New Source Performance Standards for Petroleum Refineries
Proposed Subpart J and Subpart Ja

Potential Impacts on Louisiana Refineries
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Presentation Outline

- Review of existing Subpart J standards
- Proposed Subpart J revisions
- Proposed Subpart Ja standards
- Significant issues and concerns with proposal
- Louisiana refinery impacts
Existing Subpart J

- **Affected sources**
  - FCCU catalyst regenerators
  - Fuel gas combustion devices
  - Claus sulfur recovery plants >20 LTD

- **Standards**
  - Particulate Matter
  - Carbon Monoxide
  - Sulfur Oxides
    - \( \text{SO}_2, \text{H}_2\text{S} \) and reduced sulfur compounds
Sub J FCCU Catalyst Regenerators

- **Particulate Matter standard**
  - 2.0 lb PM/ton coke burn-off and 30% opacity
  - Plus incremental 0.10 lb PM/MM BTU supplemental liquid or solid fuel, and

- **Carbon Monoxide standard**
  - 500 ppmv

- **Sulfur Dioxide (7-day rolling average)**
  - Add-on control: $\geq 90\%$ or $\leq 50$ ppmv, or
  - No add-on control: 20 lb/ton coke burn-off, or
  - Feed $\leq 0.30$ weight percent total sulfur
Sub J Fuel Gas Combustion and Claus Sulfur Recovery Plants

- Sulfur oxides standard only

- Fuel gas combustion devices
  - Fuel gas $\leq 160$ ppmv $\text{H}_2\text{S}$ or
  - Outlet $\text{SO}_2 \leq 20$ ppmv

- Claus Sulfur Recovery Plants
  - With incineration: $250$ ppmv $\text{SO}_2$
  - No incineration: $300$ ppmv reduced sulfur compounds and $10$ ppmv $\text{H}_2\text{S}$
Proposed Subpart J revisions

- Amend definitions
  - “fuel gas”
  - “Claus sulfur recovery plant” and associated definitions

- Exempt certain fuel gas streams from monitoring

- Revise coke burn rate equation

- Other miscellaneous technical corrections
Subpart Ja - Affected Sources

- Fluid catalytic cracking units
- Fluid coking units
- Sulfur recovery plants (SRP)
- Process heaters
- Other fuel gas combustion devices
- Fuel gas producing units
Sub Ja Fluid catalytic cracking units

- Affected source no longer the catalyst regenerator only
- PM and \(\text{SO}_2\) standards more stringent
- No opacity limit
- \(\text{NO}_x\) standard introduced
- CO standard same as Subpart J
PM standard – by Method 5
- 1.0 lb PM/ton coke burn-off (0.5 lb/1000 lb) or
- 0.020 gr/dscf

Sulfur Dioxide
- \( \leq 50 \text{ ppmv} \) 7-day rolling average and
- 25 ppmv 365-day rolling average

\( \text{NO}_x \) standard, 7-day rolling average
- 80 ppmv (may not apply to fluid coking units)

Carbon Monoxide standard
- 500 ppmv hourly average
Sub Ja Sulfur Recovery Plants

- **Sulfur Recovery Plants > 20 LTD**
  - ≤ 250 ppmv combined SO$_2$ and reduced sulfur compounds, 12-hour rolling average
  - ≤ 10 ppmv H$_2$S, 12-hour rolling average

- **Sulfur Recovery Plants ≤ 20 LTD**
  - ≤ 1% mass of sulfur recovered, combined SO$_2$ and reduced sulfur compounds, 12-hour rolling average
  - ≤ 10 ppmv H$_2$S, 12-hour rolling average
Sub Ja Process Heaters

- **SO₂ Standard**
  - Outlet SO₂ ≤ 20 ppmv, 3-hour rolling avg. and
  - Outlet SO₂ ≤ 8 ppmv, 365-day rolling avg.

- **OR**, for process heaters that combust only fuel gas but not from a coking unit
  - Fuel gas ≤ 160 ppmv H₂S, 3-hour rolling avg. and
  - Fuel gas ≤ 60 ppmv H₂S, 365-day rolling avg.

- **OR**, for process heaters that combust only fuel gas, mixed with or only from a coking unit
  - Fuel gas ≤ 160 ppmv TRS, 3-hour rolling avg. and
  - Fuel gas ≤ 60 ppmv TRS, 365-day rolling avg.

- **Heaters > 20 MM BTU/hr, NOₓ ≤ 80 ppmv, 24-hr avg.**
**Sub Ja Other Fuel Gas Combustion**

- **SO₂ Standard**
  - Outlet SO₂ ≤ 20 ppmv, 3-hour rolling avg. and
  - Outlet SO₂ ≤ 8 ppmv, 365-day rolling avg.

- **OR, for devices that do not combust fuel gas from a coking unit**
  - Fuel gas ≤ 160 ppmv H₂S, 3-hour rolling avg. and
  - Fuel gas ≤ 60 ppmv H₂S, 365-day rolling avg.

- **OR, for devices that combust fuel gas mixed with or only from a coking unit**
  - Fuel gas ≤ 160 ppmv TRS, 3-hour rolling avg. and
  - Fuel gas ≤ 60 ppmv TRS, 365-day rolling avg.
Sub Ja Fuel Gas Producing Units

- Shall not routinely release fuel gas to a flare
  - Exempt process upsets, relief valve discharges and emergency malfunctions

- Startup, shutdown, and malfunction plan
  - Cover FCCU, fluid coking units, sulfur recovery plants, amine treatment system, fuel process heaters and other gas combustion devices
  - Cover planned SS, malfunctions of amine treatment system or sulfur recovery plant
  - Requires root cause analysis of any exceedance, SSM or upset in excess of 500 lb/day SO₂

- Delayed coking units must depressure to 5 psig and vent to the fuel gas system
Significant Industry Concerns

- Cost effectiveness analyses are flawed
- Best demonstrated technology (BDT) findings are not supported
- Overlaps and conflicts with 114 Consent Decrees
- Technically infeasible and not cost effective for existing sources to meet Sub Ja if modified
- Could place existing Sub J affected sources out of compliance
Consent Decree Issues

- 80% U.S. refining capacity subject
  - 10 Louisiana refineries subject

- 85 of 105 FCCUs subject

- Cost effectiveness was not a standard for CDs

- Subpart Ja could affect these same sources
Fuel Gas Definition

- Industry supports revising definition to list exempt streams
- Additional streams should be listed as exempt
  - Not amenable to amine treatment
  - Not combusted to derive useful work or heat
Additional streams that are not fuel gas

- Process vent streams subject to 40 CFR 63.641 (RMACT);
- Vent streams from asphalt oxidizers;
- Sulfur pit vents;
- Caustic oxidizer vents;
- Storage tank degassing vapors, when preparing a storage tank for maintenance;
- Loading operations that vent to flare or other control device regulated by 40 CFR Part 60, Subpart XX; Gasoline Distribution MACT; 40 CFR Part 63, Subpart R;
- Hydrogen plant PSA purge gas;
- **Synthesis gas produced from petroleum coke**;
- Reformer catalyst regeneration streams;
- Pilot and purge gas;
- Product loading/unloading operations, e.g., gasoline, diesel, resid;
- Gases from wastewater collection and treatment operations;
- Soil vapor extraction and ground water remediation operations;
- Storage tank vapor sent to a flare, thermal oxidizer, or other VOC control device;
- Odorous vapor streams sent to a flare, thermal oxidizer or other odor control device; and
- Propane and butane loading and/or storage operations
- Sour water storage vapors
Fuel Gas Producing Units/Flaring

- Prohibition on “routine” flaring is too vague

- Fuel gas producing units as affected sources too broad

- Combustion of clean fuel gas in flares should not be prohibited
  - Assists in maintaining refinery gas balance

- No BDT and CE analysis to support adoption of this work practice as NSPS
FCCU PM Standard

- 0.5 lb/1000 lb coke burn not achievable or cost effective
  - Does not consider control equipment deterioration over life of equipment
  - Has not been demonstrated in practice with Method 5
  - More stringent than MACT, which could not be met by ESP alone

- Proposed Test Method 5 (condensable) not consistent
  - Should continue to use Method 5B and 5F (filterable)

- Cost effectiveness
  - Should consider incremental control from CD

- Recommendations
  - Apply Sub Ja only to newly constructed FCCUs
  - Standard must be supported by full BDT and CE analysis
  - Retain use of Method 5B and 5F
Process Heaters NO$_x$ standard

- NO$_x$ from process heaters should be regulated under other NSPS
  - Not refinery-specific units

- CEMS should not be required
  - Units, 100 MM BTU/hr should be exempt from continuous monitoring
  - Very stable operation therefore periodic stack testing is adequate

- Not cost effective in some cases
  - If firing fuel oil, need SCR to comply
  - Some heaters must be rebuilt to accommodate ULNB
Process heaters/fuel gas TRS standard

- TRS is not defined in the rule
  - Reduced sulfur compounds means H₂S, carbonyl sulfide and carbon disulfide

- Control technology has not been demonstrated for TRS
  - CE and BDT not supported

- Amine treater may preferentially remove H₂S

- Blending with natural gas would be required
Summary of Key Industry Positions

- Subpart Ja should apply to new constructed affected units only (FCUs, FCCUs)
- Units controlled under Consent Decree should be exempt from Subpart Ja
- Fuel gas producing units should not be affected sources
- “Routine flaring” work practice should be deleted
Summary of Key Industry Positions

- Fuel gas definition should be expanded to list additional streams
- FCCU PM standard should be based on Method 5B and 5F
- TRS fuel gas limit should be removed
- Process heaters NO\textsubscript{x} should not be regulated under Ja
- All standards must be supported by valid CE and BDT analyses
Potential Louisiana Impacts

- Uncertainty of requirements as refinery expansions and modification plans are being developed
- Changing affected source from FCCU catalyst regenerator to FCCU changes the applicability analysis
- Will NSPS apply retroactively?
- Will proposed NSPS affect BACT/LAER determinations?
- Will LDEQ mirror the proposed standards in the new SIP development?