



# New Federal & State Rules for Oil & Gas Facilities

*40 CFR 98 Subpart W  
& 30 TAC 106.352*



# 40 CFR 98 Mandatory Reporting of Greenhouse Gases

*Subpart W Petroleum and  
Natural Gas Systems*

# Industry Segments



Offshore petroleum and natural gas production

Onshore petroleum and natural gas production

Onshore natural gas processing plants

Onshore natural gas transmission compression

Underground natural gas storage

Liquefied natural gas (LNG) storage

LNG import and export equipment

Natural gas distribution

# Facility

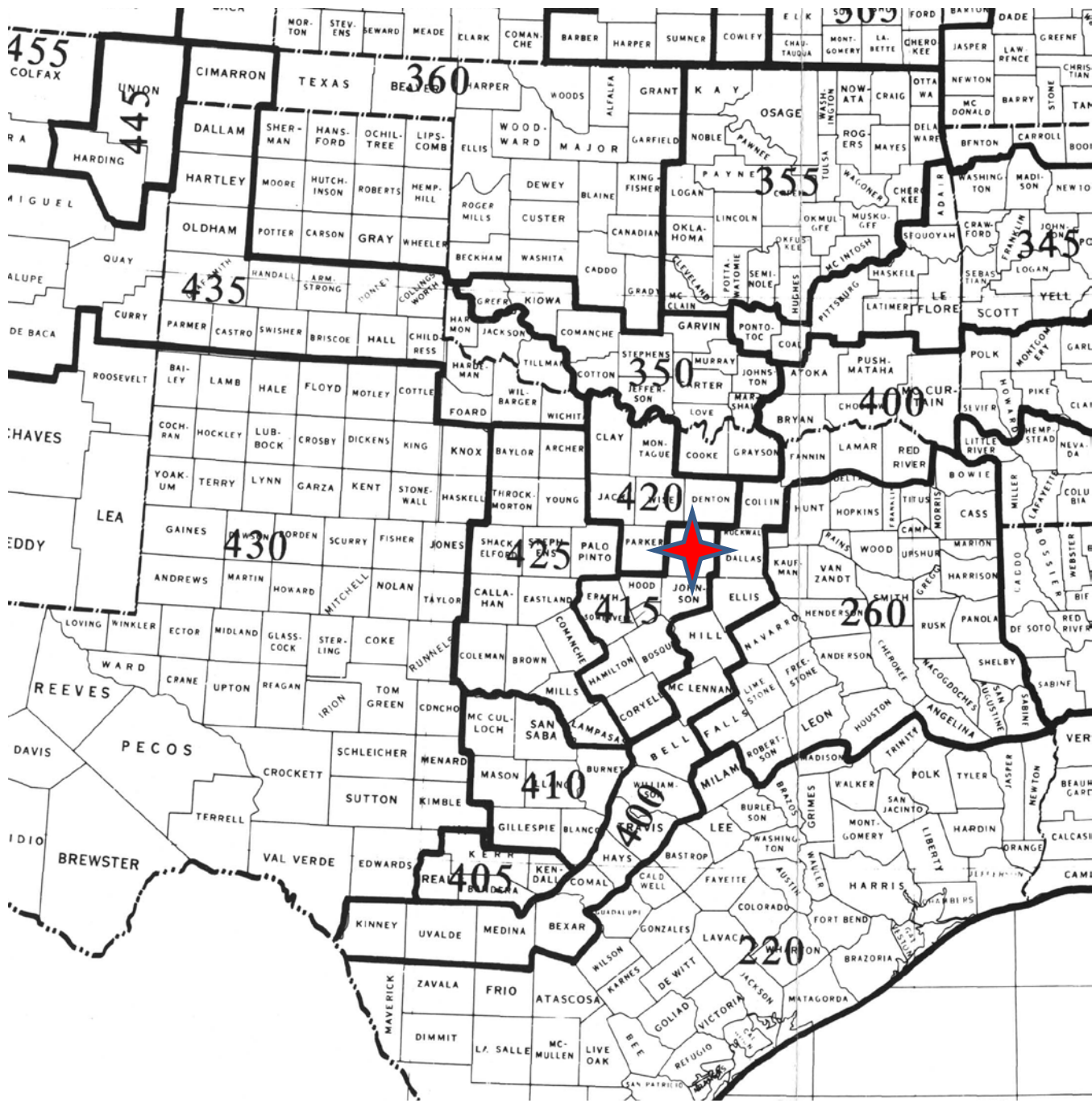


Onshore natural gas processing plants / Onshore natural gas transmission compression facilities are defined by their physical boundaries and ownership structures traditionally used to define a facility.

Onshore petroleum and natural gas production facilities include "all petroleum or natural gas equipment on a well pad or associated with a well pad and CO<sub>2</sub> EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin..."



Can be purchased at [www.aapg.org](http://www.aapg.org) in either pdf or GIS format.



- Barnett Shale includes:
- 350 South
  - 345 Oklahoma folded belt
  - 400 Ouachita folded belt
  - 415 Strawn basin
  - 420 Fort Worth syncline
  - 425 Bend arch

# Applicability



- Facilities with carbon dioxide equivalent (CO<sub>2</sub>e) emissions greater than 25,000 metric tons or more per year beginning in 2011.
- Include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters with external combustion rated heat capacity above 5 MMBtu/hour
- Emissions from gathering lines and boosting stations are currently not required to be reported

# Screening Tool



- Available at

<http://www.epa.gov/climatechange/emissions/GHG-calculator/index.html>

- Spreadsheet with default emission factors
- Input equipment populations and anticipated operations for 2011

# Leak Monitoring



- The Onshore petroleum and natural gas production segment requires an equipment count in order to determine fugitive emissions
- The Onshore natural gas processing plants and Onshore natural gas transmission compression segments require that fugitive emissions sources and emission rates be determined once per year using an optical gas imaging instrument per the *Alternative work practice for monitoring equipment leaks (AWP)*, Method 21, or infrared laser beam illuminated instrument

# BAMM



- Best Available Monitoring Methods = temporary use of alternative data for compliance such as supplier data, company records, or engineering calculations
- Allowed Jan. 1- ~~June 30~~ Sept. 30, 2011 with no approval for
  - Direct measurement of gas well venting (with hydraulic fracturing) and well testing venting and flaring
  - Activity counts such as hours of venting, production volume, number of blowdowns, completions, etc..
- Allowed Jan. 1-Dec. 31, 2011 with written approval for leak detection monitoring, requests due ~~April 30~~ July 31, 2011

# Source Types by Industry Segment

Source Type	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression
Natural gas pneumatic device venting	X		X
Natural gas driven pneumatic pump venting	X		
Acid gas removal vent	X	X	
Dehydrator vent	X	X	
Well venting for liquids unloading	X		
Gas well venting during well completions and workovers with hydraulic fracturing	X		
Gas well venting during well completions and workovers without hydraulic fracturing	X		
Blowdown vent stacks	X	X	X
Onshore production storage tanks	X		
Transmission storage tanks			X
Well testing venting and flaring	X		
Associated gas venting and flaring	X		
Flare stacks	X	X	
Centrifugal compressor venting	X	X	X
Reciprocating compressor rod packing venting	X	X	X
Other emissions from equipment leaks	X	X	X
Population Count and Emissions Factor	X		
Enhanced Oil Recovery hydrocarbon liquids dissolved CO <sub>2</sub>	X		
Enhanced Oil Recovery injection pump blowdown	X		
Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions	X		

# Reporting



- Data collection began January 1, 2011
- Annually report carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) emissions
- First report due March 31, 2012
- Submit electronically through e-GGRT
- Submit a Certification of Representation form at least 60 days before March 31, 2012 (by January 30, 2012)
- Report emissions in aggregate by industry segment and source type
- Designated GHG calculation methodology per source type
- GHG reporting for combustion sources, other than flares, must use Subpart C methods and procedures

# Emission Calculation Methods

Source Type	Engineering Estimates	Direct Measurement	Leak Detection and Leaker Emission Factor	Equipment Count and Population Emission Factor
Natural gas pneumatic device venting				X
Natural gas driven pneumatic pump venting				X
Well venting for liquids unloading	X	X		
Gas well venting during well completions without hydraulic fracturing	X			
Gas well venting during well completions with hydraulic fracturing		X		
Gas well venting during well workovers without hydraulic fracturing	X			
Gas well venting during well workovers with hydraulic fracturing		X		
Onshore production storage tanks	X			X
Transmission storage tanks		X		
Reciprocating compressor rod packing venting		X		
Well testing venting and flaring	X			
Associated gas venting and flaring	X			
Dehydrator vent	X			X
EOR injection pump blowdown	X			
Acid gas removal vent	X	X		
EOR hydrocarbon liquids dissolved CO <sub>2</sub>		X		
Centrifugal compressor venting		X		
Other emissions from equipment leaks			X	X
Blowdown vent stacks	X			
Flare stacks	X	X		
Stationary and portable combustion emissions	X	X		

# Recordkeeping



- Keep a record of all data required to conduct GHG emissions calculations such as equipment population counts (i.e. pneumatic bleed devices, pumps, wells vented to the atmosphere), total instances of operations conducted (i.e. well completions, compressor blowdowns), annual throughput of natural gas or other products, laboratory analyses, and fugitive emissions monitoring.
- Record the results of all emissions measurements with their date, time, location, and operating condition.
- Keep calibration reports for detection and measurement instruments.
- Record calculation variables as well as computer model input/output data used for engineering estimation of emissions.

# Recordkeeping



Prepare a GHG Monitoring Plan that includes:

- Identification of positions of responsibility for data collection
- Explanation of the processes and methods used for data collection
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all flow meters and other instrumentation used to provide data for GHG reporting including calibration, calibration accuracy, and associated technical justifications.

# Checklists



- Available at <http://www.epa.gov/climatechange/emissions/subpart/w.html>
- One per industry segment
- An easy way to get organized / attack the data



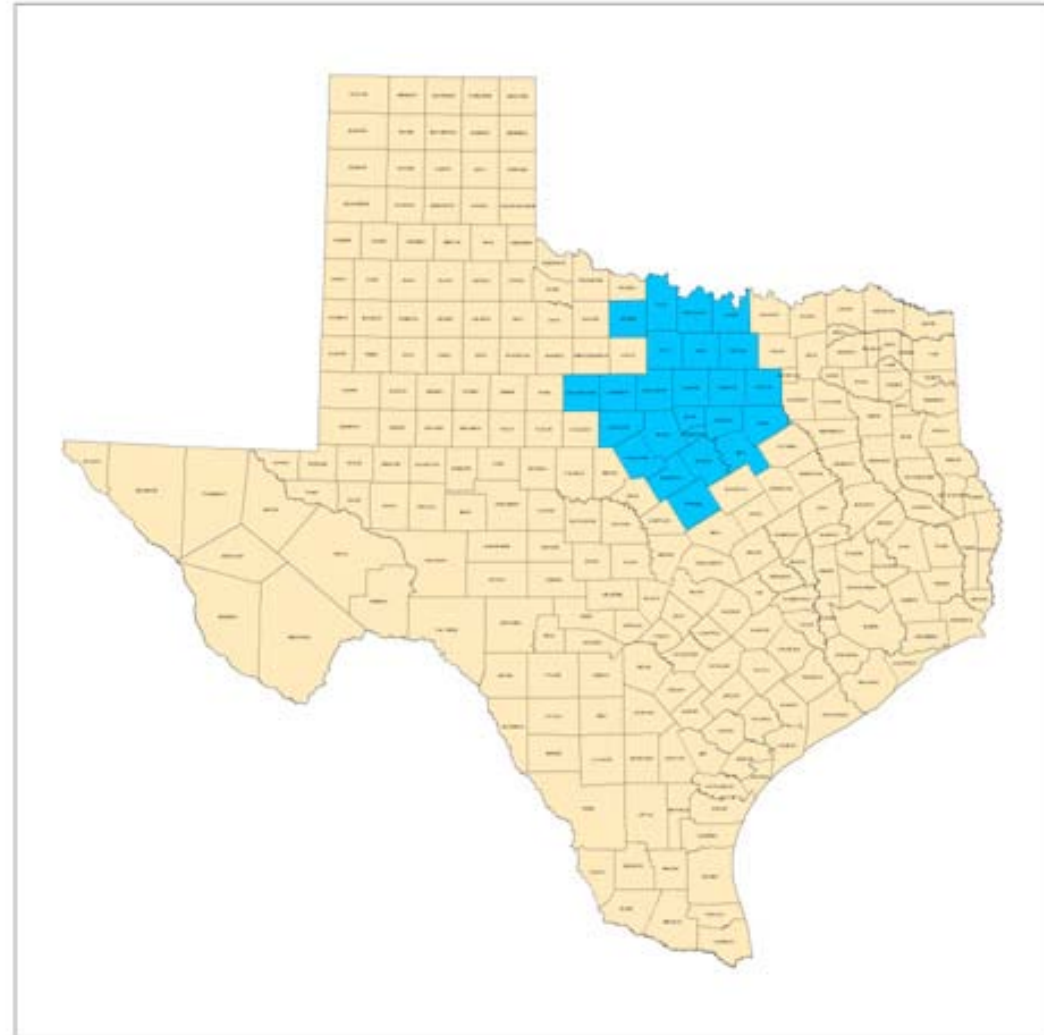
# Revised Permit by Rule 30 TAC 106.352

*Oil and Gas Handling and  
Production Facilities*

# Applicability



- New projects and related facilities on or after April 1, 2011
- Biggest impact on Barnett Shale



# Key Definitions



**Facility** = a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a **stationary emission source**, excluding drilling operations and well tests lasting < 72 hours

–Wellhead

–Tank

–Separator

–Compressor

–Free Water Knockout

–Piping

–Fugitive Components

–Dehydrator

# Key Definitions



**Oil and Gas Site (OGS)** = all **facilities** that are

- (1) located on contiguous or adjacent properties;
- (2) under common control; and
- (3) designated under the same two digit SIC code

# Restrictions



- Only one PBR authorization allowed per OGS
- Emissions must be based on
  - representative worst-case operations
  - planned MSS activities
- Each PBR authorization must include all OGS facilities within  $\frac{1}{4}$  mile that are operationally dependent on the project
- If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds  $\frac{1}{4}$  mile, then the facilities are considered separate

# Existing OGS - No Project



- By January 5, 2012 meet MSS requirements
- By January 1, 2013 submit Core Data and basic site information through ePermits "APD OGS Historical Notification" with no fee
- If already registered, only submit hardcopy Core Data if updates are needed

# Existing OGS- New Project



- Existing authorized facilities with no change to type or quantity of emissions
  - comply with Protectiveness Review / MSS
  - include in new project registration
  - otherwise retain existing authorization
- Existing authorized facilities with changes to type or quantity of emissions
  - fully comply with the new requirements and
  - obtain a new authorization {limited exceptions}

# New Project-Level 0



New projects with site wide combinations from Group 1 and/or Group 2 need only comply with applicable BMPs and recordkeeping and require no notification or registration until another new project occurs

## Level 0 Criteria

Group	Product	Engines	Piping and Fugitive Components					Produced Water Separators*	Produced Water Tanks
			Open-ended Lines	Valves	Connectors & Flanges	Pump Seals	All Others		
1	Sweet Gas	≤ 450 HP	---	---	---	---	---	---	---
	Sour Gas (H <sub>2</sub> S ≤ 10,000 ppm)	≤ 100 HP	---	---	---	---	---	---	---
	Sour Gas (H <sub>2</sub> S > 10,000 ppm, ≤ 50,000 ppm)	≤ 20 HP	---	---	---	---	---	---	---
2	Natural Gas	---	≤ 135	≤ 135	≤ 2,000	---	≤ 135	---	---
	Liquids or Natural Gas	---	≤ 25	≤ 25	≤ 2,000	---	≤ 25	---	---
	Liquids or Natural Gas	---	≤ 4	≤ 225		≤ 4	---	---	---
	Crude, Condensate and/or Natural Gas	---	≤ 5	≤ 150 (VOC service) & ≤ 500 (water service)		≤ 5	---	No limit	≤ 1,205 bbl/day
	Crude, Condensate and/or Natural Gas	---	≤ 2	≤ 230 (VOC service) & ≤ 500 (water service)		≤ 2	---	No limit	≤ 580 bbl/day

\* routed directly to sales pipeline

# New Project-Level 1 & Level 2



- Prior to construction submit notification with Core Data and project description through the ePermits “APD OGS New Project Notification”; \$50 fee (\$25 for small businesses)
- Post-construction register through ePermits “APD OGS PBR Level 1 and Level 2 Registration”

# Level 1 & Level 2 Criteria

Emissions Limits*		Level 1	Level 2
Pollutant	Units		
Total crude oil or condensate VOC	lb/hr**	100	100
Total natural gas VOC	lb/hr	204	356
Total VOC	TPY	15	25
Benzene	lb/hr	1.95	3.35
	TPY	2.8	4.8
H <sub>2</sub> S	lb/hr	4.7	6
	TPY	20.6	25
SO <sub>2</sub>	lb/hr	47	63
	TPY	25	25
NO <sub>x</sub>	lb/hr	43.2	54.4
	TPY	100	250
CO	lb/hr	45	57
	TPY	100	250
PM <sub>2.5</sub>	lb/hr	10	12.7
	TPY	5	10
PM <sub>10</sub>	lb/hr	10	12.7
	TPY	5	15
Registration		Within 180 days after start of operation or implemented change(s)	Within 90 days after start of operation or implemented change(s)
Fees		\$175 (\$25 for small businesses)	\$400 (\$75 for small businesses)

\*Emissions after recovery or controls

\*\*Steady state, with separate periodic limits

# Impacts Evaluation



- Receptors = residential buildings, schools, day cares, hospitals, businesses, places of worship
  - present at the time of registration
  - excludes structures used solely by the OGS owner, OGS operator, and mineral rights owners
- Include all (new and existing) OGS facility emissions within  $\frac{1}{4}$  mile of project

# Impacts Evaluation



- No evaluation necessary if emissions are below these limits:

4 lb/hr  $\text{NO}_x$

2 lb/hr  $\text{SO}_2$

0.025 lb/hr  $\text{H}_2\text{S}$

0.039 lb/hr benzene

- Modeling on a contaminant-by-contaminant basis for net emissions increases
  - TCEQ Generic Modeling reference tables or
  - Screening / Refined dispersion modeling

# Impacts Evaluation



- Demonstrate compliance with  $\text{NO}_x$ ,  $\text{SO}_2$ , and  $\text{H}_2\text{S}$  ambient air standards at any property line within  $\frac{1}{4}$  mile of a Level 1 project or  $\frac{1}{2}$  mile of a Level 2 project
- No further review required if a contaminant's maximum predicted concentration is  $\leq$  the significant impact level
- Demonstrate compliance with benzene hourly ( $170 \mu/\text{m}^3$ ) and annual ( $4.5 \mu/\text{m}^3$ ) ESLs at the nearest receptor within  $\frac{1}{4}$  mile of a Level 1 project or  $\frac{1}{2}$  mile of a Level 2 project
- No further review required if the benzene maximum predicted concentration is  $\leq$  10% of the applicable ESL

# Required BMPs



- Maintenance program:
  - (1) manufacturer's requirements relevant to equipment performance and effect on emissions;
  - (2) cleaning/routine inspection of all equipment;
  - (3) equipment replacement/repair on schedules to prevent equipment failures and maintain performance
- New facilities must operate at least 50 feet from any property line or receptor, whichever is closer
- Fugitive components physically inspected quarterly for leaks
- Applicable engine emissions limits per manufacture date, engine type, and horsepower rating (stack testing if > 500 HP)

# Required BMPs



- Open-topped tanks/ponds PTE limit:  
1.0 TPY VOC                      0.1 TPY H<sub>2</sub>S
- Leaks repaired within 30 days (manned sites) and within 60 days (unmanned sites)
- Tank hatches must remain closed except for sampling, gauging, loading, unloading, or planned maintenance
- As allowed by GEP, locate new and reworked valves and piping connections so that they are accessible for leak checking
- No buried valves such that fugitive emission monitoring is impractical

# Optional BMPs



- Applicable if the relevant equipment or control device is chosen by the operator to meet PBR emissions limitations:
- Leak detection and repair (LDAR) fugitive monitoring
  - Tank/vessel paint color
  - Process reboilers, heaters, and furnaces (used for control of waste gas streams)
  - Vapor Recovery Units (VRU) inlet/outlet testing
  - Flares
  - Thermal oxidation and vapor combustion control devices

# MSS



- Before January 5, 2012, voluntary representation and registration of planned MSS, must meet emission limits
- After January 5, 2012, planned MSS emissions must be considered for compliance with applicable emissions limits
- Engine/compressor planned startup/shutdown can be authorized as typical operations if shutdowns will emit < 4 lb/hr of natural gas emissions and subsequent startup emissions are controlled to a minimum of 98% efficiency for VOC and H<sub>2</sub>S

# MSS



- MSS requiring emissions quantification and recordkeeping:
- alternate operational scenarios or redirection of vent streams
  - pigging, purging, and blowdowns
  - temporary facilities if used for degassing or purging of tanks, vessels, or other facilities
  - degassing or purging of tanks, vessels, or other facilities
  - management of sludge from pits, ponds, sumps, and water conveyances

# MSS



MSS activities requiring only recordkeeping:

- routine engine component maintenance
- boiler refractory replacements and cleanings
- heater and heat exchanger cleanings
- turbine hot section swaps
- pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens

# Records



- Detailed production records
- Site specific/representative laboratory analysis
- Accurate and detailed plot plan
- Maintenance plan
- Other sampling and monitoring records for demonstrations of compliance for optional controls or methods used for emission reductions

# Representative Analysis



- Same field or reservoir
- Within 5 miles of sampled location
- Within 2 degrees of API gravity
- Same operational type (oil, wet gas, dry gas)
- Separation  $\pm 25$  psi,  $\pm 50^{\circ}\text{C}$

# Resources



February 18, 2011: Implementation of New Oil and Gas Permit by Rule and Standard Permit for Oil and Gas Facilities

<http://www.tceq.texas.gov/permitting/air/announcements/nsr-announce-02-18-11.html>

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