls[4]	Produced Coke Handling Controls and Disposition[5]	Low Btu gas production rate at capacity (scfm)	Low Btu gas sulfur removal technique[6]	FCU dust/ash quantity produced (tons/cd)	FCU dust/ash handling/disposal method[7]

Footnotes for Table 6-1:

[1] Select the Federal regulation(s) to which the FCU is subject from the following list of regulations. Select all that apply, but include only regulations to which the FCU is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the FCU is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

[2] Select from the following list of PM controls; list all that apply.

Code No.	Type of PM Control
0	None
11	Fabric/cartridge filter (“baghouse”)
12	Venturi/wet scrubber
13	Electrostatic precipitator (ESP)
14	Wet ESP
15	Tertiary cyclone
96	Management practice or work practice to reduce PM (specify)
99	Other (specify)

[3] Select from the following list of SO_2 controls; list all that apply.

Code No.	Type of SO_2 Control
0	None
24	Wet scrubber/flue gas desulfurization
25	Spray dryer absorber
28	Low sulfur (0.3 wt% or less) feed
97	Management practice or work practice to reduce SO_2 (specify)
99	Other (specify)

[4] Select from the following list of NO_X controls; list all that apply.

Code No.	Type of NO_X Control
0	None
32	Staged air low NO_X burner in CO boiler or other post-combustion device
33	Staged fuel low NO_X burner in CO boiler or other post-combustion device
34	Ultra low NO_X burner (high fraction staged fuel) (ULNB) in CO boiler or other post-combustion device
35	“Next generation” low NO_X burner (ULNB with internal gas recirculation)) in CO boiler or other post-combustion device
36	Selective non-catalytic reduction (SNCR)
37	Selective catalytic reduction (SCR)
39	High-efficiency regenerator
40	Low NO_X combustion additives to replace Pt-based combustion additives
41	Other low NO_X catalyst additives
42	LoTOX® scrubber
98	Management practice or work practice to reduce NO_X (specify)
99	Other (specify)

[5] Select from the following list the combination that best describes the coke handling and disposition method. For example, select 5E if you use the coke on-site in coke calciner and you use an enclosed conveyor to a storage bin with walls (wind breaks) and you wet the coke to suppress fugitive dust emissions.

Code No.	Disposition	Code Letter	Storage/Handling Method
1	Shipped off-site to coke calciner	A	Enclosed conveyer to silo for loading/processing
2	Shipped off-site to be used as fuel	B	Open conveyer to silo for loading/processing
3	Shipped off-site: some to coke calciner and some as fuel	C	Enclosed conveyer to open storage pile or bin, wind break only
4	Shipped off-site: other or unknown use	D	Enclosed conveyer to open storage pile or bin, wetting only
5	Processed in on-site coke calciner	E	Enclosed conveyer to open storage pile or bin, wind break and wetting
6	Used on-site as fuel	F	Open conveyance to open storage pile or bin, wind break only
7	Some used on-site as fuel, remainder sent off-site to coke calciner	G	Open conveyance to open storage pile or bin, wetting only
8	Some used on-site as fuel, remainder sent off-site for use as fuel	H	Open conveyance to open storage pile or bin, wind break and wetting
99	Other (specify)	Z	Other (specify)

[6] Select from the following list of low Btu gas sulfur controls.

Code No.	Low Btu Gas Sulfur Control
0	None
1	Conventional amine scrubber (*e.g.*, MEA, MDEA)
2	Sterically-hindered amine scrubber (*e.g.*, Flexsorb®)
3	Selexol®
4	Rectisol®
5	COS hydrolysis + conventional amine scrubber
6	COS hydrolysis + sterically-hindered amine scrubber
7	COS hydrolysis + Selexol®
8	COS hydrolysis + Rectisol®
9	Sulfinol®
98	Management practice or work practice (specify)
99	Other (specify)

[7] Select from the following list the method that best describes the flexicoking dust/ash handling and disposal method.

Code No.	Flexicoking Dust/Ash Handling and Disposal Methods
1	Used on-site as fuel
2	Disposed of in on-site landfill
3	Disposed of in off-site landfill
4	Shipped off-site for use as fuel
5	Shipped off-site for metals recovery
99	Other (specify)

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SECTION 7. DELAYED COKING UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 7-1 for each delayed coking unit (DCU) at the facility. For purposes of this information collection, a DCU consists of all drums connected to a single fractionator and the fractionator.

TABLE 7-1. Delayed Coking Unit Operating Information

											Cycle Time							Quench Water							
Unit ID for DCU	Feed Capacity (bbl/cd)	Coke Production Capacity (tons/cd)	Type of Coke Produced[1]	Number of Coke Drums	Height of Single Coke Drum (ft)	Diameter of Single Coke Drum (ft)	Typical Coke Drum Outage (ft)	Coke Drum Pressure When First Vented to Atmosphere (psig)	Coke Drum Temperature at Top of Drum When First Vented to Atmosphere (°F)	Water Height in Coke Drum When First Vented to Atmosphere (ft)	Complete Coke Drum Cycle Time (hr)[2]	Coke Drum Feed Cycle Time (hr)	Coke Drum Steam Purge Time (hr)	Coke Drum Water Quenching Time (hr)	Coke Drum Depressurization Vent Time (hr)	Coke Drum Coke Cutting Time (hr)	Coke Drum Preheat/Standby Time (hr)	Water Quenching Cycle Description[3]	Typical Quench Water Flow Rate during Quenching Cycle (gal/min)	Average Quench Water Make-up Rate (gal/day)	Purged Steam Blowdown System Description[4]	Quench Water Disposition[5]	Cutting Water Storage/Handling[6]	Applicable Federal air regulation(s)[7]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)

Footnotes for Table 7-1:

[1] Select from the following list of produced coke types.

Code No.	Quench Water Source
1	Needle coke, anode grade
2	Needle coke, fuel grade
3	Sponge coke, anode grade
4	Sponge coke, fuel grade
5	Shot coke, anode grade
6	Shot coke, fuel grade
99	Other (specify)

[2] Complete coke drum cycle time is from the start of one feed cycle to the start of the next feed cycle for a single drum and should equal feed time + steam time + cooling time + venting time + cutting time + preheat/standby time.

[3] Select from the following list of water quenching cycle descriptions.

Code No.	Quench Water Source
1	Use "tap" water (*i.e.*, water purchased directly from utility or drinking water)
2	Use process or recycled blowdown water
3	Use recycled cutting water with "tap" water make-up
4	Use recycled cutting water with process or blowdown water make-up
5	Use treated water from sour water stripper
6	Use treated water from wastewater treatment system
99	Other (specify)

[4] Select from the following list of blowdown system descriptions used to manage the steam exhausted during the steam purge and water quench cycles (prior to venting the vessel to atmosphere).

Code No.	**Condensed Water Disposition**	**Code Letter**	**Uncondensed Vapor Disposition When Not Sent Directly to DCU Fractionator**
1	Sent to wastewater treatment system	A	Not applicable; uncondensed vapors are always sent to DCU fractionator
2	Sent to sour water stripper	B	Uncondensed vapors are sent to dedicated DCU flare
3	Used to make steam	C	Uncondensed vapors are sent to flare header system to general facility flare
4	Recycled to unit and used as quench water	D	Uncondensed vapors are sent to flare gas recovery system
5	Used as coke cutting water	E	Uncondensed vapors are always sent directly to process heater or boiler
6	Used as general process water	F	Uncondensed vapors are always sent directly to amine treatment unit or fuel gas system
99	Other (specify)	G	Uncondensed vapors are controlled by oil scrubber or lean oil absorber prior to venting to atmosphere
		H	Uncondensed vapors are vented directly to atmosphere
		Z	Other (specify)

[5] Select from the following list of quench water disposition (referring to water drained from the drum after the vessel is vented to the atmosphere).

Code No.	**Quench Water Disposition**
1	Sent to wastewater treatment system
2	Sent to sour water stripper
3	Used to make steam
4	Recycled to unit and used as quench water
5	Used as coke cutting water
6	Used as general process water
99	Other (specify)

[6] Select from the following list of cutting water storage/handling method combinations.

Code No.	Cutting Water Source	Code Letter	Cutting Water Storage/Handling
1	Use "tap" water	A	Uncovered gravity settling pond
2	Use process or blowdown water	B	Covered gravity settling pond/tank
3	Use recycled cutting water with "tap" water make-up	C	Mechanical filtration (*e.g.*, centrifugal, filter press) to open storage tank or pond
4	Use recycled cutting water with process or blowdown water make-up	D	Mechanical filtration (*e.g.*, centrifugal, filter press) to covered storage tank or pond
5	Use treated water from sour water stripper	E	Directed to sour water stripper
6	Use treated water from wastewater treatment system	F	Directed to wastewater treatment system
99	Other (specify)	Z	Other (specify)

[7] Select the Federal air regulation(s) to which the DCU is subject from the following list of regulations. Select all that apply, but include only regulations to which the DCU is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the DCU is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

3. Provide typical and maximum feed composition in Table 7-2 for each DCU at the facility. You may list Unit ID numbers for multiple DCU in a single column if the DCU have similar feed compositions. If the DCU at the facility have different feed compositions, provide the typical and maximum feed compositions separately for each set of similar DCU.

TABLE 7-2. Delayed Coking Unit Feed Information

Feed Source	DCU ID(s): ____________		DCU ID(s): ____________	
	Typical % Feed[1]	**Maximum % Feed[2]**	**Typical % Feed[1]**	**Maximum % Feed[2]**
Atmospheric tower bottoms				
Heavy gas oil				
Vacuum tower bottoms				
Other residual gas oil				
Recovered materials				
- Recovered oil (*e.g.*, slop oil)				
- Sludges from crude oil storage tanks				
- Sludges from other storage tanks				
- Biosolids from wastewater treatment system				
- Other sludges from wastewater treatment system				
Other (specify): ____________				

Footnotes for Table 7-2:

[1] Typical or average feed composition for DCU. The sum of all values in this column should be 100%.

[2] Maximum percent of each feed source that can be used in the DCU. The sum of all values in this column is expected to exceed 100%.

SECTION 8. CATALYTIC REFORMING UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 8-1 for each catalytic reforming unit (CRU) at the facility.

TABLE 8-1. Catalytic Reforming Unit Information

Unit ID for CRU	Feed Capacity (bbl/cd)	Operating Pressure (psig)	Hydrogen Production Rate (purified basis) (MMscf/cd at 0°C	Type of CRU Regeneration (continuous, cyclic, or semi-regenerative)	Applicable Federal air regulation(s)[1]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Average Annual Regeneration Frequency (cyclic and semi-regen units; regeneration cycles/year)[2]	Average Annual Regeneration Time (hours/year)[2]	Depressurization /Purge Cycle Vent Disposition/control[3]	Purge Process Type[4]	Coke Burn-off Cycle Vent Disposition/control[5]	Coke Burn-off Cycle Duration per Cycle	Rejuvenation Cycle Vent Disposition/control[6]	Reduction or Activation Cycle Vent Disposition/control[7]	Chloriding Agent[8]

Footnotes for Table 8-1:

[1] Select the Federal air regulation(s) to which the CRU is subject from the following list of regulations. Select all that apply, but include only regulations to which the CRU is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the CRU is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 2 (40 CFR part 63, subpart UUU) existing source requirements
2	Refinery MACT 2 (40 CFR part 63, subpart UUU) new source requirements
99	Other (specify)

[2] If the unit does not regenerate catalyst at least once a year, estimate the number of cycles based on the interval between cycles. If the interval between cycles varies, you may use the interval between the two most recent cycles. For example, if regeneration occurs once every two years, then the number of cycles per year would be 1 cycle ÷ 2 years = 0.5 cycles per year. The number of hours per year may be estimated by multiplying an average number of hours per cycle by the calculated number of cycles per year.

[3] Select from the following list of purge controls.

Code No.	Type of Depressurization/Purge Control
0	Directly to the atmosphere
1	To fuel gas system, then atmosphere
2	To fuel gas system, then flare, then atmosphere
3	To flare, then atmosphere
4	To process heater or boiler, then atmosphere
95	Management practice or work practice to reduce VOC (specify)
99	Other (specify)

[4] Select from the following list of purge processes.

Code No.	Type of Purge Process
1	Purge by sequential pressurizing/purging with nitrogen
2	Purge using nitrogen and vacuum pump
3	Purge by sequential pressurizing/purging with methane
4	Purge using methane and vacuum pump
99	Other (specify)

[5] Select from the following list of coke burn-off controls.

Code No.	Type of Coke Burn-off Control
1	None
2	Caustic spray injection
3	Packed-bed wet scrubber
4	Tray tower wet scrubber
5	Chlorsorb™
94	Management practice or work practice to reduce HCl or chlorine releases (specify)
95	Management practice or work practice to reduce VOC (specify)
96	Management practice or work practice to reduce PM (specify)
99	Other (specify)

[6] Select from the following list of rejuvenation controls.

Code No.	Type of Rejuvenation Controls
0	Directly to the atmosphere
1	To fuel gas system, then atmosphere
2	To fuel gas system, then flare, then atmosphere
3	To flare, then atmosphere
4	To process heater or boiler, then atmosphere
94	Management practice or work practice to reduce HCl or chlorine releases (specify)
95	Management practice or work practice to reduce VOC (specify)
99	Other (specify)

[7] Select from the following list of reduction or activation controls.

Code No.	Type of Reduction or Activation Controls
0	Directly to the atmosphere
1	To fuel gas system, then atmosphere
2	To fuel gas system, then flare, then atmosphere
3	To flare, then atmosphere
4	To process heater or boiler, then atmosphere
94	Management practice or work practice to reduce HCl or chlorine releases (specify)
95	Management practice or work practice to reduce VOC (specify)
99	Other (specify)

[8] Select from the following list of chloriding agents.

Code No.	Type of Chloriding Agent
1	Perchloroethylene
2	Trichloroethene
99	Other (specify)

SECTION 9. SULFUR RECOVERY UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 9-1 for each sulfur recovery unit (SRU) at the facility.

TABLE 9-1. Sulfur Recovery Unit Information

Unit ID for SRU	Sulfur, Sulfur Cake or H_2SO_4 Production Capacity (long tons of sulfur/cd)	Type of SRU[1]	Sulfur Recovery Plant (SRP) ID[2]	Applicable Federal air regulation(s)[3]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Type of Tail Gas Treatment Unit[4]	Primary Sulfur Pit Controls	Primary Sulfur Pit Maintenance Time in 2010 (hr/yr)	SRU Back-up Controls/Reduction Measures[5]

Footnotes for Table 9-1:

[1] Select from the following list of sulfur recovery units.

Code No.	Type of Sulfur Recovery Unit
1	2-stage Claus
2	3-stage Claus
3	4-stage Claus
4	SuperClaus®
5	EuroClaus®
6	SubDewPoint MCRC-SuperClaus®
7	LoCat®
8	Caustic scrubber
9	Sulfuric acid plant
99	Other (specify)

[2] For purposes of this collection, multiple SRU are considered part of a single SRP when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are considered part of separate SRP.

[3] Select the Federal air regulation(s) to which the SRU is subject from the following list of regulations. Select all that apply, but include only regulations to which the SRU is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the SRU is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 2 (40 CFR part 63, subpart UUU) existing source requirements
2	Refinery MACT 2 (40 CFR part 63, subpart UUU) new source requirements
3	Refinery NSPS (40 CFR part 60, subpart J)
4	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

[4] Select from the following list of tail gas treatment processes used during normal operation of the unit. List all that apply.

Code No.	Type of Tail Gas Treatment Unit
0	None
1	Incinerator
2	Flare
3	SCOT unit
4	Beavon/amine
5	Beavon/Stretford
6	Cansolv®
7	LoCat®
8	Wellman-Lord
99	Other (specify)

[5] Select from the following list of SRU back-up measures.

Code No.	Type of SRU Back-up Control
0	None
1	Dedicated SRU flare
2	General plant flare
3	Divert to other SRU
4	Sulfur shedding (reduce production of high sulfur fuel gas)
98	Management practice or work practice (specify)
99	Other (specify)

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SECTION 10. HYDROGEN PLANT VENT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 10-1 for each hydrogen plant at the facility.

TABLE 10-1. Hydrogen Plant and Vent Information

Unit ID for Hydrogen Plant	Hydrogen Production Capacity (purified basis) (MMscf/sd at 0°C and 1 atm)	Type of Hydrogen Production Unit[1]	Applicable Federal air regulation(s)[2]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Hydrogen Purification Method Used[3]	Type of Feedstock Used[4]	Steam Generation Rate (lb/hr)	PSA Purge/Off Gas Flow Rate (scfm)	PSA Purge/Off Gas Disposition[5]	Reformer Deaerator Vent Flow Rate (scfm)	Other Atmospheric Vent (Yes/No)? (If yes, report in Table 11-1)

Footnotes for Table 10-1:

[1] Select from the following list of hydrogen production units.

Code No.	Type of Hydrogen Production Unit
1	Steam-methane reforming
2	Partial oxidation
3	Electrolysis
4	Gasification
99	Other (specify)

[2] Select the Federal air regulation(s) to which the hydrogen plant is subject from the following list of regulations. Select all that apply, but include only regulations to which the hydrogen plant is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the hydrogen plant is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
99	Other (specify)

[3] Select from the following list of hydrogen purification processes.

Code No.	**Type of Hydrogen Purification Process**
1	Pressure-swing adsorption
2	Membrane separation
3	Cryogenic separation
99	Other (specify)

[4] Select from the following list of feedstocks.

Code No.	**Type of Hydrogen Production Unit Feedstock**
1	Methane
2	Refinery fuel gas
3	Refinery fuel gas augmented with additional methane
99	Other (specify)

[5] Select from the following list of dispositions for the PSA Purge/Off Gas.

Code No.	**Disposition of the PSA Purge/Off Gas**
1	Used as fuel in the reformer furnace
2	Used as fuel elsewhere in the refinery
3	Sent to flare
4	Vented to atmosphere
99	Other (specify)

SECTION 11. OTHER ATMOSPHERIC VENTS

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 11-1 for each "other atmospheric vent" at the facility. "Other atmospheric vents" include any continuous or intermittent process vents located at the facility and under common control other than those vents specifically covered in Sections 5 through 10 of this part (Part II), vents associated with process heater or boiler exhausts, and wastewater vents. "Other atmospheric vents" include distillation tower vents; blowdown systems vents, knock-out pot vents, vacuum ejectors (hot well vents), analyzer vents as well as vents from Merox™ treatment systems, fuel gas treatment units (if any), catalytic hydrocracking units (if any), asphalt blowing stills, and coke calcining units. The focus of this section is primarily on vents directed directly to the atmosphere during normal operation, and vents recycled to process units, vents directed to a fuel gas system, or vents directed to a flare are not considered "other atmospheric vents". Also, "other atmospheric vents" do not include pressure relief vents where venting occurs only during upset, startup, or shutdown events or vents associated with storage tanks.

TABLE 11-1. Other Atmospheric Vent Information

Atmospheric Vent ID	**Type of Atmospheric Vent**[1]	**Unit ID (if applicable) with which the Vent is Associated**[2]	**Applicable Federal air regulation(s)**[3]	**If subject to State, local, or Tribal air regulation(s), provide the citation(s)**	**Atmospheric Vent Operating Hours**[4]	**Atmospheric Vent Controls**[5]

Footnotes for Table 11-1:

[1] Select from the following list of processes and equipment the option that best describes the type of unit or equipment associated with this vent.

Code No.	Type of Other Atmospheric Vent
1	Atmospheric crude distillation column/reflux condenser vent
2	Catalytic cracking unit distillation column/reflux condenser vent
3	Catalytic hydrocracking unit distillation column/reflux condenser vent
4	Catalytic reforming unit distillation column/reflux condenser vent
5	Coking unit distillation column/reflux condenser vent
6	Other distillation column/reflux condenser vent
7	Vacuum distillation column vacuum system exhaust vent
8	Hot well vent/vacuum jet exhaust
9	Other vacuum system exhaust
10	Drier regeneration vent
11	Coke calcining vent
12	Asphalt blowing still vent
13	Blow down system vent
14	Knock-out pot vent
15	Analyzer vent
16	Process tank (including surge control vessels, bottoms receivers, etc.)
99	Other (specify)

[2] Enter the Unit ID associated with the vent only if the vent is associated with only one process unit. If the vent is in general use or used by multiple process units, leave this question blank. (Any further detail you wish to provide may be included in the “Notes” to this form.

[3] Select the Federal air regulation(s) to which the “other atmospheric vent” is subject from the following list of regulations. Select all that apply, but include only regulations to which the vent is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the vent is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	Refinery NSPS (40 CFR part 60, subpart J)
4	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

[4] Select from the following list of operating scenarios.

Code No.	Type of Operation
1	Continuous (operates whenever the process is operating)
2	Intermittent; 4,000 hours per year or more
3	Intermittent; 2,000 hours or more but less than 4,000 hours per year
4	Intermittent; 1,000 hours or more but less than 2,000 hours per year
5	Intermittent; less than 1,000 hours per year

[5] Select from the following list of control devices. List all that apply.

Code No.	Type of Control Device
0	None
11	Fabric/cartridge filter ("baghouse")
12	Venturi/wet scrubber
13	Electrostatic precipitator (ESP)
14	Wet ESP
24	Wet scrubber/flue gas desulfurization
36	Selective non-catalytic reduction (SNCR)
37	Selective catalytic reduction (SCR)
50	Thermal or catalytic incinerator/oxidizer
51	Condenser
52	Carbon adsorber
95	Management practice or work practice to reduce VOC (specify)
96	Management practice or work practice to reduce PM (specify)
97	Management practice or work practice to reduce SO_2 (specify)
98	Management practice or work practice to reduce NO_X (specify)
99	Other (specify)

SECTION 12. FLARES

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 12-1 for each flare at the facility.

TABLE 12-1. Flare Information

Flare ID Number or Description	If the flare is dedicated to one processing unit, enter the Unit ID	Flare Diameter (ft)	Flare release height (ft)	Flare Location (Latitude)	Flare Location	Type of Flare[1]	Flare Assist Type[2]	Target Assist Ratio (if applicable)	Type of Flare Pilot or Ignition System[3]	Applicable Federal air regulation(s)[4]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Typical Lower Heating Value of Waste Gas (Btu/scf @ 60°F)	Flare Operating Hours[5]	Flare Management Plan[6]	Flare Reduction

Footnotes for Table 12-1:

[1] Select from the following list of flares.

Code No.	Type of Flare
1	Elevated flare
2	Elevated flare, pressure assisted
3	Ground level flare
4	Ground level flare, pressure assisted
99	Other (specify)

[2] Select from the following list of flare assist types.

Code No.	Flare Assist Types
1	Unassisted
2	Steam assisted
3	Air assisted
99	Other (specify)

[3] Select from the following list of flare pilot or ignition systems.

Code No.	Type of Flare Pilot or Ignition System
1	Continuous pilot flame
2	Spark ignition, every minute regardless of flow
3	Spark ignition, triggered by flow sensor/monitor
99	Other (specify)

[4] Select the Federal air regulation(s) to which the flare is subject from the following list of regulations. Select all that apply, but include only regulations to which the flare is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the flare is subject).

Code No.	Federal Air Regulation
0	None
1	General Provisions (40 CFR part 60, subpart A)
2	General Provisions (40 CFR part 63, subpart A)
3	Refinery NSPS (40 CFR part 60, subpart J)
4	Refinery NSPS (40 CFR part 60, subpart Ja)
99	Other (specify)

[5] Select from the following list of operating scenarios the option that best describes the operation of the flare.

Code No.	Type of Operation
1	Combusts flare gas 4,000 hours per year or more
2	Combusts flare gas 2,000 hours or more but less than 4,000 hours per year
3	Combusts flare gas1,000 hours or more but less than 2,000 hours per year
4	Combusts flare gas less than 1,000 hours per year
5	Combusts flare gas only during startup or shutdown
6	Combusts flare gas only during upsets
7	Combusts flare gas only during startup, shutdown, or upsets

[6] Select from the following list of components of flare management plans the option that best describes the scope of the flare management for the flare; list all that apply.

Code No.	Components of Flare Management Plan
0	Not applicable. Do not have a flare management plan for minimizing flaring from this flare.
1	Simplified P&ID (process and instrument diagram) of flare header system
2	Description of streams from process units that can be directed to the flare
3	Procedures to reduce start-up and shutdown releases to the flare
4	Operational procedures for specific process units to reduce releases to the flare during normal process operations
5	Procedures to reduce/minimize purge or sweep gas use
5	Procedure to conduct a root cause and corrective action analysis for flare events exceeding a set SO_2 emission level
6	Procedures to conduct root cause and corrective action analysis for flare events exceeding a set flow rate level
7	Procedures for monitoring flow of gas to the flare
8	Procedures for monitoring Btu of flared gas
9	Procedures for monitoring sulfur content of flared gas
99	Other (specify)

[7] Select from the following list of flare reduction measures that are specifically used to reduce emissions from the flare. List all that apply.

Code No.	Type of Control Device
1	Amine treatment of the flare gas (include only amine treatment used specifically to reduce SO_2 emissions from the flare, not amine treatment systems used the fuel gas system)
2	Flare gas recovery system, but not designed to recover 100 percent of flare gas during normal operations
3	Flare gas recovery system designed to recover 100 percent of flare gas during normal operations
4	Root cause and corrective action analysis for flare events exceeding a set SO_2 emission level
5	Root cause and corrective action analysis for flare events exceeding a set flow rate level
95	Other management practice or work practice to reduce VOC (specify)
96	Other management practice or work practice to reduce PM (specify)
97	Other management practice or work practice to reduce SO_2 (specify)
98	Other management practice or work practice to reduce NO_X (specify)
99	Other (specify)

SECTION 13. FUEL GAS TREATMENT UNIT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 13-1 for each fuel gas treatment unit at the facility.

TABLE 13-1. Fuel Gas Treatment Unit Information

Fuel Gas Treatment Unit ID	Unit ID for each process unit that generates fuel Gas treated in the treatment unit	Type of sulfur removal technique(s) used[1]	Fuel gas flow rate at treatment unit capacity (scfm)	Average fuel gas flow rate into the treatment unit (scfm)	Estimated operating hours in 2010	Types of sulfur compounds in the untreated fuel gas[2]	Estimated annual average H_2S concentration in treated fuel gas exiting the treatment unit (ppmv)	Estimated annual average total sulfur concentration in the treated fuel gas exiting the treatment unit (ppmv)	Applicable SO_2 federal air regulation(s) for combustion units that burn the fuel gas[3]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Are there any atmospheric vents in the system (Yes/No)? (If yes, report in Table 11-1)

Footnotes for Table 13-1:

[1] Select from the following list of sulfur removal techniques; list all that apply.

Code No.	Type of Sulfur Removal Technique
1	Absorption using MDEA solvent
2	Absorption using MEA solvent
3	Absorption using DEA solvent
4	Absorption using DIPA solvent
5	Absorption using DGA solvent
6	Absorption using blend of amine(s) and TG-10 solvent
7	Flexsorb® process
8	Selexol® process
9	Rectisol® process
10	Sulfinol® process
11	Merox™ process
12	COS hydrolysis
13	Hot potassium carbonate
14	LoCat®
15	Caustic scrubber
16	Sodium hydrosulfide (NaSH) production process
99	Other (specify)

[2] Select from the following list of sulfur containing compounds; list all that apply.

Code No.	Type of Sulfur Containing Compound
1	Hydrogen sulfide (H_2S)
2	Carbonyl sulfide (COS)
3	Carbon disulfide (CS_2)
4	Mercaptans
5	Thioethers
99	Other (specify)

[3] Select the Federal regulation(s) to which the fuel gas combustion units are subject from the following list of regulations. Select all that apply, but include only regulations to which the fuel gas combustion units are subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the combustion units are subject).

Code No.	Federal Air Regulation for the Fuel Gas Combustion Units
0	None
1	Refinery NSPS (40 CFR part 60, subpart J)
2	Refinery NSPS (40 CFR part 60, subpart Ja)
3	Steam Generation NSPS (40 CFR part 60, subpart D)
4	Steam Generation NSPS (40 CFR part 60, subpart Db)
5	Steam Generation NSPS (40 CFR part 60, subpart Dc)
99	Other (specify)

SECTION 14. HEAT EXCHANGE (COOLING WATER) SYSTEMS

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide information requested in Table 14-1 for each heat exchange (HE) system at the facility.

TABLE 14-1. Cooling Water System Information

HE System ID Number or Description	Unit IDs for Process Units Serviced by Cooling Water System	Cooling Water System Operation – Fluid	Cooling Water System VOC/HAP Concentration[2]	Type of Cooling Water System[3]	Applicable Federal air regulation(s)[4]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Cooling Water Flow/ Recirculation Rate (gal/min)	Water Make-up Rate (gal/min)	Gas or Chemical Additive/Disinfection Method[5]	Gas or Chemical Addition Rate Value	Gas or Chemical Addition Rate Units (volume or mass per time)	Chemical Addition Location

Footnotes for Table 14-1:

[1] Select from the following list of cooling water system operations.

Code No.	Type of Cooling Water System Operation – Fluid Pressure
1	Services only heat exchangers in which the maximum process fluid pressure is lower than the minimum water pressure
2	Services at least one heat exchanger in which the maximum process fluid pressure is higher than the minimum water pressure

[2] Select from the following list of descriptions of the cooling water system VOC and HAP concentrations.

Code No.	Cooling Water System VOC/HAP Concentration
1	Services only heat exchangers in which the process fluid contains less than 5 wt% VOC and less than 5 wt% organic HAP
2	Services at least one heat exchanger in which the process fluid contains at least 5 wt% VOC but no heat exchangers with 5 wt% or more organic HAP
3	Services at least one heat exchanger in which the process fluid contains at least 5 wt% organic HAP

[3] Select from the following list of types of cooling water systems.

Code No.	Type of Cooling Water System
1	Once-through cooling water system
2	Natural draft cooling tower
3	Induced draft cooling tower (fans at outlet)
4	Forced draft cooling tower (fans for inlet air)
99	Other (specify)

[4] Select the Federal air regulation(s) to which the cooling water system is subject from the following list of regulations. Select all that apply, but include only regulations to which the cooling water system is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the cooling water system is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	HON (40 CFR part 63, subpart H) existing source requirements
4	HON (40 CFR part 63, subpart H) new source requirements
99	Other (specify)

[5] Select from the following list of chemical additives.

Code No.	Type of Chemical Additive/Disinfection Method
1	Chlorine from gas cylinders
2	Sodium hypochlorite
3	Calcium hypochlorite
4	Chloramine
5	Ozonation
6	UV disinfection
99	Other (specify)

SECTION 15. WASTEWATER COLLECTION AND TREATMENT

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide the following information for the facility.

   a. What is the daily average wastewater treatment system flow rate (or discharge rate if wastewater is treated off-site)?

   b. What is the Total Annual Benzene (TAB) quantity for the facility?

   c. Indicate the Benzene Waste Operations NESHAP (BWON) (40 CFR part 61, subpart FF) compliance option selected by the facility.

      1 2 Mg/yr
      2 6 BQ
      3 Not applicable because TAB < 10 Mg/yr
      4 Other (specify)

3. Please provide the following information about wastewater generated from tank drawdowns:

   a. Estimated quantity of wastewater generated via tank draw downs in 2010? ___ gallons

   b. Quantity of benzene in wastewater generated via tank draw downs in 2010? ___ lbs

   c. Average VOC content of wastewater generated via tank draw downs in 2010? ___ ppmw

4. Complete Table 15-1 to indicate the wastewater treatment processes used for each wastewater treatment system (identified in Part 1, Question 16) at the facility and the applicable air regulations for each selected unit.

TABLE 15-1. Wastewater Treatment Processes

Wastewater Treatment System ID	Type of Wastewater Treatment Process[1]	For Steam and Sour Water Strippers, also Provide Average Steam Usage Rates in 2010 (lb/hr)	Applicable Federal air regulation(s)[2]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)

Footnotes for Table 15-1:

[1] Select from the following list of wastewater treatment processes.

Code No.	Wastewater Treatment Process
0	None (no on-site wastewater treatment units present at facility)
1	Benzene/VOC steam stripper
2	Oil-water separator
3	Dissolved air/gas flotation
4	Equalization basin/tank
5	Neutralization basin/tank
6	Activated-sludge biological treatment unit
7	Aerated surface impoundment
8	Non-aerated surface impoundment
9	Anaerobic sludge digester
10	Aerobic sludge digester
11	Other biological treatment unit (trickling filter, rotating biological contactor)
12	Primary clarifier
13	Secondary clarifier
14	Sour water stripper

[2] Select the Federal air regulation(s) to which the selected wastewater treatment unit is subject from the following list of regulations. Select all that apply, but include only regulations to which the wastewater treatment unit is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the wastewater treatment unit is subject).

Code No.	**Compliance Applicability**
0	The unit is not subject to any air standards.
1	The unit is subject to BWON (40 CFR part 61, subpart FF) but exempted from control requirements.
2	The unit is subject to BWON (40 CFR part 61, subpart FF) control requirements.
3	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
4	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
5	HON (40 CFR part 63, subpart H) existing source requirements
6	HON (40 CFR part 63, subpart H) new source requirements
7	Refinery Wastewater NSPS (40 CFR part 60, subpart QQQ)

5. Please provide the information requested in Table 15-2 for each process unit that routinely generates wastewater.

TABLE 15-2. Wastewater Generation Information

Process Unit ID	Average wastewater generation rate (gallons/operating day)	Average benzene concentration (ppmw)	Average concentration of organic HAP (ppmw)	Average VOC concentration (ppmw)

6. Please provide information requested in Table 15-3 for each "wastewater vent" at the facility. "Wastewater vents" include atmospheric vents associated with wastewater drain systems and gases purged from covered wastewater treatment systems.

TABLE 15-3. Wastewater Vent Information

Atmospheric Vent ID	Description of Atmospheric Vent[1]	Applicable Federal air regulation(s)[2]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Atmospheric Vent Operating Hours[3]	Atmospheric Vent Controls[4]

Footnotes for Table 15-3:

[1] Select from the following list of wastewater vents the option that best describes this vent.

Code No.	Type of Unit/Equipment Associated with Vent
1	Drain system vent
2	Vent from wastewater treatment unit
99	Other (specify)

[2] Select the Federal air regulation(s) to which the selected wastewater vent is subject from the following list of regulations. Select all that apply, but include only regulations to which the wastewater vent is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the wastewater treatment unit is subject).

Code No.	Compliance Applicability
0	The vent is not subject to any air standards.
1	The vent is subject to BWON (40 CFR part 61, subpart FF) but exempted from control requirements.
2	The vent is subject to BWON (40 CFR part 61, subpart FF) control requirements.
3	Refinery MACT (40 CFR part 63, subpart CC) existing source requirements
4	Refinery MACT (40 CFR part 63, subpart CC) new source requirements
5	HON (40 CFR part 63, subpart H) existing source requirements
6	HON (40 CFR part 63, subpart H) new source requirements
7	Refinery Wastewater NSPS (40 CFR part 60, subpart QQQ)

[3] Select from the following list of operating scenarios.

Code No.	Type of Operation
1	Continuous (operates whenever the wastewater treatment process is operating)
2	Intermittent; 4,000 hours per year or more
3	Intermittent; 2,000 hours or more but less than 4,000 hours per year
4	Intermittent; 1,000 hours or more but less than 2,000 hours per year
5	Intermittent; less than 1,000 hours per year

[4] Select from the following list of control devices. List all that apply.

Code No.	Type of Control Device
0	None
50	Thermal or catalytic incinerator/oxidizer
51	Condenser
53	Single carbon adsorber canister
54	Two carbon adsorber canisters in series
95	Management practice or work practice to reduce VOC (specify)
99	Other (specify)

SECTION 16. LOADING OPERATIONS

1. Facility ID number (EPA will provide this number): ______________________

2. Please provide the following information regarding products transported by marine vessels (tank ships and barges).

   a. Select the option that best describes the marine vessel loading operations that are associated with the refinery's shipments via marine vessels (as reported in Question 15 of Part I of this ICR).

   0 None. There are no shipments made via marine vessels
   1 Marine vessel operations are contiguous with the refinery.
   2 Marine vessel operations are conducted on-shore but are not contiguous with the refinery.
   3 Marine vessel operations are conducted off-shore (*i.e.*, more than 0.5 miles from the coast).

   b. For the marine vessel operations associated with the refinery's shipments, are there vessels or barges loaded that contain non-segregated ballast water?

   Yes **No**

   c. If **Yes**, is non-segregated ballasting water (from either on-site or off-site marine vessel loading operations) treated in the refinery's wastewater treatment plant?

   Yes **No**

3. Please provide the following information regarding products transported by tank truck or rail car.

   a. Select the option that best describes the tank truck operations that are associated with the refinery's shipments via tank truck (as reported in Question 15 of Part I of this ICR).

   0 None. There are no shipments made via tank truck
   1 Tank truck loading operations are conducted on-site (*i.e.*, considered part of the refinery facility).
   2 Tank truck loading operations are conducted off-site (not part of the contiguous refinery facility).

   b. Select the option that best describes the rail car operations that are associated with the refinery's shipments via rail truck (as reported in Question 15 of Part I of this ICR).

   0 None. There are no shipments made via rail car
   1 Rail car loading operations are conducted on-site (*i.e.*, considered part of the refinery facility).
   2 Rail car loading operations are conducted off-site (not part of the contiguous refinery facility).

4. Please provide the information requested in Table 16-1 for each fixed location loading operation (*e.g.*, dock, loading rack) at the facility (*i.e.*, those considered part of the refinery facility).

TABLE 16-1. Loading Information

Unit ID for loading operation	**Type of vessel loaded**[1]	**Capacity loading throughput (gal/yr)**	**Applicable Federal air regulation(s)**[2]	**If subject to State, local, or Tribal air regulation(s), provide the citation(s)**	**Typical annual operating hours (hr/yr)**	**Does the facility or parent company own the vessels being loaded? (Yes/No)**	**Type of control device or control technique**[3]

Footnotes for Table 16-1:

[1] Select from the following list of vessels. List all that apply.

Code No.	Type of Vessel
1	Tank ship
2	Barge
3	Truck/tank truck
4	Rail car
5	Containers with capacity less than 250 gallons
6	Containers with capacity from 250 gallons to less than 1,000 gallons
7	Containers with capacity from 1,000 gallons to less than 20,000 gallons
8	Containers with capacity greater than or equal to 20,000 gallons
99	Other (specify)

[2] Select the Federal air regulation(s) to which the loading/unloading location is subject from the following list of regulations. Select all that apply, but include only regulations to which the loading/unloading location is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the loading/unloading location is subject).

Code No.	Federal Air Regulation
0	None
1	Refinery MACT 1 (40 CFR part 63, subpart CC) existing source requirements
2	Refinery MACT 1 (40 CFR part 63, subpart CC) new source requirements
3	HON (40 CFR part 63, subpart H) existing source requirements
4	HON (40 CFR part 63, subpart H) new source requirements
5	Gasoline Loading NSPS (40 CFR part 60, subpart XX)
6	Gasoline Distribution (40 CFR part 63, subpart R) existing source requirements
7	Gasoline Distribution (40 CFR part 63, subpart R) new source requirements
8	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) existing source requirements
9	Gasoline Distribution (40 CFR part 63, subpart BBBBBB) new source requirements
99	Other (specify)

[3] Select from the following list of control devices and techniques; list all that apply.

Code No.	Type of Control
0	None
50	Thermal or catalytic incinerator/oxidizer
51	Condenser
52	Carbon adsorber
55	Flare
80	Submerged loading
82	Bottom loading
83	Vapor balancing system
95	Other management practice or work practice to reduce VOC (specify)
99	Other (specify)

SECTION 17. SOLID WASTE MANAGEMENT

1. Facility ID number (EPA will provide this number): ______________________

2. Describe any pollution prevention methods used to reduce the quantity of solid waste disposed of on-site and the percent and/or quantity of waste reduced (*e.g.*, reduced sludge disposal from tank cleanings by 80% by recycling oily sludges to delayed coking unit).

   ____

   ____

3. Please provide information requested in Table 17-1 for each active landfill, land application unit, waste pile, or composting operation at the facility.

TABLE 17-1. Solid Waste Management Unit Information

Solid Waste Management ID Number	Type of Solid Waste Management Unit[1]	Description of Waste Managed in Unit	Area of Solid Waste Management Unit (m^2)	Capacity of Solid Waste Management Unit (m^3)	Applicable Federal air regulation(s)[2]	If subject to State, local, or Tribal air regulation(s), provide the citation(s)	Waste Application or Disposal Rate (m^3/yr)	Bulk Density of Waste Applied or Disposed (g/cm^3)	Pretreatment or Control Methods Used[3]

Footnotes for Table 17-1:

[1] Select from the following list of solid waste management system types.

Code No.	Type of Solid Waste Management Unit
1	Hazardous waste (RCRA Subtitle C) landfill
2	Industrial waste (RCRA Subtitle D) landfill
3	Land application unit
4	Waste pile
5	Composting operation

[2] Select the Federal air regulation(s) to which the solid waste management unit is subject from the following list of regulations. Select all that apply, but include only regulations to which the solid waste management unit is subject according to the applicability of the regulation (*i.e.*, do not select regulations that are referenced from the regulation(s) to which the solid waste management unit is subject).

Code No.	Federal Air Regulation
0	None
99	Other (specify)

[3] Select from the following list of solid waste pretreatment or control methods. List all that apply.

Code No.	Type of Pretreatment or Control Method
1	Dewatering
2	Fixation (solidification/stabilization)
3	Steam stripping
4	Water for dust suppression
5	Oil for dust suppression
6	Foam for dust suppression
7	Leachate collection
8	Landfill gas collection
99	Other (specify)

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OMB Control No. ____-____
Approval Expires __/__/__

PART III. INCIDENCE REPORTS

1. Complete the following table for each non-routine emissions event during 2010.

Date of release	Type of release (startup/shutdown; equipment or component malfunction)	Description of release event	Process units associated with the release	Duration of the release event (hours)	Pollutant name	Pollutant CAS No. or Pollutant Code	Quantity of pollutant released (lb)	Quantity determination method (measured or calculated)

2. Complete the following table for each flare, air emission, or odor complaint received in 2010.

Date of complaint	Complainant name	Complainant contact information	Substance of complaint

PART IV. COST DATA

For any air pollution control devices (APCD), process changes, equipment changes/upgrades, and management or work practices implemented within the last 5 years for which you have readily available cost information, please provide those costs as described in this part. Include only process changes, equipment changes/upgrades, and management or work practices implemented to reduce emissions. Do not include projects needed to meet environmentally driven product specifications (*e.g.*, low sulfur diesel projects, ethanol blending projects, and gasoline reformulation projects to remove MTBE). If you wish to provide more detail than requested in Table 2 (*e.g.*, you wish to itemize total capital costs), you may provide your information in a separate spreadsheet. If you know an approximate cost for a control technique but do not have the level of detail requested in the tables, please provide the approximate cost and your best estimate of which of the components in the appropriate table were factored into that approximate cost (in lieu of completing the applicable table for that control technique).

If any of the data requested in this part is considered CBI, follow the instructions in the section “Submitting CBI” under the heading “How to Submit Your Survey Response” in the introduction to this enclosure.

1. Please complete Table 1 for any new APCD installed in the last 5 years on any of the process units or other emissions sources described in Part II for which you have readily available information. The EPA is particularly interested in costs of the following APCD:

- Electrostatic precipitators
- Wet scrubbers
- Baghouses
- SCR/SNCR for NO_X control
- Steam strippers
- Carbon adsorbers
- Thermal/catalytic oxidizers
- Flares

2. Please complete Table 2 for any process changes or equipment changes/upgrades performed in the last 5 years to any of the process units or other emissions sources described in Part II for which you have readily available information. The EPA is particularly interested in costs of the following process changes or equipment changes/upgrades:

- Installation of low/ultra-low NO_X burners
- Installation of air preheat for process heaters/boilers
- Catalyst additives for SO_X control from FCCU
- Combustion promoters or catalyst additives for NO_X control from FCCU

- Amine treatment systems
- Floating roofs, rim seals, and fittings seals on storage vessels
- Installation of geodesic dome for external floating roof tank
- Installation of guidepole sleeves/wipers or other tank fitting gaskets

3. Please provide any readily available costs for other techniques used at your refinery to reduce emissions of any pollutant. EPA is particularly interested in techniques that are not already included in Federal regulations. Provide as much detail in your cost estimate as possible (*e.g.*, unit ID for the unit from which emissions are reduced, amount of time needed to complete the technique (labor costs), cost of any equipment needed on a temporary basis, cost of any monitoring devices needed to indicate when action is needed or to measure progress). Types of techniques that EPA is particularly interested in include:

- Use of a portable or temporary control device (*e.g.*, for degassing of storage tanks)
- Monitoring devices (*e.g.*, monitors that record the duration and quantity of compounds released from a PRD)
- Pollution prevention techniques
- Energy management programs identified in Part II, Section 1
- Other management practices or work practices that you identified in Part II

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Approval Expires __/__/__

Table 1. Cost Data for APCD[1]

APCD ID	Unit ID associated with this APCD	APCD Type[2]	APCD Size[3]	New or retrofit APCD[4]	Year of APCD installation	Expected APCD equipment life (yrs)	Demolition Cost of previous APCD, if any ($)	CAPITAL COSTS: Base year for capital costs	CAPITAL COSTS: Purchased equipment costs ($)[5]: Primary equipment ($)[6]	Purchased equipment costs ($)[5]: Auxiliary equipment ($)[7]	Purchased equipment costs ($)[5]: Instrumentation and monitors ($)	Purchased equipment costs ($)[5]: Sales tax and freight ($)	Purchased equipment costs ($)[5]: Total purchased equipment costs ($)	Installation costs ($)[8]	Total Installed Cost of APCD[9]	ANNUAL OPERATING COSTS[10]: Base year for operating costs	Operating labor ($): hr/yr	Operating labor ($): $/hr	Maintenance labor ($): hr/yr	Maintenance labor ($): $/hr	Utilities ($): Electricity: kWh/yr	Utilities ($): Electricity: $/kWh	Utilities ($): Water: gal/yr	Utilities ($): Water: $/gal	Utilities ($): Steam: lb/yr	Utilities ($): Steam: $/lb	Utilities ($): Natural gas: scf/yr	Utilities ($): Natural gas: $/scf	Utilities ($): Liquid chemicals: gal/yr	Utilities ($): Liquid chemicals: $/gal	Utilities ($): Solid chemicals: lb/yr	Utilities ($): Solid chemicals: $/lb	Utilities ($): Compressed Air: scf/yr	Utilities ($): Compressed Air: $/scf	Utilities ($): Other (specify): amt/yr	Utilities ($): Other (specify): $/amt	Total utilities cost ($/yr)[12]	Waste disposal ($): amt/yr	Waste disposal ($): $/[illegible]	Supplies and parts[13]: Description of most significant part	Supplies and parts[13]: Number of years between replacements	Supplies and parts[13]: Replacement cost (with installation)	Monitoring, recordkeeping & reporting ($/yr)	Other annual costs (itemize)[14]: 1	Other annual costs (itemize)[14]: 2	Other annual costs (itemize)[14]: 3	Total annual operating & maintenance cost[15]

[1] Columns that are sums of other columns are shaded gray. If you do not have the all detail requested but you do have an estimate for a subtotal, enter the subtotal in the appropriate shaded column and provide as much detail or explanation as you have available.

[2] See list following the last footnote for codes corresponding to APCD types.

[3] Provide the numerical value as well as the units (*e.g.* scfm).

[4] If the APCD was installed at the time the process unit or emission source was constructed, enter "New." If the APCD was installed after the process unit or emission source began operation, enter "Retrofit."

[5] Sum of equipment, auxiliary equipment, instrumentation/monitors, sales tax, and freight.

[6] Primary equipment is the APCD itself. Examples include SCR with catalyst, carbon adsorber with carbon, packed scrubber tower with packing, fabric filter with bags, ESP, and steam stripper column with nozzles, manholes, and trays.

[7] Examples of auxiliary equipment include fans, pumps, motors, duct work, stacks, flame arrestors, and condensers and decanters for steam strippers.

[8] Include all installation costs (*e.g.*, foundations, supports, handling/erection, electrical, piping, insulation for ductwork and piping, painting, engineering, construction and field expenses, contractor fees, start-up, and testing.

[9] Sum of purchased equipment cost and installation cost.

[10] Provide operating costs for the last 12 month period (calendar or fiscal year) for which the refinery has data.

[11] Specify units.

[12] For each utility that applies to this APCD, multiply the consumption rate (the first column for that utility) by the unit cost (the second column for that utility) to get the annual cost for each utility. Add the individual utility annual costs to get the total utilities cost.

[13] Include the most significant of the major supplies and replacement parts; examples include catalyst for SCR and catalytic incinerators, bags for fabric filters, and carbon for carbon adsorbers.

[14] An example might be catalyst regeneration. Note that this question is not asking for costs of maintenance materials, capital recovery, overhead, administration, property taxes, and insurance because EPA will estimate these costs as a function of other costs.

[15] Sum of annual costs for operating labor; maintenance labor; utilities; waste disposal; major supplies and replacement parts that are needed once per year or more frequently; monitoring, recordkeeping, and reporting; and any other items included under “other annual costs.”

Code No.	Type of APCD
1	Amine treatment (*e.g.*, installation of new amine treatment unit)
2	Caustic spray injection
3	Packed-bed wet scrubber
4	Tray tower wet scrubber
5	Chlorsorb™
11	Fabric/cartridge filter ("baghouse")
12	Venturi/wet scrubber
13	Electrostatic precipitator (ESP)
14	Wet ESP
15	Tertiary cyclone
24	Wet scrubber/flue gas desulfurization
25	Spray dryer absorber
36	Selective non-catalytic reduction (SNCR)
37	Selective catalytic reduction (SCR)
42	LoTOX® scrubber
50	Thermal or catalytic incinerator/oxidizer
51	Condenser
52	Carbon adsorber
53	Single carbon adsorber canister
54	Two carbon adsorber canisters in series
55	Flare
56	Portable internal combustion engine
57	Portable thermal oxidizer
58	Portable condensation system
59	Permanent onsite control device for storage tanks
60	Flare gas recovery
83	Vapor balancing system
99	Other (specify)

Table 2. Cost Data for Process and Equipment Changes

Unit ID	Process or equipment change type[1]	Process or equipment change description[2]	Year of process or equipment change	Number of days process shut down in order to make the change (days of lost production)[3]	Total capital cost, $[4]	Change in total annual operating cost, $/yr[5]	Emission reduction achieved (if quantified)[6]

[1] See list following the last footnote for codes corresponding to process or equipment changes. If none of the codes describe your process or equipment change, enter "99" and specify the type of process or equipment change.

[2] Describe the process or equipment change. Be as descriptive as possible. For example, for installation of low NO_X or ultra low NO_X burners for a process heater, note the number of new burners, their sizes, and the fuel options (*e.g.*, fuel gas, oil).

[3] Enter number of days of lost production required to implement the process or equipment change. If the change occurred during scheduled downtime that would have occurred regardless of the process or equipment change, then do not include the scheduled downtime. Only the days of lost production that can be specifically attributed to the process or equipment change are of interest.

[4] Please distinguish between one-time capital and annual operating costs where appropriate. If a breakdown of the specific capital or annual cost items is available, please provide as a separate attachment.

[5] Provide changes in annual operating costs (if estimated). Otherwise, leave blank. Include annual operating costs that are an increase to prior operating costs (*e.g.*, additional operating costs due to installation of low NO_X burners). If the process or equipment change resulted in decreased annual operating costs, then indicate the cost decrease as a negative number.

[6] Describe the air pollutants affected and emissions reduction achieved. Indicate the basis for emissions reduction reported (*e.g.*, air emissions testing before and after modification). You may provide this information as a separate attachment to your response if you wish.

Code No.	**Type of Process or Equipment Change**
1	Amine treatment (change in existing amine treatment system operation)
21	H_2S limit in fuel gas
22	TRS limit in fuel gas
23	Low sulfur distillate or heavy gas oil
26	DeSOx catalyst, meeting 50/25 ppmv SO_2 limit
27	DeSOx catalyst, meeting 20 lb/ton coke burn-off, but not 50/25 ppmv SO_2 limit
28	Low sulfur (0.3 wt% or less) feed
31	(External) flue gas recirculation
32	Staged air low NO_X burner
33	Staged fuel low NO_X burner
34	Ultra low NO_X burner (high fraction staged fuel) (ULNB)
35	“Next generation” low NO_X burner (ULNB with internal gas recirculation)
39	High-efficiency regenerator
40	Low NO_X combustion additives to replace Pt-based combustion additives
41	Other low NO_X catalyst additives
70	Water seal
71	Fixed seal
72	Hard piping
80	Submerged loading (*i.e.*, loading from the top of the vessel; the fill pipe extends almost to the bottom of the vessel such that it is below the liquid level during most of the filling)
82	Bottom loading
99	Other (specify)

PART V. EMISSIONS MONITORING AND SOURCE TEST DATA

In this section, emissions test data are requested. Please satisfy this request as completely as possible from existing information. No additional monitoring or emission testing is required by your company to respond to the data request in this section. Four types of existing emissions data are requested: 1) source test data, 2) qualified CEMS data, 3) biological treatment units data, and 4) ambient or remote sensing data. The emissions test data collected will provide valuable information on current emissions levels and will allow EPA to consider variability in emissions from refinery to refinery (and over time for a given emission unit and pollutant) in reviewing and setting emission standards. When submitting test data, EPA is requesting full test reports with field and lab data sheets and example calculations, not just summary reports.

If any of the data requested in this part is considered CBI, follow the instructions in the section "Submitting CBI" under the heading "How to Submit Your Survey Response" in the introduction to this enclosure.

1. Source Tests: Provide any existing emissions test reports from emissions tests conducted on any of the processes or emission points included in Part II, Sections 3 through 17 on or after January 1, 2005. Electronic (pdf) or hard copies are acceptable. Include the summary portion of the report and any appendices showing run-by-run test parameters, method detection limits, laboratory data, production data, example calculations, etc. If you have multiple tests for one pollutant from one process unit, submit only the most recent tests for that pollutant and process unit. (We are only requesting a maximum of the three most recent tests per unit for one pollutant, but you may submit more than three, particularly if additional tests reflect the effect of different operating conditions or equipment configurations.)

   In addition, complete the source test log shown in Attachment 1 for each source test you submit. (Electronic copies of this table can be downloaded from the ICR website (https://refineryicr.rti.org).) Note that the information requested in the summary table includes:

   (A) APCD type (if not clear from the test report),

   (B) a description of how the configuration of the emission unit, combustion controls, collection system, or APCD has changed since the test was conducted, if applicable,

   (C) any notes specific to that emissions test (optional), and

   (D) how often you are required to test the emission unit (optional).

2. Qualified CEMS Data: Provide qualified CEMS data for PM, CO, NO_X, SO_2, O_2, and THC CEMS on any of the processes or emission points included in Part II, Sections 2 through 17. Report daily averages for each day in 2010 using the Microsoft® Excel CEMS Template; an example template is shown in Attachment 2. The Excel templates are specific to each pollutant and type of unit, and each template is designed to

accommodate data from one CEMS (including oxygen data). Electronic copies of the template can be downloaded from the ICR website (https://refineryicr.rti.org).

Qualified CEMS data include: data from a PM CEMS that meets Performance Specification 11 or 15; data from a CO CEMS that meets Performance Specification 4; data from a SO_2 and/or NO_X CEMS that meets Performance Specification 2; data from a THC CEMS that meets Performance Specification 8A; or data from any CEMS meeting the accuracy and ongoing QA/QC requirements of 40 CFR part 60, Appendix F. Use only qualified CEMS data and determine the daily averages using by averaging the hourly CEMS values for each hour for which qualified CEMS data are available. If there are no qualified CEMS data for any hour in a given day, report "ND" (no data) for that daily average.

3. Qualified CMS Data: Provide qualified CMS data for H_2S, reduced sulfur, total reduced sulfur, hydrocarbon, and Btu CMS on fuel gas or flare gas lines. Report daily averages for each day in 2010 using the Microsoft® Excel CMS Template; an example template is shown in Attachment 2. The Excel templates are specific to each pollutant and type of unit, and each template is designed to accommodate data from one CMS. Electronic copies of the template can be downloaded from the ICR website (https://refineryicr.rti.org).

   Qualified CMS data include: data from a H_2S CMS that meets Performance Specification 7; data from a reduced sulfur or total reduced sulfur CMS that meets Performance Specification 7; data from a hydrocarbon or Btu CMS (gas composition monitor) that meets Performance Specification 5; data from any CMS meeting the accuracy and ongoing QA/QC requirements of 40 CFR part 60, Appendix F; or data from any CMS for that has been calibrated per the manufacturer's specifications within the past 12 months and is operated and maintained (including on-going QA/QC requirements) according to the manufacturer's specifications. Use only qualified CMS data and determine the daily averages using by averaging the hourly CMS values for each hour for which qualified CMS data are available. If there are no qualified CMS data for any hour in a given day, report "ND" (no data) for that daily average.

4. Biological treatment unit: If you performed a biodegradation rate test or a complete mixing test on a biological treatment unit on or after January 1, 2000, provide a complete copy of the test report.

5. Ambient and remote sensing: If you conducted ambient air monitoring or conducted a DIAL, SOF, or similar test at or around your facility on or after January 1, 2000, provide a complete copy of the test report for these studies.

6. Equipment leak correlations: If you developed site-specific correlations for equipment leaks at your facility and you use those correlations to estimate emissions from equipment leaks, provide a complete copy of the report or other documentation describing the testing and development of the correlations.

Attachment 1 Log of Source Tests Provided

Test Number[1]	Unit ID(s)	If the APCD type(s) is not clear from the test report, enter the APCD type(s)	Configuration changes[2]	OPTIONAL: Process testing notes[3]	OPTIONAL: How often are you required to perform testing of this emission unit for the pollutants listed?	OPTIONAL: Approximate cost per test, $

[1] Assign a test ID or number to each test report that you provide so that EPA can match your responses in this log to the correct test report.

[2] If the configuration of the emission unit, combustion controls, collection system, or APCD changed since the test was conducted, describe the changes. If there are no configuration changes, enter "N/A"

[3] Use this column for notes or if helpful to specify the emission points tested (*e.g.*, for equipment with multiple emission points, where only selected emission points/vents were tested)

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

Attachment 2. Example CEMS Table

NO_X CEMS DATA

Emission Unit ID:

CEMS Date (mm/dd/ yyyy)	Daily production/ throughput rate (value)[1]	Daily production/ throughput rate (units)	1-day average emission value for NO_X (as measured by the CEMS)	Unit of measure recorded by CEMS	O_2 content (%)	Moisture content (%)	Data average affected by a startup, shutdown, or other event?[1]	OPTIONAL: Emission value (ppmvd @ 7% O_2)	OPTIONAL: 1-day average emission value for NO_X in other units		
									1-day average emission value for NO_X, corrected for $\%O_2$ (value)	1-day average emission value for NO_X, (units)	% O_2 correction (by volume, dry basis)
01/01/2010											
01/02/2010											
01/03/2010											
01/04/2010											
01/05/2010											
01/06/2010											
01/07/2010											
01/08/2010											
……											
12/25/2010											
12/26/2010											
12/27/2010											
12/28/2010											
12/29/2010											
12/30/2010											
12/31/2010											

[1] Provide the process production rate, heat input rate, coke burn-off rate or other normalizing factor appropriate for the type of process.

[2] If no, leave blank. If yes, respond “startup,” “shutdown,” or “event”; if you respond “event” please include a brief description of the event.