To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Jack Gerard, API
Sent: Thur 1/4/2018 2:27:24 PM
Subject: Energy Policy New Year's Resolutions for Washington

Click to view this email in a browser

January 4, 2018

Dear Samantha,

In passing tax reform last month, Congress and the Trump administration set a course toward greater economic growth and increased U.S. competitiveness. Policymakers can continue on that path in 2018 by taking action to advance U.S. energy development – one of the major drivers of job growth and economic benefits for consumers.

Expand Energy Access: Natural gas and oil development is essential to the U.S. economy, supporting 10.3 million jobs across a range of industries and reducing costs for homes and businesses. And there's more where that came from. Accessing the wealth of energy resources located in offshore areas could generate hundreds of thousands of jobs and lead to production gains of more than a million barrels of oil equivalent per day – further reducing dependence on overseas energy. The Trump administration's new plan for offshore development could provide a welcome opportunity to bring safe energy development to new offshore areas.

Keep Competitive Electricity Markets: Natural gas is now the leading source for U.S. electricity generation, and its benefits are wide-ranging. Its reliability, affordability and environmental benefits (helping reduce carbon dioxide emissions in the power sector to near 30-year lows) have made it a fuel of choice for power plant operators. Proposals to alter electricity markets in ways that favor some fuel sources over others could disrupt the free-market competition that has worked so well for consumers. By maintaining a level playing field in electricity markets, policymakers in Washington and at the state level can protect consumers and ensure affordable, reliable and safe electricity for homes and businesses.

Capitalize on Energy Infrastructure Opportunities: Congress and the White House have pledged to make infrastructure a priority in 2018, and energy infrastructure offers exactly the job-creating, economy-strengthening opportunity they're looking for. Building pipelines and other infrastructure to keep pace with growing production could support up to 1,047,000 jobs each year on average through 2035 via shovel-ready projects that are not reliant on taxpayer dollars. Eighty-one percent of American voters support expanding U.S. energy infrastructure – making it an economic and political winner.

Cut Red Tape: States are currently saddled with the costly burden of complying with two dueling sets of ozone standards even though ground level ozone levels have decreased 17 percent since 2000. Legislation passed by the House would help provide regulatory certainty for states and businesses of all sizes while continuing to reduce ozone precursor emissions. Getting this sensible policy across the finish line should be a priority this year. Ethanol policy is also due for a rewrite. Without reform, the outdated Renewable Fuel Standard – which adds more ethanol to the nation's fuel supply each year, without fully taking market demand into account – threatens to cause engine damage and raise consumer costs. The RFS was mandated a decade ago to reduce costs and reliance on foreign energy – two goals since achieved by the U.S. energy revolution. It's time to acknowledge current realities and repeal or

significantly reform the RFS.

Not only do pro-energy policies make good economic sense, they receive bipartisan support. Eighty percent of U.S. voters support increased domestic oil and natural gas production. As Congress and the Trump administration set priorities for 2018, pro-economy, pro-consumer energy policies should be on the short list.

Sincerely,

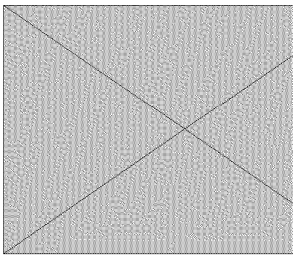
Jack N. Gerard
President & CEO
API

Offshore Energy: Safe Development for a Secure Energy Future

The natural gas and oil industry has the experience and advanced technology to safely develop the nation's offshore reserves, and we've worked together with regulators to make offshore development safer than ever. Learn more about the importance of offshore energy to future U.S. energy security, and the steps we've taken to keep offshore development safe.

Follow our Blog to stay up-to-date

To stay up-to-date on the latest energy-related news, there is no better place to check than the Energy Tomorrow Blog.



About API:

API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 40 million Americans.

To learn more about API and the value of oil and natural gas, please visit API.org.

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Jack Gerard, API
1220 L Street, NW
Washington, DC 20005
US

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: ECOS
Sent: Fri 12/22/2017 4:34:41 PM
Importance: Normal
Subject: ECOS Leaders Meet in Washington to Advance Cooperative Federalism, Congress Funds Government thru Mid-January, & More
Received: Fri 12/22/2017 4:35:50 PM

ECOSWIRE

Friday, December 22, 2017

Vol. 19 No. 47

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ECOS will not be published on December 29 and will resume publication January 5. From all the ECOS staff, best wishes for the holidays and New Year!

ECOS Leaders Advance Discussions with U.S. EPA on Cooperative Federalism and More

This week ECOS President Todd Parfitt of Wyoming, Vice President Becky Keogh of Arkansas, Secretary-Treasurer Jim Macy of Nebraska, and ERIS President David Paylor of Virginia conducted visits with U.S. EPA officials in Washington, DC, to continue conversations around oversight of delegated programs and advancing Cooperative Federalism 2.0. The ECOS leaders met with Henry Darwin, Deputy Assistant Administrator and Chief of Operations, and officials in the U.S. EPA Offices of Air and Radiation and Enforcement and Compliance Assurance.

The leadership also spent time on the search process for a new ECOS/ERIS Executive Director. The members' commitment to the organizations agendas at this busy time of year is sincerely appreciated. [Dunn]

From left to right: Todd Parfitt (WY), Becky Keogh (AR), Susan Bodine (U.S. EPA OECA), David Paylor (VA), and Jim Macy (NE).

Congress Funds Government through Mid-January

On December 20, Congress passed a Continuing Resolution (CR) to fund the federal government through January 19, 2018. The third CR in the FY 2018 budget cycle, this bill maintains FY17 spending levels, albeit with some budget anomalies associated with various policy riders. The bill is expected to be signed by President Trump before the current CR expires at midnight Friday.

With lawmakers imminently heading home for the holiday recess, negotiations will resume in January on overall spending caps as well as several unrelated issues expected to be rolled into the budget debate. [McAleer]

U.S. EPA Announces Next Steps Following Proposed CPP Repeal

U.S. EPA on December 18 issued an Advance Notice of Proposed Rulemaking (ANPRM) indicating that the agency will solicit public input as it considers the next regulatory steps to limit greenhouse gas emissions from existing electric utility generating units (EGUs), also known as power plants.

The ANPRM is a separate, but related, action to the October 16 proposal to repeal the Clean Power Plan. It offers the public the opportunity to comment on specific topics for the agency to consider in developing any subsequent proposed rule. EPA is specifically soliciting information on systems of emission reduction for EGU facilities, compliance measures, and state planning requirements under Clean Air Act section 111(d).

EPA will take comment on the ANPRM for 60 days following publication in the *Federal Register*. More information, including the ANPRM and fact sheet, are available here. [Poole]

ECOS and Other State Media Associations Co-Sign Letter on VIDA

ECOS and three other nonprofit associations representing state environmental regulatory agencies (the Association of Clean

Water Administrators [ACWA], the Association of State Wetland Managers [ASWM], and and the Association of Fish and Wildlife Agencies [AFWA]) co-signed a letter to members of Congress this week detailing the potential consequences for environmental quality if the Vessel Incidental Discharge Act (S. 1129) were enacted. The associations previously wrote a letter of concern on VIDA in June 2016.

Read this week's letter here. [Longsworth]

U.S. EPA Finalizes e-Manifest User Fee Rule

U.S. EPA on December 20 finalized its rule for setting and revising fees for users of the e-Manifest system. This final e-Manifest User Fee Rule completes the regulatory framework for implementing Congress' *Hazardous Waste Electronic Manifest Establishment Act of 2012*, which authorizes EPA to implement a national system and collect user fees to recover the costs of developing and operating the system.

Click here for more information about the final e-Manifest User Fee Rule, including the pre-publication version.

For additional information, join EPA for the next e-Manifest webinar on **January 3 at 2-3:30 p.m. Eastern** by accessing the live webinar here. [Parisien]

Former U.S. EPA Acting Administrator McCabe Tapped to Head New Jersey DEP

New Jersey Governor-Elect Phil Murphy on December 20 announced his selection of former U.S. EPA Acting Administrator Catherine McCabe to serve as Commissioner of the state Department of Environmental Protection. She will succeed Bob Martin in the post.

Among McCabe's previous positions are Deputy Regional Administrator of EPA's Region 2 and Deputy Chief of the U.S. Department of Justice Environmental Enforcement Section. ECOS looks forward to welcoming her as a member! [Parisien]

Ehm Selected as Executive Committee Region 7 Representative

ECOS is pleased to announce that Bill Ehm of Iowa has been selected by his regional colleagues to serve as Region 7 Representative to the Executive Committee. Ehm fills the unexpired term of Jim Macy, who was elected Secretary-Treasurer earlier this year.

Ehm's term is effective through the 2018 Fall Meeting, with the option for renewal for a full two-year term. [Swanson]

Bill Ehm of Iowa

Cross Off Spring Meeting Registration and Reservations from Your Holiday To Do List

ECOS' elves are already hard at work planning a timely and wide-ranging Spring Meeting on *Getting to Results*. The gathering, to be held March 20-22 ECOS Spring Meeting in St. Paul, Minnesota, will spotlight ECOS' expanding Results.org effort, as well as state initiatives to accelerate and enhance land cleanups, promote cross-agency partnerships, ensure a secure and sustainable energy future, encourage Sustainable Materials Management, achieve tangible results through Cooperative Federalism 2.0 and E-Enterprise, tackle PFAS, and effectively communicate progress to the public.

Also planned are keynotes by Governor Mark Dayton of Minnesota (invited) and a generational expert on building for future agency success, a point-counterpoint session on Clean Water Action 404 assumption, and two offsite evening events including an excursion to the Science Museum of Minnesota.

Register by **February 16** to receive the reduced early bird rate. Also, act now to reserve a room at the hotel by calling The Saint Paul Hotel at (800) 292-9292, and mention the ECOS Spring Meeting to receive the group rate. The special ECOS group rates of $149 (government and staff room) and $169 (deluxe room) plus tax are available until February 19 or sellout of the room block, whichever is sooner. ECOS room nights include March 19, 20, and 21, with limited availability March 22. Visit the Spring Meeting page for additional details.

For agenda or sponsorship information, please contact Lia Parisien of ECOS. Contact Sarah Grace Longsworth for registration information and Megan Swanson for hotel information. [Parisien]

State News You Can Use

New Mexico Develops Streamlined Oil and Gas Air Emissions Application

Ohio EPA Announces 2018 Water Pollution Control Loan Fund Program Management Plan

Mississippi Offers Tips to Promote a Green Holiday Season

Need-to-Know News in Compliance and Enforcement, Air, & Water

U.S. EPA Delays FY17 Data Verification, Plans Webinar on Verification Tool and Improvements

Area of Focus: *Compliance and Enforcement*

This week, ECOS shared with members a letter from U.S. EPA's Office of Enforcement and Compliance Assurance (OECA) announcing a delay in the timing of the FY2017 data verification period to allow states time to review changes to the metrics and measures for the State Review Framework Round 4.

The letter also announces a national webinar on **January 16, 2018 at 3-4:15 p.m. Eastern** regarding data verification and improvements EPA has made to its tool that states use to complete their verification process. States may register here.

For more information, contact Rebecca Kane of OECA. [Graves]

Court Orders U.S. EPA to Set Timetable for Ozone Designations

Area of Focus: *Air*

On December 20, the U.S. Court of Appeals for the DC Circuit ordered U.S. EPA to act by **January 12** to set a firm date and outline a compliance timetable for remaining attainment designations for the 2015 ground-level ozone standard.

All designations were due October 1. U.S. EPA formally published designations for areas of the country in attainment on November 16. The final decisions for areas likely out of compliance have not been released.

In June 2017, EPA Administrator Scott Pruitt announced a one-year extension that would have pushed back the deadline for all attainment designations until October 2018. This extension was withdrawn in August 2017. For enforcement purposes, the attainment designations start the clock for states that must draft cleanup plans for areas that are out of compliance. [Poole]

U.S. EPA Launches Water System Partnerships Website

Area of Focus: *Water*

U.S. EPA has launched a new interactive website to promote awareness of the benefits of drinking water partnerships. For communities and utilities facing growing costs and challenges for treating drinking water, drinking water system partnerships provide opportunities to increase capacity, share costs, and leverage other resources.

The new website highlights ways partnerships can address these challenges, enhancing public health by working together and sharing information through a user-friendly interface accessible to states, communities, utilities, and others. [Piper]

U.S. EPA Appointments

Stepp Moving From Region 5 to Helm of Region 7

U.S. EPA Administrator Scott Pruitt on December 19 announced the appointment of former ECOS member Cathy Stepp to become Regional Administrator for Region 5.

Stepp currently serves as Principal Deputy Regional Administrator for Region 7 and will return to the Midwest region, where

was Secretary of the Wisconsin Department of Natural Resources from 2011 to 2017. Stepp also previously served as a Wisconsin State Senator. [Parisien]

ECOS Staff News

Graves Promoted to Executive Project Manager

ECOS congratulates Beth Graves on her recent promotion to the position of Executive Project Manager!

Graves, who has worked for the association for a decade, spearheads work conducted under the E-Enterprise for the Environment initiative and the ECOS Planning Committee. [Parisien]

Opportunities

Reminder: State Communications Leads Sought for New ECOS Community of Practice

ECOS invites all members to provide the contact information for their agency's lead communications expert to become part of our new Communications Community of Practice. In accordance with ECOS President Todd Parfitt's 2017-2018 priorities, ECOS is launching this virtual learning community for state communications professionals to share best practices, success stories, challenges, and transferable lessons.

It is anticipated that once all contacts are identified, the group may hold three calls per year and also use one another as resources to share questions and information. The group also will periodically interface with U.S. EPA communications leads from Headquarters and the Regions.

Contact information for your state expert may be sent to Nia Duke of ECOS. [Duke]

U.S. EPA Invites Nominations to National Advisory Council for Environmental Policy and Technology

U.S. EPA is seeking nominees to fill several potential vacancies on the National Advisory Council for Environmental Policy and Technology (NACEPT). Representatives of state, local, and tribal governments, academia, industry, and nongovernmental organizations serve on this federal advisory committee.

NACEPT provides advice to the EPA Administrator on a range of policy, management, and technology issues.

For more information, including how to apply, refer to the *Federal Register* notice. The deadline for applications is **January 3, 2018**. [Hanson]

U.S. EPA Seeks Nominations to Commission for Environmental Cooperation

Committee

U.S. EPA invites nominations for appointment to the Governmental Advisory Committee to advise the U.S. Representative to the Commission for Environmental Cooperation.

Nominees are sought by **February 16, 2018** from the state, local, and tribal government sectors. For more information, click here. [Parisien]

Upcoming Events

Webinars

ITRC on Remedy Selection for Contaminated Sediments

The Interstate Technology & Regulatory Council (ITRC) will hold its first online training of 2018 on *Remedy Selection for Contaminated Sediments* on **January 9, 2018 at 1-3:15 p.m. Eastern.**

The sediments underlying many of our nation's major waterways are contaminated with toxic pollutants from past industrial activities. Cleaning up contaminated sediments is expensive and technically challenging. Sediment sites are unique and complex, and require a multidisciplinary approach and often project managers lack sediments experience. This training course will teach participants to apply the associated ITRC technical and regulatory guidance as a tool to overcome the remedial challenges posed by contaminated sediment sites.

Learn more and register here. [Bodi]

Exchange Network on Grant Applications

In support of the FY 2018 Exchange Network (EN) Grant cycle, U.S. EPA is hosting webinars to assist interested applicants. The final webinar will be held **January 10, 2018 at 1-2 p.m. Eastern**. Topics will include a summary of the FY 2018 EN Grant program, new and modified solicitation notice content, administrative procedures for submitting applications, tips on writing a high-quality application, and a question-and-answer session for potential applicants.

To participate, call (866) 299-3188 and use conference code 2025660466#, and access this webinar link. An Adobe Connect account is not required to enter the webinar, and participants can simply log in as a guest.

For more information, please contact EPA's Salena Reynolds. [McAleer]

ECOS and U.S. EPA on ECHO

An E-Enterprise ECHO team led by Oklahoma and EPA has identified potential improvements to the display, usability, and accuracy of U.S. EPA's Enforcement and Compliance History Online (ECHO) website. The team has identified a number of possible enhancements to improve the user experience and the display of facility compliance history.

Two identical webinars were planned to share the proposed changes with the co-regulator community and receive

feedback. The first was held on December 12, and a second webinar will repeat the same content on **January 11, 2018 at 12-2 p.m. Eastern**. Please register here.

In advance of the webinars, states can learn more about the proposed changes in this summary document. Please note that the changes are proposals only at this point and the team is seeking comments and input to ensure that proposed changes will meet the needs of ECHO stakeholders. You may send general written comments, questions, and markup of the summary document to Layne Piper of ECOS.

Oklahoma, as state team lead, asks states to provide input on a very brief set of questions to help the team better understand the ECHO community's preferences for a specific set of display and labeling options. Please click here by **January 26** to participate. [Piper]

NEWMOA and NERC on C&D Materials Management & Markets in the Northeast

The Northeast Waste Management Officials Association (NEWMOA) and Northeast Recycling Council (NERC) will host a webinar on Construction & Demolition (C&D) Materials Management and Markets in the Northeast on **January 17, 2018 at 2-3:30 p.m. Eastern**.

The discussion will center on two main areas:

- The results of NEWMOA's recently released analysis of data collected by the environmental agencies in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont on architectural C&D materials disposal, processing, and recovery for reuse and recycling.
- The results of a Massachusetts Department of Environmental Protection (MassDEP) funded study that evaluated the current and future status of C&D debris management in Massachusetts, and identified and recommended potential opportunities for the diversion of a greater proportion of recyclable materials to recycling markets. NERC administered and contracted with DSM Environmental Services to conduct the project. MassDEP has established a goal of diverting 50 percent of C&D materials from disposal, but in recent years the actual diversion rate has plateaued at around 30 percent. The primary objective of the analysis undertaken by DSM was to first assess incoming and outgoing materials at Massachusetts C&D processors and handling facilities, and to determine what the opportunities and constraints are to increase materials diversion beyond 30 percent.

Register for the webinar here. Please reach out to Connor MacCartney with any questions.
[MacCartney]

U.S. EPA on Urban Soil Contamination

U.S. EPA will hold its first Tools and Resources webinar of the New Year on **January 17, 2018 at 3-4 p.m. Eastern**. The webinar will focus on identifying sources (site-related or natural, anthropogenic) of soil contamination in urban settings, a process vital to decision-making during environmental cleanups.

Presenters will discuss EPA's methodology for citywide or urban area background data set collection, as well as results of a recent U.S. EPA study on soil contamination in Louisville and Lexington, Kentucky; Memphis and Chattanooga, Tennessee;

Raleigh and Winston-Salem, North Carolina; and Gainesville, Florida.

To register, click here. [Longsworth]

ECOS on 2018 Clean Water SRF

On **January 30, 2018 at 2-3:30 p.m. Eastern**, ECOS will host a webinar to highlight three states' innovative uses of Clean Water State Revolving Funds (CWSRF). The three featured projects demonstrate unique uses and dispersion of CWSRF funds, and offer valuable case studies that will build state capacity and knowledge.

See this flyer for more information on the presentations from Idaho, Iowa, and Massachusetts. The webinar is the product of a research project to document the flexibilities of the CWSRF. ECOS is working under a cooperative agreement with U.S. EPA's Office of Water.

Register here for the webinar, or contact Layne Piper for more information. [Piper]

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Ross Eisenberg
Sent: Mon 6/26/2017 3:49:59 PM
Subject: Re: Ozone

No problem. Here you go: lwilk@nam.org

[redacted]

Hey Ross can you shoot me Lauren Airey's work email address?

Sent from my iPhone

On Jun 6, 2017, at 9:25 PM, Ross Eisenberg <REisenberg@nam.org> wrote:

> This just went up from NAM on today's announcement:
>
> http://www.shopfloor.org/2017/06/epa-grants-states-much-needed-flexibility-ozone-standard/

To: Dravis, Samantha[dravis.samantha@epa.gov]
Cc: Amanda France[Amanda.France@cei.org]
From: Kent Lassman
Sent: Tue 10/3/2017 3:39:42 PM
Subject: Three quick ideas.

Sam

1. Per discussion, please see below for an interesting take on the 2015 NAAQS issue. Let me know if you'd like to discuss.

2. Please reiterate the core of our conversation from Friday and what I said to Mr. Pruitt yesterday at the White House, I'm committed to a constructive role for CEI.

3. Who should I contact about scheduling a sit-down among our policy guys and the various policy folks from EPA? I can drive the process if you point me toward the correct contact.

Good to see you yesterday. Best,

Kent

From:
Sent: Monday, October 2, 2017 3:24 PM
To: Kent Lassman
Subject:

As discussed: On the question of a legal basis for re-opening the 2015 NAAQS:

From:
Sent: Monday, October 2, 2017 12:33 PM
To:
Subject: answers to your ozone question

They [EPA] can simply reconsider the rule, as they would any regulation. There's no statutory prohibition on it, and, indeed, it's exactly what the Obama administration did when it first tried to revise the 3/2008 Bush ozone NAAQS. See discussion on pages 6-7 of this FR notice https://www.gpo.gov/fdsys/pkg/FR-2010-01-19/pdf/2010-340.pdf#page=1 .

The 2015 ozone standards were done a year past due, but I don't think there was any enviro litigation that lead to a court ordered deadline. The upshot is that I think there's the space to do this, if there's the political will.

As for a rationale, the EPA should argue that it has never fulfilled its non-discretionary duty under Clean Air Act section 109(d)(1)(C) to receive advise [sic] from CASAC regarding both background concentrations of ozone and the social/economic effects of the NAAQS rule.

I don't think the reconsideration of the rule would suffice as a legal justification to delay implementation of the 2015 ozone naaqs beyond the ~22 months in extensions that are provided for in the act (between the administrator's and governor's authority). BUT IT MIGHT! There's no case law here.

So I'd announce the rule is being reconsidered, based primarily on comments submitted by western governors that allege the 2015 rule unreasonably accounts for background ozone. And, then I'd get cracking on putting together CASAC panel under 109(d)(1)(C). And then, if it's done w/in ~2 years, I'd issue a reconsidered rule and defend it before the courts, where CASAC's advice will carry a lot of weight.

Best,

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: ECOS
Sent: Fri 11/3/2017 6:08:41 PM
Importance: Normal
Subject: Parfitt Advances ECOS Priorities in DC, ECOS Weighs in on U.S. EPA Strategic Plan, & More
Received: Fri 11/3/2017 6:10:02 PM

ECOSWIRE

Friday, November 3, 2017

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ECOS President Advances State Priorities across Nation's Capital

This week, Todd Parfitt of Wyoming and ECOS staff participated in a series of meetings to share Parfitt's priorities as ECOS President and information on Cooperative Federalism 2.0 and ECOSResults.org. Parfitt met with the White House Office of Management and Budget on the outlook for state and tribal assistance grants and ECOS' budget priorities generally. Walking the halls of the U.S. Capitol, Parfitt met with Senate Environment & Public Works Committee Chair John Barrasso

(R-WY) and Rep. Liz Cheney (R-WY).

Other key meetings included discussions with EPA officials on the new Smart Sectors Program and permitting reform (see related story), and a gathering with the Executive Directors of the Association of Clean Water Administrators and Association of State Wetland Managers on advancing state assumption of the Section 404 program (see related ECOS Resolution). [Dunn/Swanson]

ECOS Expresses Support for Cooperative Federalism, E-Enterprise in U.S. EPA Strategic Plan Comments

ECOS on October 31 submitted comments on the U.S. EPA's draft FY 2018-2022 Strategic Plan. In the comment letter, ECOS offers support for the draft plan's emphasis on cooperative federalism and E-Enterprise for the Environment and suggests additional areas for agency focus, such as emergency response. The letter is accompanied by several pages of technical input on various aspects of the strategic plan.

The draft plan was released October 5 for public comment. Over the course of the 26-day public comment period, ECOS held discussions on the draft through an all-member call and correspondence and submissions from individual states.

Stay tuned for a final version of the strategic plan later this year. [McAleer]

Pruitt Announces Directive on Agency's Science Committees

On October 31, U.S. EPA Administrator Scott Pruitt issued a directive designed to ensure "independence and integrity" of agency Federal Advisory Committees (FACs). The new policy requires all FAC members to be independent from EPA and will prevent any individual who receives EPA funding from serving on one of the agency's FACs. This principle would not apply to state, tribal, or local government agency recipients of EPA grants.

The directive focuses on the following areas related to FACs: strengthening member independence; increasing state, tribal and local government participation; enhancing geographic diversity; and promoting fresh perspectives.

In addition, Pruitt announced key leadership appointments for three of the 23 committees: Michael Honeycutt of the Texas Commission on Environmental Quality will chair the Science Advisory Board; Tony Cox of Cox Associates will head the Clean Air Scientific Advisory Committee; and Paul Gilman of Covanta will serve as Chairman of the Board of Scientific Counselors. In the coming days, the full membership of these committees and boards will be announced and is expected to include state environmental agency science experts. [Swanson]

U.S. EPA Seeks Comments on Applying Federal Permitting Best Practices to State Infrastructure Permits

On October 31, EPA issued a *Federal Register* notice seeking comments on whether federal permitting best practices are generally applicable to infrastructure permits issued by delegated or authorized states as described in Title 41 of the Fixing America's Surface Transportation Act (FAST-41).

Federal "best practices" specifically refers to the January 18 document *Recommended Best Practices for Environmental Reviews and Authorizations for Infrastructure Projects* developed by the Federal Permitting Improvement Steering Council. The document includes the following best practice areas: enhancing early stakeholder engagement; ensuring timely decisions regarding environmental reviews (including exploring opportunities to expand use of general permits where appropriate); improving coordination between federal, state, and tribal agencies; increasing transparency; reducing administrative burdens by using online permit applications, eliminating unnecessary internal process steps, and conducting routine evaluations of permit processes; using geographic information systems (GIS) to expedite permitting; creating and providing training; and implementing other best practices such as use of conflict resolution and third-party neutral facilitators.

Comments are due **November 20**. States are asked to share feedback on the best practices with Beth Graves of ECOS. [Graves]

House Looks at Hurricane Response Takeaways in Two Hearings this Week

This week, the House Committee on Transportation and Infrastructure held a hearing to "explore key takeaways from this year's unprecedented hurricane season." One of the witnesses was new U.S. EPA Region 2 Administrator Pete Lopez.

Also this week, the House Committee on Energy and Commerce Subcommittee on Energy held a hearing entitled *The 2017 Hurricane Season: A Review of Emergency Response and Energy Infrastructure Recovery Efforts*. This hearing featured witnesses from the U.S. Department of Energy and U.S. Army Corps of Engineers. [Dunn]

State News You Can Use

Louisiana, U.S. EPA, and DOJ Reach Air Pollution Settlement with ExxonMobil

Colorado, U.S. EPA, and Justice Department Reach Air Pact with PDC Energy

Missouri Accepting Comments on Reducing Red Tape

Wyoming Works with U.S. EPA to Protect Streams

Virginia Reports Cleanest Air in Past 20 Years

Arkansas Staff Get 'Groovy' at Arkansas Environmental Federation Convention

Maine Announces Governor's Awards for Environmental Excellence

ECOS Resource of the Week

ITRC's Guidance on Complex Sites

Does your state agency use resources from the Interstate Technology and Regulatory Council (ITRC)? One such resource is its latest guidance document, *Remediation Management of Complex Sites*, released this week.

This guidance presents a recommended process for remediation management at complex sites, incorporating and referring to best management practices, tools, and technologies described in previous publications by U.S. EPA, the U.S. Department of Defense, ITRC, and others. The guidance also includes numerous case studies that describe real-world applications of remediation and remediation management at complex sites.

Click here to view the document. ITRC will hold its first Complex Sites online training class on **February 6, 2018 at 1-3:15 p.m. Eastern**.

ITRC is a state-led coalition of state and federal regulators, industry, and stakeholders working together to achieve regulatory acceptance of environmental technologies. Its website can be accessed at the bottom of ECOS' homepage, or here. [Bodi/Longsworth]

Need-to-Know News in Air, Water, & Environmental Justice

U.S. EPA Sets Public Hearing on CPP Repeal

Area of Focus: *Air*

U.S. EPA has announced that it will hold a public hearing on the proposed repeal of the *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (commonly known as the Clean Power Plan, or CPP) in Charleston, West Virginia on **November 28-29**. Registration will be open once the public meeting notice is published in the *Federal Register*, and all individuals wishing to speak are encouraged to register in advance.

"EPA is headed to the heart of coal country to hear from those most impacted by the CPP and get their comments on the proposed Repeal Rule," said EPA Administrator Scott Pruitt.

For additional details, see the EPA press release and EPA website for background information on the CPP. [Poole]

U.S. EPA Issues Pair of Actions on Cross-State Air Pollution

Area of Focus: *Air*

U.S. EPA on October 30 announced two actions that address cross-state air pollution for the 2008 ozone standards.

One action denies a petition filed by nine northeastern states under Section 176A of the Clean Air Act asking the agency to add eight states plus portions of Virginia to the Ozone Transport Region. EPA has determined that approaches such as those under the Clean Air Act's (CAA's) good neighbor provision will be more effective in addressing remaining ozone transport obligations for the 2008 standards. More information is available here.

In the second action, EPA issued a memo to provide supplemental information to states and the Regions. This information supports the development or review of State Implementation Plans that address the CAA's "good neighbor" provision, as it pertains to the 2008 ozone National Ambient Air Quality Standards. While this information can inform the development of these plans, the information is not a final determination regarding states' remaining obligations under the good neighbor provision, and any such determination would be made through notice-and-comment rulemaking. More information is available here. [Parisien]

U.S. EPA Signs NODA for Proposed Stays of Oil and Gas Air Rules

Area of Focus: *Air*

On November 1, U.S. EPA signed two Notices of Data Availability (NODAs) related to the agency's proposed stays of air requirements in the 2016 New Source Performance Standards for the oil and natural gas industry. EPA on June 16 had proposed a two-year stay and a three-month stay of the rule's fugitive emissions requirements, well site pneumatic pump standards, and requirements that closed vent systems be certified by a professional engineer while the agency reconsiders issues associated with these requirements.

Since proposing the stays, the agency has heard a wide range of concerns and suggestions from stakeholders both about the 2016 rule and the proposed stays. The NODAs provide information on some of these issues and seek comments to assist in developing a final rule. The information provided in the NODAs falls into two categories: challenges to implementing the requirements in the 2016 rule that would be covered by proposed stays; and the agency's legal authority to issue a stay. EPA also is providing an updated analysis of cost savings, forgone benefits, and net benefits of the proposed two-year stay.

EPA will take public comment on the NODAs for 30 days following publication in the *Federal Register*. For more information, click here. [Parisien]

U.S. EPA Recognizes 28 CWSRF Program Successes

Area of Focus: *Water*

U.S. EPA on October 31 recognized 28 clean water infrastructure projects for excellence and innovation within the Clean Water State Revolving Fund (CWSRF) program at the 2017 National SRF Workshop hosted in Indianapolis, Indiana by the Council of Infrastructure Financing Authorities. Honored projects range from large wastewater infrastructure projects to small decentralized and agriculture projects.

EPA's Performance and Innovation in the SRF Creating Environmental Success (PISCES) program celebrates innovation

demonstrated by CWSRF programs and assistance recipients. The CWSRF is a federal-state partnership that provides communities a permanent, independent source of low-cost financing for a wide range of water quality infrastructure projects. Over the past 30 years, CWSRF programs have provided more than $125 billion in financing for water quality infrastructure.

"For decades the Clean Water State Revolving Fund has supported critical water infrastructure projects that help grow the American economy and support our way of life," said Mike Shapiro, Acting Assistant Administrator for EPA's Office of Water. "These projects are a testament to the power of the Clean Water State Revolving Fund in leveraging investment to meet the country's diverse clean water needs."

More about the projects and the PISCES program can be found here. Information about an ECOS project to identify and share innovative CWSRF work can be found here. [Parisien/Piper]

U.S. EPA Announces Selections for 2017 Environmental Justice Small Grants

Area of Focus: Environmental Justice

U.S. EPA has announced the award of nearly $1.2 million in competitive grants to 36 community and tribal organizations working to address environmental justice issues in their communities. The grants enable these organizations to conduct research, provide education, and develop community-driven solutions to local health and environmental issues in minority, low-income, and tribal communities.

In an effort to increase outreach to affected communities in states and territories, the 2017 Environmental Justice Small Grants (EJSG) Program placed special emphasis on proposals from under-represented states that have been awarded three or fewer EJSGs over the last five years. Of the 36 total projects selected, 23 are from underrepresented states (64%). The agency will make final awards upon successful completion of the award application process. [Poole]

E-Enterprise for the Environment

E-Enterprise

McDonnell Appointed to E-Enterprise Leadership Council

This week, ECOS President Todd Parfitt of Wyoming appointed Pennsylvania Department of Environmental Protection Secretary Patrick McDonnell to serve on the E-Enterprise Leadership Council (EELC). McDonnell fills the state EELC vacancy created when John Stine of Minnesota ended his term as ECOS President.

ECOS thanks Stine for his EELC service and welcomes McDonnell to the leadership body. [Graves]

Member News

Tormey of Iowa Elected to ACOEL Fellowship

Congratulations to Ed Tormey, General Counsel of the Iowa Department of Natural Resources, on his election last week as a Fellow of the American College of Environmental Lawyers (ACOEL). Tormey has practiced environmental law in both the private and public sectors for 27 years and also has served as Legal Services Bureau Chief at the Ohio Environmental Protection Agency.

As reported in last week's *ECOSWIRE*, former ECOS member and President Tom Burack also was one of 20 individuals from across the nation elected last week to the College Fellowship at ACOEL's 10th anniversary meeting in Charleston, South Carolina. [Parisien]

Career Opportunities

ECOS Seeks Project Manager

ECOS is accepting applications for a Project Manager to support the work of E-Enterprise for the Environment (EE) and the National Environmental Information Exchange Network (EN). The Project Manager works with senior staff at state environmental agencies, U.S. EPA, and tribes to support the operation of the EN, and to facilitate its deeply connected and formative role in EE.

To apply for this position, send a resume and cover letter here by November 30 with subject "Application for Project Manager."

See more information here. [Longsworth]

Upcoming Events

Meetings

Butler of Ohio to Participate in Disaster and Public Safety Brown Bag on the Hill

The Sea Grant Association invites interested attendees to a lunchtime briefing, *Using Science and Outreach to Assist State and Local Decision Makers in Disaster Preparedness and Public Safety*. ECOS member Craig Butler of Ohio will participate in the lunchtime discussion, which is sponsored by Congressmen Lee Zeldin of New York and Joe Courtney of Connecticut.

The event will be held **November 8 at 12-1:30 p.m.** in the Rayburn House Office Building. RSVP by November 3 to Joel Widder. [Piper]

ECOS Calls

November, December All-Member Calls

ECOS will hold its remaining two All-Member Monthly Calls in 2017 on:

- **November 16, 4-5 p.m. Eastern** on science and research
- **December 14, 3-4 p.m. Eastern** on data and analytics

Please mark your calendars now. An agenda with dial-in information will be emailed to all ECOS members prior to the call. [Swanson]

Superfund Workgroup

The ECOS Superfund Workgroup will hold its next call on **November 27 at 2:30-3:30 p.m. Eastern** to continue state-U.S. EPA discussion of implementing the recommendations of the EPA Superfund Task Force. The workgroup is chaired by ECOS Waste Committee Chair Scott Thompson, Director of the Oklahoma Department of Environmental Quality, and has the regular participation of EPA Task Force Chair Kell Kelly, Senior Advisor to the Administrator, and other EPA leaders.

The call will include a report-out on Superfund discussions at the recent ASTSWMO Annual Meeting by ASTSWMO CERCLA/Brownfields Subcommittee Chair Amy Brittain of Oklahoma and former ASTSWMO Past President Bonnie Buthker of Ohio. Call participants will provide input on the solutions proposed.

For more information, please contact Lia Parisien of ECOS. [Parisien]

Shale Gas Caucus

The ECOS Shale Gas Caucus (SGC) will kick off its Phase 3 cross-media webinar series on **December 6 at 2-3 p.m. Eastern** with a discussion of preventing produced water spills and leaks. Moderated by SGC Co-Chairs Dave Glatt of North Dakota and Martha Rudolph of Colorado, the call will feature Scott Anderson and Dan Mueller of the Environmental Defense Fund and Roy Hartstein of Southwestern Energy. Jim Kenney of U.S. EPA's Office of Enforcement and Compliance Assurance will follow with an announcement of an SGC success story in the area of produced water.

For more information, please contact Lia Parisien of ECOS. [Parisien]

Webinars

California on Safer Consumer Products

California's Department of Toxic Substances Control (DTSC) will hold a Safer Consumer Products program public workshop on lead-acid batteries and alternatives on **November 6** in Sacramento, California. The event will be broadcast via webinar and will cover the various uses of lead-acid batteries, the regulatory landscape they face, lithium-iron-phosphate batteries as a potential alternative in vehicles, automobile manufacturer perspectives, and issues such as recycling.

This information is being gathered as part of DTSC's work to evaluate whether lead-acid batteries should be listed as a Priority Product under California's Safer Consumer Products regulations. Public comments and questions are welcome.

Register for the in-person or webinar and download the agenda and event announcement. [Longsworth]

U.S. EPA and the Army Corps on WOTUS by Sector

U.S. EPA and the U.S. Army Corps of Engineers have announced ten teleconferences to hear from stakeholders their recommendations for revising the definition of "Waters of the United States" under the Clean Water Act. The first nine teleconferences will be tailored to specific industries, as follows, and the tenth will be open to the public at large.

The teleconferences will run throughout the fall on **Tuesdays at 1-3 p.m. Eastern** as follows:

- **November 7** scientific organizations and academia;
- **November 14** stormwater, wastewater management and drinking water agencies; and
- **November 21** general public. [Piper]

ECOS and U.S. EPA on Compliance Research Part 5

Part 5 of the Compliance Research Webinar Series entitled *Innovative Approaches to Foster Compliance – the Role of Deterrence* will be held on **November 9 at 1-2:30 p.m. Eastern**.

Dr. Sarah Stafford, a Professor at the College of William and Mary working in Economics, Public Policy, and Law, will present the basic theories of compliance and deterrence and the findings of social science research on what techniques are most effective. She also will present some innovative approaches being used in programs across the U.S. to encourage facilities to increase voluntary compliance and to decrease inadvertent violations.

The Compliance Research Webinar Series, hosted by the National Enforcement Training Institute of the U.S. EPA Office of Enforcement and Compliance Assurance and designed for ECOS and U.S. EPA, helps program administrators understand how collaboration with academics can identify effective and measureable approaches to compliance.

For more information, please contact Sonia Altieri of ECOS. [Altieri]

ITRC on Long-term Contaminant Management Using Institutional Controls

On **November 14 at 1-3:15 p.m. Eastern**, the Interstate Technology and Regulatory Council (ITRC) will host a free online training on institutional controls (ICs), which are administrative or legal restrictions that provide protection from exposure to contaminants on a site.

After attending the training, participants will be able to describe best practices and evolving trends for IC management at individual sites and across state agency programs; improve IC reliability and prevent IC failures; improve existing, or develop new, IC management programs; identify the pros and cons about differing IC management approaches; and more.

Learn more and register here. [Bodi]

U.S. EPA on Drinking Water Issues

U.S. EPA's Office of Research and Development and the Office of Water host a monthly webinar series on small drinking water systems. Their schedule for the rest of the year is:

- **November 15** - National Stormwater Calculator for Managing Runoff
- **November 28** - Lead in Schools and Selecting Lead Free Fixtures
- **December 12** - Residual Chlorine and Calibration Check for Chlorine Instruments

More information on the small systems webinars, including recordings of past webinars and how to register, is available here. [Hanson]

U.S. EPA ORD on Cyanobacteria Monitoring

U.S. EPA's Office of Research and Development will hold its next monthly Tools and Resources webinar on **November 15 at 3-4 p.m. Eastern**.

The webinar will focus on monitoring cyanobacteria with satellites, highlighting how federal agencies (EPA, NASA, NOAA and USGS) are collaborating to use real-world satellite applications that support environmental management of U.S. lakes by quantifying cyanobacterial harmful algal blooms and related water quality parameters. This webinar will also address provisional satellite derived cyanobacteria data and three software tools available to state environmental and health agencies for review and testing as part of the Cyanobacteria Assessment Network (CyAN).

Register here. [Longsworth]

ITRC on PVI: Fundamentals of Screening, Investigation, and Management

On **November 16 at 1-3:15 p.m. Eastern**, the Interstate Technology and Regulatory Council (ITRC) will host a free online training on petroleum vapor intrusion (PVI), the process by which volatile petroleum hydrocarbons released as vapors from light nonaqueous phase liquids, petroleum-contaminated soils, or petroleum-contaminated groundwater migrate through the vadose zone and into overlying buildings.

After attending this training, participants should be able to determine when and how to use the ITRC PVI document at their sites; describe the important role of biodegradation impacts on the PVI pathway (in contrast to chlorinated solvent contaminated sites); value a PVI conceptual site model and list its key components; and more.

Learn more and register here. [Bodi]

NIH on Wildfire Risk Communication and Health Effects

On **November 17 at 1-2 p.m. Eastern**, the National Institutes of Health will host a webinar on the impacts of wildfires on the health of vulnerable individuals and on communities exposed periodically to such events.

The presentations will cover how environmental exposures associated with wildfires affect human health, as well as approaches being used to develop targeted risk communication about wildfires for a variety of audiences.

Register here.

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Jack Gerard, API
Sent: Thur 11/2/2017 1:28:37 PM
Subject: Regulatory Certainty on Ozone Can Protect U.S. Competitiveness

Click to view this email in a browser

November 2, 2017

Dear Samantha,

The combined emissions of six key air pollutants dropped 73 percent between 1970 and 2016, according to the Environmental Protection Agency's latest annual air quality report, and ground level ozone levels have decreased 17 percent since 2005. All this occurred during a time of significant economic growth, and these are achievements we all can and should be proud of since it is the result of the combined efforts of states, counties and industry to reduce air emissions.

Congress can ensure continued environmental and economic progress by implementing reforms to ozone regulations that eliminate duplicative regulatory requirements. In simple terms, EPA issued new ozone regulations in 2015 before its existing 2008 regulations –*the strictest in history* – had been fully implemented. That is leaving states in the costly position of attempting to comply with two competing sets of ozone regulations.

To understand how important reform is, take a look at the long and varied list of 303 organizations that wrote a letter explaining the economic impact of dueling standards that, in some cases, require states to achieve ozone levels approaching or below naturally occurring levels of ozone. The coalition includes local governments, chambers of commerce, businesses, and associations representing: manufacturers, construction workers, energy producers, dairy farmers, cattlemen, auto dealers, truckers, timber producers, restaurant and hospitality groups, poultry producers, convenience stores, engineers, grocers, retailers, and many others.

Here's what they had to say:

"If implemented, EPA's stringent ozone standards could limit business expansion in many areas of the United States and risk the ability of U.S. companies to create new jobs. The standards add red tape to companies seeking to grow even in areas that can attain those standards. … Increased costs associated with restrictive and expensive permit requirements could likely deter companies from siting new facilities in a nonattainment area, making the United States a less attractive place to do business and risking shipping jobs overseas."

The fact is, the strict 2008 ozone standards are working and will continue to reduce ozone concentrations. A House-passed bill would help cut the red tape and provide the regulatory certainty that states need to keep reducing ozone emissions without hurting job growth. The Ozone Standards Implementation Act of 2017, approved in the House earlier this year, recognizes ongoing state efforts to improve air quality, would reduce onerous requirements and facilitate the ability of businesses to expand operations and create jobs, while including other reforms that bring more regulatory certainty to federal air quality standards.

With Congress focused on tax reform and other budget issues, ozone regulatory reform fits right in as a policy priority with major economic implications for the entire nation. We urge the

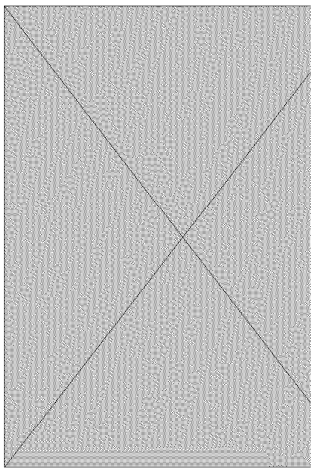
Senate to join the House in passing commonsense ozone regulatory reform.

Sincerely,

Jack N. Gerard
President & CEO
API

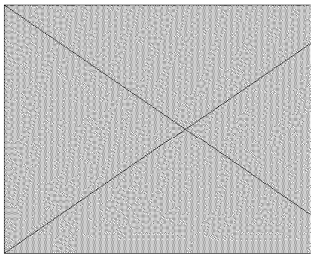
Offshore Development: Safety above All Else

Keeping our workforce safe is just one area of continuously improving safety that the natural gas and oil industry works hard on every day. One area where the industry brings a keen focus is the safety of offshore operations. Learn more about the regulations, safety practices, technology and environmental management systems that keep offshore production safe.



Follow our Blog to stay up-to-date

To stay up-to-date on the latest energy-related news, there is no better place to check than the Energy Tomorrow Blog.



About API:

API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 40 million Americans.

To learn more about API and the value of oil and natural gas, please visit API.org.

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---

Jack Gerard, API
1220 L Street, NW
Washington, DC 20005
US

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Ex. 6 - David Stevenson personal email
Sent: Tue 7/11/2017 5:48:12 PM
Subject: Ozone NAAQS question

Since implementation of 70 PPM standard for ozone has been delayed, shouldn't air quality reports revert to 75 PPM standard for daily AQI? Thanks.

David Stevenson

Director, Center for Energy Competitiveness

Caesar Rodney Institute

State Policy Network energy policy team?

Cell # Ex. 6 - Personal Privacy

Sent from Mail for Windows 10

To: Dravis, Samantha[dravis.samantha@epa.gov]
Cc: Hupp, Millan[hupp.millan@epa.gov]
From: Shea, Quin
Sent: Mon 3/27/2017 8:47:11 PM
Subject: Following Up on EEI Board Meeting
CasesList_032717_Final.docx

Samantha: Thanks again for efforts by you, Millan and others on the EPA team in arranging for Administrator Pruitt to address the EEI Board of Directors. The Administrator's remarks were extremely well received and provided ample food for thought going forward. In that vein, during the Q&A session the Administrator requested a list of current and pending milestones in cases impacting EEI's members. An initial list is attached. Importantly, it focuses on items that EEI has traditionally engaged and/or where industry unanimity has been established. Individual EEI member companies may supplement this list with additional priorities related to their local operations.

I hope you find this note responsive to the Administrator's request. I will follow up with you relative to this and other matters we discussed at the EEI meeting.

Quinlan J. Shea, III (Quin)

Vice President, Environment

Edison Electric Institute

701 Pennsylvania Avenue, NW

Washington, DC 20004

202-508-5027

qshea@eei.org

Currently Active EPA Cases

Air

Arkansas v. EPA – Regional Haze FIP, 8th Circuit. Nos. 16-4270 et al.

- Currently held in abeyance; reconsideration petition proceeding pending

Texas v. EPA – Regional Haze FIP, 5th Cir. No. 16-60118.

- Stay granted, remanded to EPA for reconsideration; stay remains in place, although status report on stay required from EPA in April

Utah v. EPA – Regional Haze FIP, 10th Cir. Nos. 16-9541, et al.

- Petitioners have filed opening briefs (March 10 and 17, 2017)

Wyoming v. EPA – Regional Haze FIP, 10th Cir. Nos. 14-9529, 14-9530, 14-9533 and 14-9534.

- Stay granted, briefing completed and oral argument not yet scheduled. Settlement of one of the cases, No. 14-9533, proposed and comment period closed; EPA deadline to take action on proposed settlement is April 3, 2017

Texas v. EPA – Regional Haze Rule, D.C. Cir. No. 17-1021.

- Petitions for review filed

West Virginia v. EPA – Clean Power Plan, D.C. Cir. Nos. 15-1363, et al.

- Oral argument completed, awaiting decision or further motions, motions to consolidate challenges to denial of reconsideration petitions pending

North Dakota v. EPA – New Source Standard, D.C. Cir. Nos. 15-1381, et al.

- Briefing completed, oral argument scheduled for April 17, 2017

Murray Energy v. EPA – Ozone NAAQS, D.C. Cir. No. 15-1385.

- Briefing completed, oral argument scheduled for April 20, 2017

Wisconsin v. EPA – CSAPR Update Rule, D.C. Cir. No. 16-1406.

- Petitions for review filed

Utility Air Regulatory Group v. EPA – CSAPR > BART Rule, D.C. Cir. No. 12-1342.

- Briefing completed, oral argument not yet scheduled

Murray Energy v. EPA & *ARIPPA v. EPA* – MATS Cost Considerations & Reconsideration Denial, D.C.

Circuit. Nos. 16-1127 & 15-1180 et al.

- Briefing completed, oral argument scheduled for May 18, 2017

Center for Biological Diversity v. EPA – NO_2 NAAQS Deadline Suit, 3:16-cv-03796-VC (N.D. Cal.).

- Settled, requires EPA to propose a rule by July 14, 2017 and finalize by April 16, 2018

Sierra Club v. EPA – Kentucky 2008 Transport Deadline Suit, 3:14-cv-03985-JD (N.D. Cal.).

- Motion for summary judgment hearing held March 23, 2017

Walter Coke, Inc. v. EPA – SSM SIP Call, D.C. Cir. No. 15-1166.

- Briefing completed, oral argument scheduled for May 8, 2017

Solid Waste

USWAG v. EPA – Coal Combustion Residuals, D.C. Cir. No. 15-1219.

- Briefing completed, oral argument not yet scheduled

American Petroleum Institute v. EPA – Definition of Solid Waste, D.C. Cir. Nos 09-1038, et al.

- Oral Argument completed, awaiting decision

Water

In re EPA-Corps WOTUS Rule – WOTUS, 6th Cir. Nos. 15-3799, et al.

- Being held in abeyance since the Supreme Court accepted cert on jurisdictional question for the October, 2017 term

SWEPCO v. EPA – ELGs, 5th Cir. Nos. 15-60821, et al.

- Briefing is ongoing, EPA recently received a 30 day extension on its response, oral argument anticipated fall 2017; Petitioners have sought administrative stay and reconsideration

Cooling Water Intake Structures Coalition v. EPA – Cooling Water Intake Structures, 2nd Cir. Nos. 14-4645, et al.

- Briefing completed, oral argument not yet scheduled

Miscellaneous

Title V Petitions

Enforcement cases and related penalties and settlements

Various NSR Cases

Other Cases Relevant to EPA, but where EPA is Not the Lead Agency:

Endangered Species

NRDC v. Sobeck – Blueback Herring listing decision, No. 1:15-cv-00198-RDM (D.D.C.).

CBD+DOW v. Ashe, Northern Long-Eared Bat, Nos. 1:15-cv-00477+910 (D.D.C).

EWAC v. U.S. Dep't of the Interior, Incidental Take of Eagles, No. 1:15-cv-1486 (D.D.C.).

Alabama v. National Marine Fisheries Service, Critical Habitat, 1:16-cv-00593 (S.D. Ala.)

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Verma, Puneet (puve)
Sent: Tue 3/21/2017 8:49:24 PM
Subject: CTGs: Follow Up from Chevron Meeting Today
2016 10 27 Release of Final CTG Notice FR.pdf
2016 10 27 Release of Final CTG Notice FR.pdf

Samantha,

I spoke with our executives after their meeting with the Administrator this morning. They are very appreciative that he took the time to meet with them. Many thanks to you as well for attending.

I understand the issue of CTGs was raised. A copy of the federal register notice and final CTGs is attached. When you get a chance, can you please give me a call on my cell Ex. 6 - Personal Privacy to further discuss this item?

Regards,

Puneet Verma

Chevron – Federal Government Affairs

600 13th Street, NW, Suite 600

Washington, DC 20005

Office: (202) 408-5807

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TABLE—PMNS RECEIVED FROM JUNE 1, 2016 TO JUNE 30, 2016—Continued

Case No.	Date received	Projected end date for EPA review	Manufacturer importer	Use(s)	Chemical identity
P–16–0447	6/24/2016	9/22/2016	CBI	(G) Additive for coatings	(G) Alkyl alkenoate, dialkyl alkanediyl, polymer with alkyl alkenoate, substituted carbomonocycle, alkyl alkenoate and heteromonocycle alkyl alkenoate, diazene bis alkyl heteromonocycle initiated.
P–16–0448	6/27/2016	9/25/2016	CBI	(G) Oil additive	(G) Metal salts branched alkyl substituted carbomonocycle with substituted alkyl carbomonocycle complexes.
P–16–0449	6/27/2016	9/25/2016	CBI	(S) Use per FFDCA: Cosmetics; (S) Use per TSCA: Fragrance uses; scented papers, detergents, candles etc.	(S) 2,7-decadienal, (2e,7z)-
P–16–0453	6/29/2016	9/27/2016	Miwon North America, Inc.	(S) Resin for Industrial Coating	(G) Polyester acrylate.
P–16–0454	6/30/2016	9/28/2016	CBI	(G) material for highly dispersive use in consumer products.	(G) Trisubstituted alkenol.
SN–03–0015	6/22/2016	9/19/2016	Degussa Corporation	(S) Anti-graffiti systems; surface treatment of fabrics and porous mineral surfaces.	(G) Fluoro/amino silane mixture.
SN–03–0016	6/22/2016	9/19/2016	Degussa Corporation	(S) Anti-soiling surface treatment of glass and ceramic surfaces.	(S) Silane, triethoxy(3,3,4,4,5,5,6,6,7,7,8,8,8-tridecafluorooctyl)-
SN–12–0005	6/22/2016	9/19/2016	CBI	(G) Additive, open, non-dispersive	(G) Multi-walled carbon nanotubes.
SN–15–0004	6/22/2016	9/19/2016	CBI	(S) Slurry dispersion to be blended with coating compound and applied to fabric.	(G) Brominated compounds.
SN–15–0009	6/22/2016	9/19/2016	CBI	(G) Polymer additive	(G) Fatty acid amide.
SN–16–0005	6/22/2016	9/19/2016	CBI	(G) Abrasion resistant applications	(G) Potassium titanate.
SN–16–0009	6/22/2016	9/19/2016	CBI	(G) Additive for household products.	(G) Trialkylol homopolymer.
SN–16–0011	6/22/2016	9/219/2016	CBI	(S) Component of infrared absorption material.	(G) Cesium tungstate.
SN–16–0012	6/22/2016	9/20/2016	CBI	(S) Additive for flotation products; (S) Chemical intermediate.	(G) Fatty acid amidoamine.

Authority: 15 U.S.C. 2601 *et seq.*

Dated: October 21, 2016.

Pamela Myrick,

Director, Information Management Division, Office of Pollution Prevention and Toxics.

[FR Doc. 2016–26021 Filed 10–26–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2015–0216; FRL–9954–57–OAR]

RIN 2060–ZA22

Release of Final Control Techniques Guidelines for the Oil and Natural Gas Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: The Environmental Protection Agency (EPA) is announcing the availability of a final document titled, ''Control Techniques Guidelines for the Oil and Natural Gas Industry'' (EPA 453/B–16–001). This Control Techniques Guidelines (CTG) document provides state, local, and tribal air agencies (air agencies) information to assist them in determining reasonably available control technology (RACT) for volatile organic compound (VOC) emissions from select oil and natural gas industry emission sources.

DATES: This CTG document is effective October 27, 2016.

ADDRESSES: The final ''Control Techniques Guidelines for the Oil and Natural Gas Industry'' document is available primarily via the Internet at *http://www.epa.gov/airquality/oilandgas/index.html* or *https://www.epa.gov/laws-regulations/significant-guidance-documents-air* or the public docket at *http://www.regulations.gov,* Docket ID No. EPA–HQ–OAR–2015–0216.

FOR FURTHER INFORMATION CONTACT: Ms. Charlene Spells, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143–05), Research Triangle Park, NC 27711; telephone number: (919) 541–5255; fax number: (919) 541–3470; email: *spells.charlene@epa.gov.*

SUPPLEMENTARY INFORMATION:

Information About the Document

Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIP) for nonattainment areas must include RACT, including RACT for existing sources of emissions. Section 182(b)(2)(A) of the CAA requires that for areas designated nonattainment for an ozone national ambient air quality standard (NAAQS) and classified as Moderate, states must revise their SIP to include provisions to implement RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to states with areas designated nonattainment for an ozone NAAQS classified as Serious, Severe, and Extreme.

The CAA also imposes the same requirement on states in Ozone Transport Regions (OTR). Specifically, CAA section 184(b) provides that states in the OTR must revise their SIP to implement RACT with respect to all sources of VOC in the state covered by a CTG document issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979). In subsequent notices, the EPA has addressed how states can meet the RACT requirements of the CAA. The EPA developed this CTG document to provide air agencies information to assist them in determining what types of

control could constitute RACT for VOC emissions from select oil and natural gas sources. In developing the final CTG document, the EPA evaluated the sources of VOC emissions from the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. Based on available information and data, the EPA is providing final recommendations for RACT for select oil and natural gas industry emission sources. The VOC RACT recommendations contained in this final CTG document were made based on a review of the 1983 CTG document on equipment leaks from natural gas processing plants, the Oil and Natural Gas New Source Performance Standards, existing state and local VOC emission reduction approaches, and information on costs, emissions, and available emission control technologies and in response to comments received on the draft CTG document released for review on September 18, 2015 (80 FR 56577). Also, the EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. We considered information included in these white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending a RACT level of control for emission sources. Air agencies can use the recommendations in the CTG document to inform their determinations as to what constitutes RACT for VOC for those oil and natural gas industry emission sources in their particular areas. The information contained in the CTG document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself. The RACT recommendations, and corresponding model rule language, contained in the CTG document do not impose any legally binding requirements on any entity. The CTG document provides only recommendations for air agencies to consider in determining RACT. Air agencies are free to implement other technically-soundapproaches that are consistent with the CAA and the EPA's regulations.

The recommendations contained in the CTG document are based on data and information currently available to the EPA. These general recommendations may not apply to a particular situation based on circumstances not considered in the CTG document. Regardless of whether an air agency chooses to implement the recommendations contained in this CTG document, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry emission sources, air agencies must submit their RACT provisions to the EPA for review and approval as part of the SIP submission process. The EPA will evaluate the submissions and determine, through notice and comment rulemaking in the SIP review process, whether the submissions meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this CTG document into its RACT provisions, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of the rules and the EPA's SIP review process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA provides that a CTG document issued after November 15, 1990, include the period for submitting SIP revisions incorporating provisions to require RACT for the category of VOC sources covered by the CTG document. The EPA is providing a 2-yearperiod, from the effective date included in this Notice, for the required SIP submittal.

The Tribal Authority Rule (63 FR 7254, February 12, 1998) (TAR) identifies CAA provisions for which it is appropriate to treat Indian tribes in the same manner as air agencies (TAS). Pursuant to the TAR, tribes may apply for TAS for purposes of CAA section 110 and Part D planning requirements in CAA section 182. As a result, tribes may, but are not required to, apply for TAS for the purpose of developing a tribal implementation plan (TIP) addressing RACT for sources located in an area designated nonattainment for an ozone NAAQS with a classification of Moderate, Serious, Severe or Extreme within the tribe's jurisdiction. If the EPA grants that status and approves the TIP, the tribe would implement RACT in the area within the geographic scope of the TAS designation and the approved TIP. If a tribe does not seek and obtain the authority from the EPA to establish a plan, the EPA will be responsible for establishing CAA section 110 and 182 plans for reservations and trust lands, and any other lands under tribal jurisdiction, if the EPA determines that such a plan is necessary or appropriate to protect air quality in such areas. See 40 CFR 49.4 and 49.11.

A summary of the comments received on the draft CTG document and responses can be found in the docket at *http://www.regulations.gov* (Docket ID No. EPA–HQ–OAR–2015–0216).

Dated: October 20, 2016.

Gina McCarthy,

Administrator.

[FR Doc. 2016–25923 Filed 10–26–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9954–55–Region 3]

Notice of Tentative Approval and Opportunity for Public Comment and Public Hearing for Public Water System Supervision Program Revision for Maryland

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of approval and solicitation of requests for public hearing.

SUMMARY: Notice is hereby given that the State of Maryland is revising its approved Public Water System Supervision Program. Maryland has adopted drinking water regulations for the Stage 2 Disinfectants and Disinfection By-ProductsRule (Stage2). The U.S. Environmental Protection Agency (EPA) has determined that Maryland's Stage 2 Rule meets all minimum federal requirements, and that it is no less stringent than the corresponding federal regulation. Therefore, EPA has tentatively decided to approve the State program revisions.

DATES: Comments or a public hearing must be submitted by November 28, 2016. This determination shall become final and effective on November 28, 2016 if no timely and appropriate request for a hearing is received, and the Regional Administrator does not elect to hold a hearing on his own motion, and if no comments are received which cause EPA to modify its tentative approval.

ADDRESSES: Comments or a request for a public hearing must be submitted to the U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, PA 19103–2029. All documents relating to this determination are available for inspection between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday, at the following offices:

• Drinking Water Branch, Water Protection Division, U.S. Environmental Protection Agency Region III, 1650 Arch Street, Philadelphia, PA 19103–2029.

To: Pruitt, Scott[Pruitt.Scott@epa.gov]
Cc: Jackson, Ryan[jackson.ryan@epa.gov]; Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]; Leslie.Couvillion@BakerBotts.com[Leslie.Couvillion@BakerBotts.com]; Dravis, Samantha[dravis.samantha@epa.gov]
From: megan.berge@bakerbotts.com
Sent: Fri 5/26/2017 5:28:32 PM
Subject: Western Farmers Electric Cooperative Petition for Reconsideration of Oklahoma State and Unit Budgets under CSAPR
Subject: EPA–HQ–OAR–2015–0500; Re-Submission of Petition for Reconsideration of the Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS

Dear Administrator Pruitt,

This email follows up on a petition by Western Farmers Electric Cooperative ("WFEC") for reconsideration of the final rule entitled "Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS," 81 Fed. Reg. 74,504 (Oct. 26, 2016). The petition was originally submitted on December 22, 2016, and re-submitted on April 19, 2017, in both electronic and hard-copy form. The petition requests re-allocation of allowances to WFEC's Anadarko Plant units and re-calculation of Oklahoma's state budget. Most critically, WFEC seeks for EPA to correct a technical error that drastically under-allocated allowances to its Anadarko Plant units. WFEC believes its request is discrete (i.e., unit- and state-specific) and could be accomplished within the existing CSAPR program framework.

WFEC is an electric power generation and transmission cooperative serving customers in Oklahoma and New Mexico. WFEC also is proud to serve Altus Air Force Base. Failure to obtain relief from the CSAPR Update Rule in a timely manner may increase costs for these customers. Given that the 2017 ozone season is now underway, WFEC must make decisions about purchasing allowances and taking other actions to comply with the rule. As it stands, WFEC is facing an allowance shortfall for the 2017 ozone season.

Granting WFEC's petition would be consistent with Executive Order 13771, "Reducing Regulation and Controlling Regulatory Costs." Any resulting rulemakings are unlikely to qualify as "significant" regulatory actions subject to the order because they would be minor, technical actions affecting only a subset of regulated units or states. Further, any such rulemakings are unlikely to result in new incremental costs; to the extent they have total costs less than zero, they could qualify as "offsetting" de-regulatory actions that help EPA comply with the order.

WFEC appreciates any clarity you or your team can provide on EPA's intention to act on the petition. Thank you for your consideration.

Respectfully,

Megan

Megan Heuberger Berge

Partner
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BAKER BOTTS

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To: Pruitt, Scott[Pruitt.Scott@epa.gov]
Cc: Jackson, Ryan[jackson.ryan@epa.gov]; Dravis, Samantha[dravis.samantha@epa.gov]; Leslie.Couvillion@BakerBotts.com[Leslie.Couvillion@BakerBotts.com]
From: megan.berge@bakerbotts.com
Sent: Wed 4/19/2017 7:02:56 PM
Subject: Subject: EPA–HQ–OAR–2015–0500; Re-Submission of Petition for Reconsideration of the Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS
Western Farmers CSAPR Update Petition for Reconsideration.pdf
APPENDIX A-2 (WFEC) - EIA Data Substitution Calculations - 2016-1221-152....pdf
APPENDIX B-2 (WFEC) - Unit-Level Allocations with EIA Substitution (Scal....pdf
APPENDIX A-1 (WFEC) - Unit-Level Allocations with EIA Substitution (Fina....pdf
APPENDIX B-1 (WFEC) - Revised Appendix E State Budgets (Scaling Fix) - 2....pdf
APPENDIX C-1 (WFEC) - AQAT (Scaling Fix 7-State) - 2016-1221-1520.pdf
APPENDIX C-2 (WFEC) - AQAT (Scaling Fix OK Only) - 2016-1221-1520.pdf

Dear Administrator Pruitt,

Attached please find a petition by Western Farmers Electric Cooperative ("WFEC") for reconsideration of the final rule entitled "*Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*," Docket No. EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74,504 (Oct. 26, 2016). The attached petition and appendices were submitted to the prior administration on December 22, 2016, within the time period specified in the Clean Air Act.

Given that the 2017 ozone season is set to begin in May, WFEC must begin making decisions about purchasing allowances and taking other actions to comply with the regulation. WFEC's requested relief in its petition includes re-allocation of allowances to its Anadarko Plant units and re-calculation of Oklahoma's state budget. WFEC would appreciate any clarity you or your team can provide on EPA's intention to act on the petition.

A hard copy of the petition, along with a CD-Rom containing both PDF and Excel versions of the appendices, also is being sent to EPA via first-class USPS mail.

Respectfully,

Megan

Megan Heuberger Berge
Partner
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BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

In re:	)	EPA Docket No.
	)	
Cross-State Air Pollution Rule Update	)	EPA–HQ–OAR–2015–0500
for the 2008 Ozone NAAQS	)	
	)	

Western Farmers Electric Cooperative's Petition for Reconsideration of the *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*

Western Farmers Electric Cooperative ("Western Farmers") respectfully petitions the U.S. Environmental Protection Agency ("EPA" or "Agency") for reconsideration of the final rule entitled "*Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*," Docket No. EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74,504 (Oct. 26, 2016) ("CSAPR Update Rule" or "Final Rule").[1] Specifically, Western Farmers requests that EPA recalculate (1) unit-level allocations of seasonal nitrous oxide ("NOx") allowances for 2017 and beyond for Western Farmers' Anadarko Plant, using data-substitution called for by the Final Rule; and (2) Oklahoma's NOx seasonal emission budget for 2017 and beyond, using the proposed limited adjustment to EPA's budget calculation methodology to account for arbitrary modeling results.

Western Farmers is a not-for-profit company, and its primary mission is to provide affordable and reliable power to its consumers. Western Farmers is a generation and transmission cooperative that is owned by, and serves, 21 member distribution cooperatives in Oklahoma and New Mexico. Western Farmers also is proud to serve Altus Air Force Base. Western Farmers owns and maintains approximately 3,700 miles of transmission that is operated and administered by the Southwest Power Pool, and its diverse generating mix includes a single 450 megawatt ("MW") coal-fired generation unit at the Hugo plant and 14 natural gas-fired steam cycle, simple cycle, and combined cycle generating units at the Anadarko and Mooreland plants in Oklahoma.[2] Additionally, Western Farmers has been a leader in Oklahoma and the west in developing low- and zero-carbon emitting generation, with almost 600 MW of wind

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[1] Along with an electronic submission of this petition, Western Farmers is supplying EPA with a CD-Rom containing the six Appendices (Appendices A-1 to C-2). The Appendices are Excel datasheets and workbooks demonstrating the calculations and modeling described in this petition. The CD-Rom contains both a "locked" (*i.e.*, password-protected, read-only) version and an "unlocked" courtesy working copy of each file. Appendices B-1 and C-1-2 are modifications of EPA's own tools (Appendix E and AQAT, respectively) and use EPA's own cell formulas. Appendices A-1-2 and B-2 are Western Farmers' original files with cell formulas removed, but with all necessary data and explanation of the methodology underlying the calculations.

[2] As well as the 42 MW Wartsila plant in Lovington, New Mexico.

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energy resources currently, and another 30 MW wind facility planned for 2017. Also, Western Farmers added solar to its portfolio mix in 2016 (to come online in early 2017), including 25 MW of solar energy under contract and just over 20 MW of owned solar energy resources.[3]

BACKGROUND

CSAPR addresses the "good neighbor" provision of the Clean Air Act, which prohibits sources within each state "from emitting any air pollutant in an amount which will . . . contribute significantly" to any other state's nonattainment, or interference with maintenance of, any NAAQS. 42 U.S.C. § 7410(a)(2)(D)(i)(I). EPA defines "significant contribution" by reference to (1) a state's "linkage" to downwind receptors (*i.e.*, emissions of approximately 1 percent of compliant ambient levels);[4] and (2) the ability of the state to achieve emission reductions at the relevant cost threshold.[5] CSAPR achieves emissions reductions through annual and ozone season emissions trading programs.

EPA finalized CSAPR in 2011 to address three NAAQS, including the 1997 ozone NAAQS. 76 Fed. Reg. 48,208 (Aug. 8, 2011) ("Original CSAPR Rule" or "CSAPR"). In December 2011, EPA finalized a supplemental CSAPR rule that added several states, including Oklahoma, to the ozone season NOx program. 76 Fed. Reg. 80,760 (Dec. 27, 2011) ("Supplemental CSAPR Rule"). Various groups challenged CSAPR, resulting in a stay of the rule. *See EME Homer City Generation, L.P. v. EPA*, No. 11-1302 (D.C. Cir. Dec. 30, 2011). CSAPR and Supplemental CSAPR Rule requirements and deadlines were effectively tolled pending resolution of the litigation. *See* 79 Fed. Reg. 71,663 (Dec. 3, 2014). In April 2014, the U.S. Supreme Court generally upheld the rule, *see EPA v. EME Homer City Generation LP*, 134 S. Ct. 1584 (2014), and the stay was lifted in October 2014. *See EME Homer City*, No. 11-1302 (Oct. 23, 2014). Phase 1 of the CSAPR ozone season program began in May 2015.

EPA published the Final CSAPR Update Rule in October 2016 to address good neighbor provisions with respect to the 2008 ozone NAAQS. The Agency had published a proposed rule

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[3] WFEC purchases or produces energy from various wind sources, and, in the near future, solar resources. However, WFEC has not historically, nor may not in the future, retain or retire all of the renewable energy certificates associated with the energy production from these facilities.

[4] EPA used an ozone air quality assessment tool ("AQAT") to determine which states contribute to ozone concentrations at maintenance and non-attainment downwind receptors, and to estimate the impact of upwind states' NOx emissions reductions on downwind ozone pollution concentrations. The AQAT was developed specifically for the CSAPR Update Rule. EPA, *Regulatory Impact Analysis of the Cross-State Air Pollution Rule (CSAPR) Update for the 2008 National Ambient Air Quality Standards for Ground-Level Ozone* (Sept. 2016) at 3-10, available at https://www3.epa.gov/ttn/ecas/docs/ria/transport_ria_final-csapr-update_2016-09.pdf ("Regulatory Impact Analysis").

[5] EPA used the Integrated Planning Model v.5.15 ("IPM") to predict how many emissions reductions are available at the relevant cost thresholds. IPM is a dynamic, linear programming model used to project power sector behavior under current and future conditions. IPM's primary objective is to provide estimates of least-cost capacity expansions, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. *See* https://www.icf.com/solutions-and-apps/ipm.

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about 10 months earlier. *See* 80 Fed. Reg. 75,706 (Dec. 3, 2015) ("Proposed CSAPR Update Rule" or "Proposed Rule"). In the Final Rule, EPA found that 22 eastern states, including Oklahoma, had failed to submit a state implementation plan to meet their good neighbor obligations. For these 22 states, EPA issued federal implementation plans that generally update existing CSAPR NOx ozone season emission budgets, and that implement these budgets through modifications to the existing CSAPR NOx ozone season allowance trading program. The Final Rule addresses only emission reductions from electric generating units ("EGUs"). Implementation will start in the 2017 ozone season (May - September 2017).

EPA made several significant changes between the Proposed and Final CSAPR Update Rules. Most notably for Western Farmers and other Oklahoma generators:

(1) **In calculating allocations for Oklahoma units in the Final Rule, EPA did not use data-substitution**. Both the Proposed and Final Rules call for EPA to use up to *five* years of historic heat input data and up to *eight* years of historic NOx emissions data. To accomplish this, both rules also call for EPA to use a data-substitution method (so that if data is not available from EPA's preferred data source for a given year, EPA can pull equivalent data from an alternative source).[6] EPA followed this method in the Proposed Rule.[7] But in the Final Rule, EPA switched to using a *single year of historic baseline data without any data-substitution* for the Anadarko Plant and other Oklahoma units. EPA's error in the Final Rule led to a drastic (over 80 percent) reduction in the Anadarko Plant units' allocations from the Proposed Rule to the Final Rule.[8]

(2) **In calculating Oklahoma's budget in the Final Rule, EPA used a revised formula with new inputs**. Specifically, EPA introduced new variables, including (1) a NOx emission rate "delta" (equal to the difference between an IPM 2017 Final Base Case and IPM 2017 Final $1,400/ton Cost Case emission rate); and (2) an "adjusted" historic emission rate, based on a newly-developed dataset.[9] For seven states, including Oklahoma, the IPM 2017 Base Case

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[6] The two data sources EPA says it will look to are: (1) EPA's Clean Air Markets Division ("CAMD"), for years for which it is available; and (2) U.S. Energy Information Administration ("EIA"), for years for which CAMD data is unavailable.

[7] With some caveats: EPA did not include 2014 EIA data because it was unavailable at the time the Proposed Rule was published. Thus, for units without 2014 CAMD data, EPA did not "backfill" or substitute any EIA data. Additionally, EPA did not include data for years for which a unit was not yet operating (*e.g.*, if a unit that began operating in 2012, EPA used available 2012-2014 heat input and NOx emissions data). *See* EPA, Proposed Rule, *Unit Level Allocations and Underlying Data for the CSAPR for the 2008 Ozone NAAQS* ("Proposed Allocation Spreadsheet TSD"). Excel file available at https://www.epa.gov/airmarkets/proposed-cross-state-air-pollution-update-rule. Further, as discussed below, it appears that EPA inappropriately relied on annual, not monthly, EIA data and made arbitrary downward adjustments to reported EIA data for cogeneration and combined cycle units. EPA should use monthly, reported (*i.e.*, unadjusted) EIA data in the revised Final Rule allocations.

[8] *See* Part I below.

[9] Both the Proposed and Final Rules call for EPA to set state budgets as the minimum of either (1) historic emissions or (2) IPM-predicted 2017 emissions. EPA's changes pertain to the formula for calculating IPM-predicted 2017

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emission rate is significantly higher than the state's historic actual or adjusted 2015 emission rates—an unrealistic and arbitrary outcome (the "***Perverse IPM Result***"). The Perverse IPM Result creates an arbitrarily high "delta" value, causing EPA to overestimate the amount of available emission reductions in the state. Carried through the rest of the formula, this error results in an unrealistically low state budget. Oklahoma's budget is approximately 28 percent lower in the Final Rule than it was in the Proposed Rule—*the most drastic reduction for any state*.[10]

REQUEST FOR RECONSIDERATION

The Clean Air Act requires that EPA grant reconsideration of a regulation if a petitioner "can demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment . . . and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(B). In such a situation, reconsideration is mandatory: EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added).

The notice-and-comment requirements of the Clean Air Act and the Administrative Procedure Act further require that EPA's "proposed rule and its final rule . . . differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). A "final rule is a 'logical outgrowth' of a proposed rule *only* if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Id.* at 998.

EPA must grant reconsideration of the CSAPR Update Rule because:

(1) **In calculating allocations for Oklahoma units**, EPA made a clear technical error by failing to use EIA data-substitution for the Anadarko Plant and other units. As described further below, the grounds for this objection arose after the public comment period. EPA did not make a similar error in the Proposed Rule, nor did EPA give notice of, or seek comment on, the option of *not* using data-substitution—so that some units would receive allocations based on a *single* baseline year—in the Final Rule. This objection is of central relevance to the outcome of the Final Rule. EPA's error threatens Western Farmers' ability to comply with the Final Rule, especially given the extremely short compliance timeframe for the 2017 ozone season. It has also created an unfair and unrepresentative distribution of allowances within Oklahoma, making it harder for the state to comply efficiently with the rule. Compliance feasibility and efficiency are central to the outcome of the CSAPR Update Rule.

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emissions. EPA used a historic emissions baseline period of 2014 in the Proposed Rule and 2015 in the Final Rule. *See* Part II below.

[10] The primary driver of this drop in Oklahoma's budget appears to be the new IPM-predicted 2017 emissions formula, not the switch from a 2014 to 2015 historic baseline year. *See* Part II below.

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(2) **In calculating Oklahoma's budget**, EPA used a new formula with inaccurate and perverse data inputs that overestimated the available emissions reductions in the state. As described further below, the grounds for this objection arose after the public comment period. EPA's broad request in the Proposed Rule for comment on "all aspects" of quantifying state budgets did not give Western Farmers reasonable notice of the highly complex changes EPA would adopt in the Final Rule—changes that would negatively impact Oklahoma more than any other state. This objection is of central relevance to the outcome of the Final Rule. Oklahoma's current Final Rule budget is unrealistically and arbitrarily low. This threatens the ability of *all* covered Oklahoma units to comply with the rule.

I. UNIT-LEVEL ALLOWANCE ALLOCATIONS

A. EPA Should Follow its Own Methodology and Use EIA Data-Substitution

EPA's unit-level allowance allocation calculations in the Final Rule are arbitrary and capricious as applied to Western Farmers' Anadarko Plant units. EPA's failure to perform EIA data-substitution—and use of a single historic baseline year for some units—goes against the Final Rule's own prescribed methodology. It also puts units on unequal footing: some units received allocations based on one year of operation, while other units received allocations based on multiple years of operation. This effectively penalizes units, like the Anadarko Plant units, that had no obligation to report data to CAMD in prior years.

EPA must recalculate Western Farmers' allocations for the Anadarko Plant units to avoid this unfair and arbitrary outcome. Specifically, EPA must use (1) five years of reported heat input data (2011-2015) and eight years of reported NOx emissions data (2008-2015); and (2) EIA data-substitution, where CAMD data is unavailable. Therefore, the allocations should be based on 2011-2014 EIA and 2015 CAMD heat input data and 2008-2014 EIA and 2015 CAMD NOx emissions data. EPA should use monthly (not annual), reported (not adjusted) data. *See* Appendix A-1 for detailed proposed calculations.[11]

1. What EPA Said it Would Do

Western Farmers' request to EPA is straightforward: simply do what you said you would do (but did not actually do). The Final Rule calls for using a five-year (2011-2015) historic baseline period for heat input data, and an eight-year (2008-2015) historic baseline period for NOx emissions data. *See* Allocation TSD at 6-7.[12]

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[11] Where reported unit-level heat input EIA data is unavailable, EPA should make the best estimate based on reported plant-level EIA heat input data and reported unit-level heat input data (*e.g.*, from CAMD). Appendix A-2 includes a detailed proposed estimation technique.

[12] EPA's allocation methodology has two main phases: (1) **Heat Input Data Phase:** EPA "uses the average of the three highest years of heat input data out of a consecutive five-year period [2011-2015] to establish the heat input baseline for each unit." 81 Fed. Reg. at 74,564. EPA then calculates initial heat input-based allowance allocations based on each unit's percentage share of the state's total ozone season heat input; and (2) **NOx Emissions Data Phase:** EPA then "constrains the unit-level allocations so as not to exceed the maximum historical baseline emissions, calculated as the highest year of emissions out of a consecutive eight-year period [2008-2015]." *Id.*

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EPA's rationale for using multiple historic baseline years is sound: it helps ensure that outlier data from a single unrepresentative year (*e.g.*, where heat input or NOx emissions levels were significantly lower than usual) does not skew the calculations.[13] As EPA recognizes, the power sector is susceptible to a range of variables affecting fuel use and emissions, including equipment failures, changing market forces, and weather patterns. *See* 81 Fed. Reg. at 74,566. One year of historic data cannot capture the inherent variability in a unit's operations from year to year, or ozone season to ozone season.

EPA says it will to look to two possible sources to obtain this historic data:

(1) First, EPA's CAMD database, which contains data from units already reporting under CSAPR or other trading programs, such as the Clean Air Interstate Rule or the Acid Rain Program; and

(2) Second, EIA forms, "where EPA data are unavailable." *Id.* at 6-7.

Under this approach, the only baseline years for which a unit should have a "missing" value are baseline years "for which a unit has ***no*** data on heat input (*e.g.*, for a baseline year before the year when a unit started operating)." *Id.* at 7 (emphasis added). In other words, if CAMD data is available for a unit for a particular year within the relevant historic baseline period, EPA should use that CAMD data. If CAMD data is unavailable but EIA is available, EPA should use the EIA data.[14] *If and only if neither* CAMD *nor* EIA data is available (*e.g.*, because the unit was not yet operating), EPA should use no data—*i.e.*, "zero" values.

Indeed, for many units EPA *must* look to a historic data source other than CAMD to populate the multi-year baseline periods called for in the Final Rule. Prior to Phase I of the CSAPR program in 2015, many units, including the Anadarko Plant units, had no obligation to report data to CAMD under any EPA program. The Anadarko Plant units have only a single year of reported CAMD data (2015), but multiple years of EIA data (back to before 2008, the earliest relevant baseline year under the Final Rule). Under such circumstances, EPA's methodology calls for the Agency to use a combination of 2015 CAMD data and 2008-2014 EIA data to establish unit allocations.

Overall, this methodology "bases a unit's allocation on the unit's historical heat input but limits any unit's allocation to its historical maximum emissions." EPA, *Allowance Allocation Final Rule TSD* at 6 (Aug. 2016) ("Allocation TSD"). Available at https://www3.epa.gov/airmarkets/CSAPRU/CSAPR%20Allowance%20Allocations%20Final%20Rule%20TSD.PDF.

[13] *See* Allocation TSD at 7. EPA chose a multi-year heat input baseline because "[s]electing the three highest, non-zero ozone season heat input values within the five-year baseline reduces the likelihood that any particular single year's operations (which might be negatively affected by outages or other unusual events) determine a unit's allocation." *Id.* EPA chose a multi-year NOx emissions baseline "in order to capture the unit-level emissions before and after the promulgation of the original CSAPR." *Id.*

[14] For certain years and facilities, EIA heat input data is reported only on a plant-level, not unit-level, basis. As noted above, EPA should make its best estimate of unit-level heat input data. *See* Appendices A-1 and A-2.

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EPA also states it will look to publicly available, *reported* EIA data.[15] EPA does not state, in either the Final Rule or the Allocation TSD, that the Agency will adjust EIA data from what is reported directly on the EIA forms.[16] EPA therefore should use *monthly (not annual), reported (not downward-adjusted for combined cycle and cogeneration units)* EIA data whenever EIA data is called for in allocation calculations. Monthly data is better than annual data with a crude 5/12 multiplier because monthly data more accurately reflects actual ozone season operations.[17] Reported heat input data is better than downward-adjusted heat input data for cogeneration and combined cycle units because reported data more accurately reflects these units' actual fuel use, as well as their highly efficient processes.[18] Using monthly, reported EIA data also is consistent with EPA's treatment of CAMD data, which EPA did not adjust when incorporating it into the Final Rule's current allocation calculations. Treating EIA and CAMD data differently would be arbitrary and capricious.

2. What EPA Actually Did

In the Final Rule, EPA inexplicably relied on *only* CAMD data, without backfilling EIA data, in its Oklahoma unit allocations. *See* EPA, Final Rule, *Unit-Level Allocations and Underlying Data for the CSAPR Update for the 2008 Ozone NAAQS* ("Final Allocation Spreadsheet TSD").[19] Several units, including the Anadarko Plant units, had only a single year (2015) of reported CAMD data, because these units were not required to report data to CAMD

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[15] Specifically, EPA "used historical heat input and emissions data [EIA] forms, 860, 906, 920, and 923. These data are publicly available at http://www.eia.doe.gov/cneaf/electricity/page/data.html." Allocation TSD at 6.

[16] In the Proposed Rule, EPA appears to have altered Western Farmers' reported EIA data in two ways: (1) instead of looking at *monthly* data for ozone season months, EPA took *annual* data and multiplied it by 5/12 to estimate ozone season operations (because the ozone season comprises 5 months out of the year); and (2) instead of using total reported heat input values, EPA applied a downward "proportional nameplate capacity adjustment" to cogeneration and combined cycle units, which have both a gas turbine and a steam turbine that produce electricity (basically, EPA multiplied the gas turbine's share of the plant's total nameplate capacity by the plant's total heat input). Both of these data manipulations are inappropriate. EPA historically has used reported, monthly EIA data—as it should again here.

[17] The 5/12 ozone season multiplier incorrectly assumes that units operate more or less the same during all 12 months of the year. In fact, the Anadarko Plant units operate *significantly more* during the ozone season because they are highly-efficient natural gas-fired units that are called on during peak periods of electricity demand, which often coincide with ozone season summer months. Further, monthly EIA data for May-September for 2008-2014 is available for these units; there is no reason not to use it.

[18] The "proportional nameplate capacity adjustment" for cogeneration and combined cycle units misunderstands how these units operate and punishes these units for being efficient. *All* fuel consumed in combined cycle units is used in electricity generation: fuel is combusted in the gas turbine to either produce power or produce steam, which then produces power (in the steam turbine). Therefore, the adjustment punishes units for employing a more efficient process that reuses gas turbine exhaust to produce steam and more electricity, rather than just venting it off.

[19] Excel file available at https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update.

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under any EPA program prior to 2015.[20] However, the Anadarko Plant and other Oklahoma units *do* have multiple prior years of available EIA data. EPA could easily backfill this EIA data into its allocation calculation spreadsheet. EPA does not explain why the Agency did not perform this data-substitution in the Final Rule's allocation calculations.

B. Corrected Calculations Show the Anadarko Plant Units Should Receive ***Over 120*** Additional Allowances

EPA's approach arbitrarily reduced the allowances allocated to the Anadarko Plant units. As shown in the figures and tables below, the Final Rule's allocations for the Anadarko Plant units are *more than 75 percent below what they should be* under EPA's allocation method that incorporates EIA data-substitution,[21] and *over 80 percent below what they were under the Proposed Rule*.[22] To correct the allocations for the Anadarko Plant units, Western Farmers used monthly, unadjusted EIA heat input data from EIA forms 923, 860, 906, and 920.[23] *See* Appendix A-2.[24] Western Farmers also pulled publicly available, reported EIA heat input data and performed data-substitution for *all* Oklahoma units. However, Figures 1-4 below show the results for only the Anadarko Plant units.

Figure 1 shows the historic heat input data EPA relied on in performing the initial heat input-based allocation calculations (Steps 1-6) for the Anadarko Plant units in the current Final Rule, while **Figure 2** shows the historic heat input data EPA should have relied on:

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[20] Western Farmers' analysis indicates that other Oklahoma units with only a single year of CAMD data include AES Shady Point, Mustang, Oklahoma Cogeneration LLC, and Weleetka units.

[21] Under the Final Rule, the Anadarko Plant units have allocations of 9 tons, 14 tons, and 17 tons, respectively (40 tons combined). Using the corrected method, the Anadarko Plant units would receive allocations of 52 tons, 53 tons, and 56 tons, respectively (161 tons combined). *See* Figures 1-4 and Table 1 below.

[22] Under the Proposed Rule, the Anadarko Plant units would have had allocations of 77 tons each (231 tons combined).

[23] For facilities reporting EIA heat input data at a plant-level, not unit-level, an estimation technique was used to arrive at unit-level heat input data. First, the total reported plant-level heat input (EIA) was reduced by the total reported unit-level heat input for all units for which reported data was available (from EIA or CAMD). Then, the remaining heat input was distributed evenly among the unreported units. *See* Appendix A-2.

[24] For the NOx emission data shown in Figure 4, Western Farmers relied on the NOx emissions values used in the Proposed Rule, due to the company's limited resources and the time it would take to calculate updated NOx emissions values based on monthly, unadjusted EIA data (instead of the annual, adjusted EIA data used in the Proposed Rule). Because *only the maximum* historic NOx emissions affect the unit allocations, re-calculating the NOx emissions values is not expected to impact the final allocations.

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Figure 1. Historic Heat Input Data (Current Final Rule Allocations).

				Step 1					Steps 2 & 3	Step 4	Step 5	Step 6	
Plant Name	ORIS ID	Boiler ID	CAMD Unit ID	2011 Ozone Season Heat Input (mmBtu)	2012 Ozone Season Heat Input (mmBtu)	2013 Ozone Season Heat Input (mmBtu)	2014 Ozone Season Heat Input (mmBtu)	2015 Ozone Season Heat Input (mmBtu)	Unit Level Average of 3 Highest Non-Zero Ozone Season Heat Inputs from 2011 to 2015 (mmBtu)	State Level Summation of Unit Level Three Year Average Ozone Season Heat Input (mmBtu)	Unit's Percentage Share of State's Ozone Season Heat Input	Ozone Season NO_X 2017 State Budget for Existing Units (tons)	Initial Heat Input Based 2017 Ozone Season NO_X Allocation (tons)
Calculation									Average of three highest non-zero values in columns F - J	Sum column K values to get State level totals	Column K divided by column L		Column M x column N
Anadarko Plant	3006	4	90966					736,757	736,757	339,851,789	0.002168	11,408	25
Anadarko Plant	3006	5	90967					1,118,066	1,118,066	339,851,789	0.003290	11,408	38
Anadarko Plant	3006	6	90968					1,335,829	1,335,829	339,851,789	0.003931	11,408	45

Figure 2. Historic Heat Input Data (Corrected Final Rule Allocations).

				Step 1					Steps 2 & 3	Step 4	Step 5	Step 6	
Plant Name	ORIS ID	Boiler ID	CAMD Unit ID	2011 Ozone Season Heat Input (mmBtu)	2012 Ozone Season Heat Input (mmBtu)	2013 Ozone Season Heat Input (mmBtu)	2014 Ozone Season Heat Input (mmBtu)	2015 Ozone Season Heat Input (mmBtu)	Unit Level Average of 3 Highest Non-Zero Ozone Season Heat Inputs from 2011 to 2015 (mmBtu)	State Level Summation of Unit Level Three Year Average Ozone Season Heat Input (mmBtu)	Unit's Percentage Share of State's Ozone Season Heat Input	Ozone Season NO_X 2017 State Budget for Existing Units (tons)	Initial Heat Input Based 2017 Ozone Season NO_X Allocation (tons)
Calculation									Average of three highest non-zero values in columns F - J	Sum column K values to get State level totals	Column K divided by column L		Column M x column N
Anadarko Plant	3006	4	90966	1,310,612	1,426,485	1,031,944	725,860	736,757	1,256,347	341,127,969	0.003683	11,408	42
Anadarko Plant	3006	5	90967	1,310,612	1,426,485	1,031,944	605,014	1,118,066	1,285,054	341,127,969	0.003767	11,408	43
Anadarko Plant	3006	6	90968	1,310,612	1,426,485	1,031,944	911,748	1,335,829	1,357,642	341,127,969	0.003980	11,408	45

In the current Final Rule, heat input data for 2011-2014 is effectively treated as "zero." This is historically inaccurate and distorts the calculations. Under this method, the Step 6 initial heat input-based allowance allocations for the Anadarko Plant units are 25 tons, 38 tons, and 45 tons, respectively. Under the corrected method where available EIA heat input data from the years 2011-2014 is backfilled, the Step 6 initial heat input-based allowance allocations are 42 tons, 43 tons, and 45 tons, respectively.

Figure 3 shows the historic NOx emissions data EPA relied on in performing the final allowance allocation calculations (Steps 7-10) for the Anadarko Plant units in the current Final Rule, while **Figure 4** shows the historic NOx emissions data EPA *should have* relied on:

Figure 3. Historic NOx Emissions Data (Current Final Rule).

				Step 7								Step 8	Steps 9 & 10
Plant Name	ORIS ID	Boiler ID	CAMD Unit ID	2008 Ozone Season NO_X Emissions (tons)	2009 Ozone Season NO_X Emissions (tons)	2010 Ozone Season NO_X Emissions (tons)	2011 Ozone Season NO_X Emissions (tons)	2012 Ozone Season NO_X Emissions (tons)	2013 Ozone Season NO_X Emissions (tons)	2014 Ozone Season NO_X Emissions (tons)	2015 Ozone Season NO_X Emissions (tons)	Ozone Season NO_X Maximum Historic Baseline (tons)	Final Transport Rule Unit Level NO_X Ozone Season Allocation 2017 (tons)
Calculation												Highest value of columns P - W	(Lesser of columns X and O + reapportionment if O < X
Anadarko Plant	3006	4	90966								9	9	9
Anadarko Plant	3006	5	90967								14	14	14
Anadarko Plant	3006	6	90968								17	17	17

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Figure 4. Historic NOx Emissions Data (Corrected Final Rule).

				Step 7								Step 8	Steps 9 & 10
Plant Name	ORIS ID	Boiler ID	CAMD Unit ID	2008 Ozone Season NO_X Emissions (tons)	2009 Ozone Season NO_X Emissions (tons)	2010 Ozone Season NO_X Emissions (tons)	2011 Ozone Season NO_X Emissions (tons)	2012 Ozone Season NO_X Emissions (tons)	2013 Ozone Season NO_X Emissions (tons)	2014 Ozone Season NO_X Emissions (tons)	2015 Ozone Season NO_X Emissions (tons)	Ozone Season NO_X Maximum Historic Baseline (tons)	Final Transport Rule Unit Level NO_X Ozone Season Allocation 2017 (tons)
Calculation												Highest value of columns P - W	(Lesser of columns X and O + reapportionment if O < X
Anadarko Plant	3006	4	90966	112	102	119	83	99	30		9	110	52
Anadarko Plant	3006	5	90967	112	102	119	83	99	30		14	110	53
Anadarko Plant	3006	6	90968	112	102	119	83	99	30		17	110	56

In the current Final Rule, EPA's approach—*which effectively assumes the units had "zero" emissions for 2008-2014*—sets Step 8 maximum emissions "upper bound" limits of 9 tons, 14 tons, and 17 tons, respectively. These values serve as "caps" on final allocations, and effectively override and replace the initial Step 6 allocations from Figure 1. Thus, final allocations under Steps 9 & 10 are 9 tons, 14 tons, and 17 tons, respectively.

Under the corrected method where available EIA NOx emissions data for 2008-2014 is backfilled,[25] the Step 8 maximum emissions "upper bound" limits are significantly higher, at 119 tons for all three Anadarko Plant units. This is a much more generous cap, allowing for final allocations under Steps 9 & 10 that are based on taking the initial Step 6 allocations from Figure 2 and adding a reapportionment adjustment. This amounts to final allocations of 52 tons, 53 tons, and 56 tons, respectively (161 combined)—or an additional 43 tons, 39 tons, and 39 tons, respectively (an additional 121 tons combined). Table 1 summarizes the impact of the corrected calculations on the Anadarko Plant units:

Table 1. Impact of Performing EIA Data-Substitution on Anadarko Plant Unit Allocations.

Plant Name	ORIS ID	Boiler ID Proposed/Final	Ozone Season NO_X Maximum Historic Baseline (tons)		Final Transport Rule Unit Level NO_X Ozone Season Allocation 2017 (tons)			Change (Final CSAPR to Scaling Fix) (tons)
			Proposed CSAPR	Final CSAPR	Proposed CSAPR	Final CSAPR	Allocation w/ EIA Data	
Anadarko Plant	3006	4	145	9	77	9	52	43
Anadarko Plant	3006	5	145	14	77	14	53	39
Anadarko Plant	3006	6	145	17	77	17	56	39

In sum, under the corrected method, the Anadarko Plant units should receive a combined total of approximately 161 additional allowances (39-43 additional allowances each). *See* Appendix A-1 for a complete version of Table 1 showing the impact of EIA data-substitution on all Oklahoma unit allocations.

[25] NOx emissions data for 2014 was not readily available to Western Farmers. Excluding the 2014 data is not expected to impact these calculations because 2014 emissions for the Anadarko Plant units are likely to be lower than 2008-2013 emissions.

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C. Western Farmers Could Not Have Reasonably Anticipated EPA's Error

The grounds for Western Farmer's objection arose after the public comment period. Before the Final Rule was issued, Western Farmers could not have expected or anticipated that EPA would set the Anadarko Plant unit allocations based on a *single* historic baseline year and *only CAMD* data. Both the Proposed and Final Rules call for EPA to set unit allocations using multiple historic baseline years[26] and EIA data-substitution. EPA did this in the Proposed Rule, but not in the Final Rule. What EPA did in the Final Rule looks like a clear technical error. It would be impracticable, if not impossible, for Western Farmers to have anticipated and submitted comment on an error that EPA *had not yet committed* during the public comment period, but committed for the first time in the Final Rule.

Western Farmers therefore had no meaningful opportunity to comment on the final allocations. EPA did not provide notice of or seek comment on the possibility of switching from *multiple* to *single* historic baseline years, or from using *both CAMD and EIA data* to *only CAMD* data. Had EPA done so, Western Farmers would have submitted comments that these changes would arbitrarily and unfairly penalize the Anadarko Plant units. As it stands, Western Farmers was caught by surprise by the new unit-level allocation data inputs. EPA may not "use the rulemaking process to pull a surprise switcheroo on regulated entities." *Envtl. Integrity Project*, 425 F.3d at 998.

EPA's data errors have left Western Farmers with a major and unexpected allowance shortfall for the 2017 ozone season. Correcting these errors is critical to Western Farmers' ability to plan for and achieve compliance with the CSAPR Update Rule, especially given the extremely near-term compliance timeframe for the 2017 ozone season.

D. EPA Should Correct These Technical Errors Through a Direct Final Rule

EPA should issue these technical corrections through a direct final rule as an alternative to full notice-and-comment rulemaking.[27] Direct final rules rely on the Administrative

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[26] The only difference between the Proposed and Final Rule was a one-year shift in the relevant baseline periods. Because 2015 data was not yet available, the Proposed Rule calculated allowance allocations based on a 2010-2014 heat input baseline period, and a 2007-2014 NOx emissions baseline period. The Final Rule uses a 2011-2015 heat input baseline period and a 2008-2015 NOx emissions baseline period. *See* Allocation TSD at 6.

[27] A direct final rule is "a rule that is issued in final form, without prior notice and comment, that becomes effective on a particular date unless adverse comment is submitted within a specified period of time." EPA Office of General Counsel, *Direct Final Rulemaking Guidance for EPA Rule Writers*, Attachment 1, § 2 (1998). Available at https://yosemite.epa.gov/oaqps/rdms.nsf/591caf4ab155e210852566de00539f57/c92ad1453ad5de6885256728006a0f30!OpenDocument ("Direct Final Rulemaking Guidance"). In conjunction with a direct final rule, EPA's typical practice is to simultaneously publish a separate, parallel proposed rule. If EPA receives significant adverse comments on the direct final rule, the Agency will withdraw the direct final rule and address the public comments in a subsequent final rule based on the parallel proposed rule. *Id.* at § 4. Western Farmers encourages EPA to act on this parallel tract to ensure the most efficient and timely resolution of EPA's data errors.

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Procedure Act's "good cause" exemption from notice-and-comment rulemaking,[28] while giving the Agency "the benefit of any public input that may unexpectedly surface." Direct Final Rulemaking Guidance at § 2 (citation omitted). EPA uses direct final rules for "noncontroversial rules where [the Agency does not] expect adverse comment," including routine or minor actions. *Id.* at §§ 4, 6. EPA previously has issued direct final rules under the CSAPR program. *See, e.g.*, *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 77 Fed. Reg. 10,342 (Feb. 21, 2012). Here, the corrections to EPA's allocation calculations are a non-controversial, minor action unlikely to attract adverse comment because they (1) would affect only a subset of units within a single state; and (2) are necessary to correct clear technical errors in EPA's application of the Final Rule's allocation methodology.

Further, time is of the essence. A direct final rule generally is a more efficient procedural mechanism than notice-and-comment rulemaking. The 2017 ozone season begins in just over five months. Western Farmers needs to get the correct amount of allowances on the books for their units as soon as possible in order to plan, and carry out, its compliance strategy for the 2017 ozone season.

II. OKLAHOMA STATE BUDGET

A. EPA's New Budget Calculation Method Arbitrarily Slashed Oklahoma's Budget

Oklahoma's budget decreased more than that of any other state between the Proposed and Final Rules, dropping by more than 25 percent, from 16,215 tons to 11,641 tons. Oklahoma's Final Rule budget is also about 49 percent lower than its 2016 ozone season budget, decreasing from 22,694 tons to 11,641 tons.[29] In contrast, most (15 out of 22 Group 2) CSAPR Update states saw their budgets *increase* in the Final Rule. Only six other states saw their budgets decrease, but none as significantly as Oklahoma.

The drastic reduction in Oklahoma's budget was driven by significant revisions EPA made to its budget calculation formula. Most critically, EPA introduced a NOx emission rate "delta" value that is derived from IPM. For certain states, including Oklahoma, the IPM-predicted emission rates are blatantly arbitrary. When plugged into EPA's new formula, they significantly *over-predict* available emissions reductions and significantly *under-predict* emissions levels. This results in an unrealistically low state budget. Western Farmers proposes a limited technical fix to EPA's formula that would help avoid this outcome while preserving EPA's Final Rule methodology.

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[28] 5 U.S.C. § 553(b)(3)(B) (Section 553's notice-and-comment requirement does not apply "when the agency for good cause finds . . . that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.").

[29] Under the Proposed Rule, this decrease was approximately 29 percent, a less drastic change.

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1. EPA's Changes to the State Budget Formula

EPA changed its state budget calculation formula significantly between the Proposed and Final Rules. Specifically, EPA introduced additional variables, including (i) an IPM-derived NOx emission rate "delta;" and (ii) an adjusted historic emission rate based on a newly-developed dataset.

In both the Proposed and Final Rule, EPA set state budgets as the minimum of either:

> (1) Historic actual emissions (2014 for the Proposed Rule; 2015 for the Final Rule); or
>
> (2) IPM-predicted 2017 emissions.

See 81 Fed. Reg. 74,548. What changed—significantly—between the Proposed and Final Rules is EPA's process for calculating IPM-predicted 2017 emissions.

For the Proposed Rule, EPA's method can be represented by the following formula:

> *IPM-predicted 2017 Emissions (tons) = (Historic Heat Input, 2014) x (IPM Emission Rate, 2017 $1,300/ton Cost Case)*[30]

For the Final Rule, EPA's new method requires a much more complex formula:

> *IPM-predicted 2017 Emissions (tons) = (Historic Heat Input, 2015) x [(Adjusted 2015 Emission Rate) - [(IPM Emission Rate, 2017 Base Case) - (IPM Emission Rate, 2017 $1,400/ton Cost Case)]]*[31]

According to EPA, both formulas reflect a basic method of "multiplying historical state-level heat input [*i.e.,* first parentheses on right-hand side of the equations] by state-level emission rates that reflect EGU NOX reduction potential [*i.e.*, second parentheses on right-hand side of the equations, highlighted in yellow]." *Id.* at 74,547. In the Proposed Rule, the "NOx reduction potential" emission rate was represented simply by an IPM Cost Case emission rate. In the Final Rule, the "NOx reduction potential" emission rate is represented by a more complex calculation

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[30] *See id.* at 74,547 ("[T]he proposed CSAPR Update put forward a methodology to set emission budgets by multiplying monitored historical state-level heat input by model-projected 2017 state-level emission rates. The monitored historical data were based on 2014, which was the most recent complete ozone season dataset at the time of the proposal.").

[31] *See id.* ("For the final CSAPR Update rule, the EPA is refining its methodology for establishing emission budgets that reflect EGU NOX reduction potential by using historical state-level NOX emission rates adjusted by modeled NOX reduction potential. Specifically, the final rule's approach applies the change in modeled 2017 state-level emission rates (the budget-setting base case 2017 projected rates minus the cost threshold modeling 2017 projected rates) to historical 2015 state-level NOX emission rates.")

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involving three variables: an adjusted historic emission rate, an IPM Base Case emission rate, and an IPM Cost Case emission rate. The only other step in the formulas is to multiply the "NOx reduction potential" emission rate by historic heat input to derive IPM-predicted 2017 emissions.

This updated formula reflects a new, multi-step process for calculating the NOx reduction potential emission rate that entails (1) first, calculating a NOx emission rate "delta," based on the difference between an IPM Base Case emission rate and an IPM $1,400/ton Cost Case emission rate; and (2) second, applying this "delta" to an adjusted historic emission rate. *See id.* at 74,548. This latter step requires assuming that "the potential of each state to improve its historical NOX rate by the same degree that it is projected to improve its NOX rate when moving between the budget-setting base case 2014 projection and cost threshold projection." *Id.* at 74,547. Finally, this "NOx reduction potential" emission rate is multiplied by historic heat input. The result is the final IPM-predicted 2017 emissions. As under the Proposed Rule, if this result is lower than historic actual emissions, then EPA bases the final state budget on the IPM-predicted 2017 emissions. If this result is higher than historic actual emissions, then EPA bases the final state budget on actual historic emissions.

Notably, EPA introduced several entirely new variables in the final state budget formula. EPA introduced an IPM Base Case emission rate value into the new formula, while the Proposed Rule included only an IPM $1,300/ton Cost Case emission rate. The new formula also required the Agency to develop an "adjusted historic dataset" in order to derive the adjusted 2015 emission rate values. *See id.* This adjusted dataset started with actual historic 2015 heat input and NOx emissions data. EPA then adjusted the actual historic data for three categories of "known changes in the power sector occurring between 2015 and 2017": (1) announced new selective catalytic reduction ("SCR") at existing EGUs; (2) announced coal-to-gas conversions; and (3) announced retirements. *Id.* According to the Agency, these adjustments "ensure that the emission budgets established by this rule reflect EGU NOX reductions both from already announced power sector changes and further EGU NOX reductions quantified in the EPA's EGU NOX reduction potential analysis." *Id.*[32]

2. Perverse IPM Result

EPA's new Final Rule budget-setting methodology yields the following results for Oklahoma:

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[32] EPA may have relied on inaccurate and over-simplified assumptions in calculating adjusted historic 2015 emission rates. For example, EPA's assumption that retirements necessarily will lead to a reduction in the state's average emission rate may not adequately account for the effects of intrastate or interstate load-shifting.

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Table 2. Comparison of 2015 Actual, 2015 IPM-Predicted, and 2017 IPM Base Case and Cost Case Results for Oklahoma Under the Final Rule.

	2015 Actual	2015 Actual, Adjusted	2017 IPM Base Case	2017 IPM (Final $1,400/ton)	CSAPR Budget (Final Rule)
Heat Input (MMBtu)	256,168,790	243,267,181	208,776,019	207,804,804	256,168,790
NOx (tons)	13,922	13,055	16,506	14,720	11,641
Emission Rate (lb/MMBtu)	0.109	0.107	0.158	0.142	0.091

The Perverse IPM Result is highlighted.

Importantly, IPM predicts that the 2017 Base Case emission rate for Oklahoma would be substantially *higher* than the historic actual or adjusted 2015 emission rate. In other words, IPM predicts that in a world without the CSAPR Update Rule, Oklahoma's NOx emission rate would increase from **0.107 lb/MMBtu in 2015 to 0.158 lb/MMBtu in 2017—*an increase of over 47 percent in just two years, without any predicted increase in heat input***. Similarly, IPM predicts that the 2017 $1,400/ton Cost Case emission rate would be substantially higher than the historic emission rate. So, even in a world *with* the CSAPR Update Rule, Oklahoma's NOx emission rate would increase from 0.107 lb/MMBtu in 2015 to 0.142 in 2017—an increase of over 32 percent in just two years, again without any predicted increase in heat input.

The IPM Base Case prediction that the 2017 NOx emission rate will increase to 0.158 lb/MMBtu is perverse, arbitrary, and demonstrably flawed. First, 0.158 lb/MMBtu is a significant increase from both the actual (0.109 lb/MMBtu) and adjusted (0.107 lb/MMBtu) 2015 emission rates. Second, the fact that EPA's adjusted 2015 emission rate is lower than the actual 2015 emission rate shows that EPA anticipates that announced SCRs, conversions, and retirements will *lower* the emission rate by approximately 0.002 lb/MMBtu between 2015 and 2017. This cuts against the IPM prediction of a significant rate increase. Third, CAMD data for 2016 shows a NOx emission rate of 0.101 lb/MMBtu for Oklahoma,[33] which is comparable to (even lower than) the actual or adjusted 2015 emission rates and nowhere near the 2017 IPM Base Case rate of 0.158 lb/MMBtu. Fourth, the IPM prediction would require rapid degradation and/or shut-down of existing NOx control technology in Oklahoma. The effectiveness of existing NOx controls is highly unlikely to degrade at the fast pace IPM predicts. Indeed, EPA has provided no apparent explanation for why the NOx emission rate would increase so significantly in just two years.

[33] *See* https://ampd.epa.gov/ampd/.

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For similar reasons, the IPM Cost Case prediction that the 2017 NOx emission rate will increase to 0.142 lb/MMBtu also is arbitrary and demonstrably flawed. Further, comparing the IPM Cost Case emission rate with the emission rate resulting under Oklahoma's final CSAPR budget indicates that EPA does not trust its own model. If IPM were relatively accurate, the IPM Cost Case emission rate (0.142 lb/MMBtu) would be closer to the final budget value (0.091 lb/MMBtu), *not more than 55 percent greater*. The fact that EPA does not rely directly on the IPM Cost Case emission rate to calculate state budgets (consistent with the Proposed Rule) shows that EPA is aware of the questionable reliability of direct use of IPM emission rate outputs. Nonetheless, EPA relied on these IPM outputs—which are patently arbitrary in Oklahoma's case—in setting state budgets.

3. Oklahoma's Budget Calculation

The Perverse IPM Result led to an unrealistically and arbitrarily low budget for Oklahoma. Critically, the Perverse IPM Result overestimates the amount of emissions reductions available in the state. That is, because the IPM Base Case emission rate is unrealistically high, the emission rate "delta" between the 2017 IPM Base Case and Cost Case also is unrealistically high.[34] This error—a NOx emission rate "delta" that is too high—then carries through the entire calculation, ultimately resulting in final IPM-predicted 2017 emissions that are too low. For Oklahoma, these IPM-predicted 2017 emissions were lower than its historic 2015 emissions. Accordingly, EPA set Oklahoma's final budget equal to these arbitrary and inaccurate IPM-predicted emissions.

Below is a step-by-step overview of EPA's calculation for Oklahoma. Values affected by the Perverse IPM Result are highlighted:

Values that are **too high** because of the Perverse IPM Result are highlighted in **green**.

Values that are **too low** because of the Perverse IPM Result are highlighted in **red**.

Step 1. Calculate ***NOx Emission Rate "Delta"*** = *(IPM Emission Rate, 2017 Base Case) - (IPM Emission Rate, 2017 $1,400/ton Cost Case)*

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[34] Even if IPM accurately predicted the relative difference between the Base Case and Cost Case emission rates, it would be inappropriate to apply this absolute "delta" value directly to an actual emissions rate. To take a simplified, extreme example: State O has an actual emissions rate of 0.1 lb/MMBtu. IPM predicts a Base Case emission rate of 0.3 lb/MMBtu and a Cost Case Emission rate of 0.2 lb/MMBtu. The "delta" between the IPM rates is 0.1 lb/MMBtu. Applying this "delta" to the historic emissions rates leaves you with an emission rate of 0.0 lb/MMBtu! The moral of the story is that if IPM-predicted rates are unrealistically high, the "delta" between these values is not something that can just be applied to a real emission rate. Indeed, in extreme cases, this "delta" can even be equal to or even bigger than the real emission rate. But if the IPM Base Case rate was effectively "capped" at the historic emission rate (0.1 lb/MMBtu in our example), there is no way the "delta" between the two IPM rates could be greater than the historic rate (the "delta" could only range from 0.0 lb/MMBtu to 0.1 lb/MMBtu in our example). This "capping" is effectively what the proposed scaling fix described below would accomplish.

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= *(**0.158** lb/MMBtu) - (**0.142** lb/MMBtu)*

= ***0.016 lb/MMBtu***

In Step 1, the calculated "delta" value (0.016 lb/MMBtu) is arbitrarily high due to the Perverse IPM Result. Western Farmer's analysis, discussed in the following section, indicates that a more realistic value would be closer to 0.011 lb/MMBtu—*over 30 percent lower than the current value.* This means that EPA likely has significantly overestimated the amount of emissions reductions available in Oklahoma.

Step 2. Calculate ***"NOx Reduction Potential" Emission Rate*** = *(Adjusted 2015 Emission Rate) - (NOx Emission Rate "Delta)"*

= *(**0.107** lb/MMBtu) - (**0.016** lb/MMBtu)*

=***0.091** lb/MMBTu*

In Step 2, applying the too-high "delta" value reduces the adjusted 2015 emission rate by too much—*i.e.*, by an amount greater than what is achievable in reality. This means the resulting "NOx Reduction Potential" emission rate (0.091 lb/MMBtu) is lower than what it should be had EPA relied on a more realistic "delta." Indeed, an emission rate of 0.091 lb/MMBtu is below even the rate achieved by new SCRs (0.10 lb/MMBtu) and NOx combustion controls (0.15 lb/MMBtu, at best). Achieving this rate on a statewide average basis likely would require shutting down fossil-fuel fired EGUs and constructing a sufficient number of new alternative energy sources to replace generation capacity by 2017.

Step 3. Calculate ***IPM-predicted 2017 emissions*** = *(Historic Heat Input, 2015) x ("NOx Reduction Potential" Emission Rate*

= *(**256,168,790** MMBtu) x (**0.091** lb/MMBtu) / 2000*

= **11,641** tons

In Step 3, multiplying the too-low "NOx reduction potential" emission rate by historic heat input results in IPM-predicted 2017 emissions that are too low—again, lower than what is achievable in reality. Oklahoma's final state budget of 11,641 tons likely is unattainable.

To correct the errors associated with the Perverse IPM Result, EPA must adjust the IPM emission rates in Step 1 to more realistic values.

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B. Proposed State Budget Fix

Western Farmers proposes a limited adjustment to EPA's budget calculation for Oklahoma and other states affected by the Perverse IPM Result.[35] The proposal retains the Final Rule's state budget calculation formula. However, it calls for an additional "scaling" step for states with the Perverse IPM Result ("Scaling Fix"). This Scaling Fix allows EPA to keep the Final Rule's current methodology, but ensures that the methodology is not applied in an arbitrary manner that achieves unrealistic results. *See* Appendix B-1 for detailed calculations.

The proposed Scaling Fix would be applied during Step 1 of EPA's formula (calculation of NOx emission rate "delta"). It has two components:

> (1) **Scaling 2017 IPM Base Case Emission Rate to Reflect Actual 2015 Data.** Both 2017 IPM Base Case NOx emissions and 2017 IPM Base Case heat input values would be scaled to actual 2015 values. For Oklahoma, NOx emissions would be scaled from 16,506 tons to 13,922 tons. Similarly, heat input would be scaled from 208,776,019 MMBtu to 256,168,790 MMBtu. (Currently, IPM illogically predicts that emissions will increase while heat input will decrease between 2015 and 2017. This makes predicted NOx emission rates unachievable if fuel consumption remains constant in reality. The Scaling Fix reflects relatively flat levels of fuel consumption and emissions over the next two years.) Oklahoma's scaled 2017 IPM Base Case emission rate would be **0.109 lb/MMBtu**.
>
> (2) **Scaling 2017 IPM Cost Case Emission Rate, Based on a Scaling Factor Derived From Part 1.** Both 2017 IPM Cost Case NOx emissions and 2017 IPM Cost Case heat input values would be scaled by a scaling factor derived from part one—*i.e.*, by the same relative amount that NOx emissions and heat input were scaled for the IPM Base Case emission rate. For Oklahoma, the scaling factor would be 0.84 for NOx emissions and 1.23 for heat input. Accordingly, NOx emissions (for the 2017 IPM $1,400/ton Cost Case) would be scaled from 14,720 tons to 12,353 tons. Heat input would be scaled from 207,804,804 MMBtu to 255,435,708 MMBtu. Oklahoma's scaled 2017 IPM $1,400/ton Cost Case emission rate would be **0.095 lb/MMBtu**.

Then, the NOx emission rate "delta" (Step 1 of EPA's formula) would be calculated based on these scaled IPM emission rates. For Oklahoma, this scaled "delta" value would be **0.011 lb/MMBtu**, *about 31 percent lower than the "delta" value used in the Final Rule (0.016 lb/MMBtu)*. The rest of EPA's formula (Steps 2 and 3) would then be applied as currently described in the Final Rule. This should result in a final budget for Oklahoma of 12,309 tons, or

---

[35] Western Farmers' analysis indicates that the Perverse IPM Result negatively affects the budgets for six other states: Indiana, Kansas, Michigan, Missouri, Mississippi, and Texas.

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about 668 additional tons compared to the Final Rule budget. *See* Table 4 below; *see also* Appendix B-1.[36]

C. The Proposed State Budget Fix Would Preserve Air Quality Benefits

The proposed Scaling Fix would preserve the Final Rule's air quality benefits. Western Farmers analyzed the impact of applying the Scaling Fix to all seven states whose Final Rule budgets are negatively affected by the Perverse IPM Result on reductions of ozone design values (average and maximum) in 2017 at 19 downwind nonattainment and maintenance receptors.[37] As Table 3 shows, these results indicate no change in average reduction of ozone average design values, and a minimal decrease in average reduction of ozone maximum design values, from the Final Rule. *See* Appendix C-1 for detailed underlying calculations. If the Scaling Fix is applied *only* to Oklahoma, then there is *no change* in average reduction of ozone average or maximum design values. *See* Appendix C-2 for detailed underlying calculations.

Table 3. Impact of Scaling Fix on Average Ozone Reduction at 19 Nonattainment and Maintenance Receptors, Based on AQAT.

	Historic Actual 2015 (7 States)	Final Rule	Scaling Fix (7 States)	Scaling Fix (Oklahoma Only)
Avg. Reduction of Ozone Average Design Values (ppb)	0.15	0.28	0.28	0.28
Avg. Reduction of Ozone Maximum Design Values (ppb)	0.16	0.29	0.28	0.29

Further, the Scaling Fix would not dramatically increase state budgets. Table 4 shows the impact of applying the Scaling Fix to the seven affected states. As shown, the Scaling Fix generally would raise state budgets to levels somewhere in-between current Final Rule budget and historic emissions levels. For four states, the Scaling Fix would increase Final Rule budgets by less than 100 tons. Oklahoma is the only state whose budget would increase by more than

[36] Appendix B-2 shows updated Oklahoma unit allocation calculations using the EIA data-substitution described in Part I *and* the proposed state budget Scaling Fix. Under this method, the Anadarko Plant units would receive 55, 56, and 60 units each (171 units combined).

[37] Western Farmers used the same AQAT-based methodology that EPA describes in the Regulatory Impact Analysis (consistent with the Ozone Transport Analysis Final Rule TSD and the preamble to the CSAPR Update Rule). *See* Regulatory Impact Analysis at 3-9 to 3-10.

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500 tons. Overall, the Scaling Fix would increase all seven state budgets by a combined total of just over 1,400 tons:[38]

Table 4. Impact on State Budgets of Applying the Proposed Scaling Fix.

State	Historic Actual 2015 Emissions (tons)	Final Rule Budget (tons)	Scaling Fix Budget (tons)	Change (Final Rule and Scaling Fix Budget) (tons)
Indiana	36,353	23,303	23,377	**74**
Kansas	8,136	8,027	8,027	**0**
Michigan	21,530	17,023	17,377	**354**
Missouri	18,855	15,780	15,798	**18**
Mississippi	6,438	6,315	6,336	**21**
Oklahoma	13,922	11,641	12,309	**668**
Texas	55,409	52,301	52,591	**290**
Total	**160,643**	**134,390**	**135,815**	**1,425**

D. Western Farmers Could Not Have Reasonably Anticipated the Changes in EPA's Methodology

Western Farmers' could not have reasonably anticipated that EPA would pull a "surprise switcheroo" and change its state budget calculation methodology so significantly between the Proposed and Final Rules, slashing Oklahoma's budget by more than 25 percent. In particular, EPA did not provide notice that the Agency would change its formula for calculating model-predicted emissions to include (1) adjusted historic emission rates based on a newly-developed dataset; or (2) IPM-derived emission rate "deltas" that rely on the difference between IPM Base

[38] Western Farmers' preliminary analysis indicates that applying the Scaling Fix to all 22 CSAPR Update states likely would decrease the budgets for 14 out of the 15 states without the Perverse IPM Result (all states but Virginia). However, further state-by-state scrutiny would be needed to ascertain the impact of the Scaling Fix on all CSAPR Update states. Further, Western Farmers notes that the Scaling Fix is specifically designed to address a modeling flaw that is common to a small subset of states. The Scaling Fix may not be appropriate to apply to states without the Perverse IPM Result.

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Case and IPM Cost Case emission rates.[39] Nor did EPA provide notice that it would finalize a methodology that entailed applying IPM-derived emission rate "deltas" to historic emission rates.[40] Had EPA done so, Western Farmers would have analyzed and submitted comments on the impact on Oklahoma's budget of EPA's unrealistic and arbitrary assumptions, including the Perverse IPM Result.

EPA characterizes the changes in the Final Rule's formula as a "refinement" to the proposed approach. *See* 81 Fed. Reg. 74,547.[41] However, the alterations go far beyond mere refinements. First, as EPA acknowledges, the Agency had to develop an adjusted historical dataset to derive the adjusted historic emission rates. *Id.* Second, EPA had to add at least two additional steps to its calculation methodology. The Proposed Rule's methodology consisted of one basic step: multiply historic heat input by an IPM Cost Case emission rate. The Final Rule's methodology is a complex, three-step process: (1) calculate an emission rate "delta" by subtracting an IPM Cost Case emission rate from an IPM Base Case emission rate; (2) calculate a "NOx reduction potential" emission rate by subtracting this "delta" from an adjusted historic emission rate; and (3) calculate IPM-predicted 2017 emissions by multiplying the "NOx reduction potential" emission rate by historic heat input. *Id.* at 74,548. This three-step process, based in part on a newly-developed historical dataset, is no logical outgrowth of the Proposed Rule's single-step process that did not rely on "adjusted" historic data. For these reasons, EPA must reconsider, at least in the proposed limited fashion, the CSAPR Update Rule.

CONCLUSION

In sum, Western Farmers requests that EPA recalculate (1) unit-level allowance allocations for the Anadarko Plant units, using the data-substitution method called for in Final Rule and based on monthly (not annual), reported (not adjusted) data; and (2) Oklahoma's state budget, using the proposed limited "scaling" adjustment to the Final Rule's existing calculation methodology to ensure arbitrary IPM outputs do not distort the calculation.

---

[39] Notably, the Proposed Rule include did not include an IPM 2017 Base Case emission rate in its formula, only an IPM Cost Case emission rate. The IPM 2017 Base Case emission rate is the primary driver of the Perverse IPM Result.

[40] While EPA sought comment "on all aspects of quantifying state emissions budgets reflecting upwind obligations," 80 Fed. Reg. 75,739, it is unreasonable to expect that commenters could have anticipated and commented on *all* possible permutations of EPA budget calculation formula. EPA's blanket request for comment does not amount to notice that the Agency would introduce new variables, complex calculation steps, or underlying datasets—much less all three.

[41] EPA further asserts that the "final rule methodology for setting emission budgets reflects the CSAPR Update proposal in that it retains the approach of multiplying historical state-level heat input by state-level emission rates that reflect EGU NOX reduction potential." *Id.* As EPA seems to implicitly acknowledge, any methodological similarities between the two approaches exist at only a very high level. Critically, as discussed above, EPA's approach for determining "state-level emission rates that reflect EGU NOX reduction potential" changed dramatically between the Proposed and Final Rule.

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Dated: December 22, 2016

Respectfully submitted,

/x/ Brian Hobbs

Brian Hobbs

VP, Legal & Corporate Svcs.

Western Farmers Electric Cooperative

Enclosures (CD-Rom):

Appendix A-1:	**Unit-Level Allocations with EIA Substitution (Final Rule)**
Appendix A-2:	**EIA Data Substitution Calculations**
Appendix B-1:	**Revised Appendix E State Budgets (Scaling Fix)**
Appendix B-2:	**Revised Unit-Level Allocations with EIA Substitution (Scaling Fix)**
Appendix C-1:	**AQAT (Scaling Fix -- 7 States)**
Appendix C-2:	**AQAT (Scaling Fix -- Oklahoma Only)**

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To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Craig Glidden
Sent: Fri 4/28/2017 9:34:48 PM
Subject: Follow Up to Meeting with Administrator Pruitt
Attachment 1 - Gov Brown Letter to Auto Manufacturers.pdf
Attachment 2 - CARB 24MAR17 Board hearing transcript.pdf
Attachment 3 - 24MAR17 CARB Board hearing 2022-2025 press release.pdf

Dear Samantha – Please convey my thanks to Administrator Pruitt for the good discussion we had on Wednesday regarding issues impacting the automotive industry. I wanted to provide you with three items referred to during that meeting:

1. Attachment 1 - March 15, 2017 letter from Gov. Brown to Alliance of Automobile Manufacturers;

2. Attachment 2 - Transcript of the March 24, 2017 public hearing of the California Air Resources (the pinpoint cite referred to is on page 184-5 of 347); and

3. Attachment 3 - Copy of the California Air Resources Board News Release of March 24, 2017.

To facilitate the recommencement of action on the Midterm Review of the 2022 – 2025 standards, we suggest the following immediate next steps.

- We suggest that the EPA, in coordination with NHTSA, re-open the public docket (EPA-HQ-OAR-2015-0827) on the draft Technical Assessment Report for 60 days and commence the process for reconsidering the Final Determination on a public timeline. We stand ready to work with your team as you coordinate with NHTSA.

- We suggest that Administrator Pruitt, along with Secretary Chao, convene a meeting of relevant stakeholders, including California, to find common ground as we simultaneously advance the formal process of the Midterm Review.

We appreciate very much the time of the Administrator and his team for our discussion and we look forward to working with you and all relevant stakeholders to advance the process. Many thanks, Craig

Craig B. Glidden

Executive Vice President & General Counsel
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GENERAL MOTORS

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MEETING

STATE OF CALIFORNIA

AIR RESOURCES BOARD

RIVERSIDE COUNTY ADMINISTRATIVE CENTER

BOARD OF SUPERVISORS CHAMBERS

FIRST FLOOR

4080 LEMON STREET

RIVERSIDE, CALIFORNIA

FRIDAY, MARCH 24, 2017

8:43 A.M.

JAMES F. PETERS, CSR
CERTIFIED SHORTHAND REPORTER
LICENSE NUMBER 10063

A P P E A R A N C E S

BOARD MEMBERS:

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Ms. Sandra Berg, Vice Chair

Dr. John Balmes

Mr. Hector De La Torre

Mr. John Eisenhut

Senator Dean Florez

Ms. Judy Mitchell

Mrs. Barbara Riordan

Supervisor Phil Serna

Dr. Alex Sherriffs

Professor Daniel Sperling

Ms. Diane Takvorian

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Ms. Edie Chang, Deputy Executive Officer

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Ms. Ellen Peter, Chief Counsel

Ms. Veronica Eady, Assistant Executive Officer

Ms. La Ronda Bowen, Ombudsman

Ms. Emily Wimberger, Chief Economist

Ms. Analisa Bevan, Assistant Division Chief, ECARS

Mr. Pippin Brehler, Senior Attorney, Legal Office

A P P E A R A N C E S C O N T I N U E D

STAFF:

Mr. Joshua Cunningham, Branch Chief, ECARS

Ms. Annette Hebert, Division Chief, ECARS

Ms. Alexandra Kamel, Attorney, Legal Office

Mr. Jeffrey Lidicker, Air Resources Engineer, ECARS

Mr. Pippin Mader, Air Resources Engineer, Monitoring and Laboratory Division

Mr. Mike McCarthy, Chief Technology Office, ECARS

Ms. Anna Wong, Staff Air Pollution Specialist, Emissions Compliance, Automotive Regulations and Sciences Division(ECARS)

ALSO PRESENT:

Ms. Kitty Adams, Adopt a Charger

Ms. Fariya Ali, Pacific Gas & Electric

Mr. Marco Anderson, Southern California Association of Governments

Mr. Thomas Ashley, Greenlots

Ms. Betty Barberena, SALEF

Ms. Sutida Bergquist, Professional Engineers in California Government

Mr. John Boesel, CalStart

Mr. John Bozzella, Association of Global Automakers

Dr. Rasto Brezny, Manufacturers of Emission Controls Association

Mr. Tom Cackette, Environmental Defense Fund

Mr. Fernando Cazeras, Trust for Public

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A P P E A R A N C E S C O N T I N U E D

ALSO PRESENT:

Ms. Patricia Chen, LA Metro

Mr. Carlos Cortes, BTC Power, Inc.

Mr. John Dangberg, City of Sacramento, Mayor Darrell Steinberg

Mr. Steven Douglas, Alliance of Automobile Manufacturers

Ms. Allis Druffel, California Interfaith Power & Light

Mr. Harvey Eder, Public Solar Power Coalition

Mr. William Elrick, California Fuel Cell Partnership

Ms. Leah Feldon, Oregon Department of Environmental Quality

Mr. Steve Flynn, New York Department of Environmental Conservation

Mr. Chet France, Environmental Defense Fund

Ms. Genevieve Gale, Central Valley Air Quality Coalition

Mr. Larry Greene, Sacramento Metropolitan Air Quality Management District

Mr. Tom Gross, Southern California Edison

Ms. Irene Gutierrez, Natural Resources Defense Counsel

Ms. Cassie Halls, Shared-Use Mobility Center

Ms. Christina Heartquist, Consumer Federation of America

Ms. Megan Herzog, Conservation Law Fund

Mr. Henry Hogo, South Coast Air Quality Management District

Ms. Laurie Holmes, Motor and Equipment Manufacturers' Association

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A P P E A R A N C E S C O N T I N U E D

ALSO PRESENT:

Ms. Bonnie Holmes-Gen, American Lung Association

Mr. Merlyn Hough, Lane Regional Air Protection Agency

Dr. Karen Jacpor, American Lung Association

Mr. Brendan Jones, Electrify America

Ms. Michelle Kinman, Environmental California Research & Policy Center

Ms. Christine Kirby, Massachusetts Department of Environmental Health

Mr. Rob Klee, Connecticut Department of Energy and Environmental Protection

Rev. Earl Koteen, Sunflower Alliance

Dr. Chris Langdon, Drucker School, Claremont Graduate University

Mr. Joel Levin, Plug In America

Mr. Mike Lewis, Pearson Fuels

Ms. Amy Lilly, Mercedez-Benz

Mr. Michael Lord, Toyota

Mr. Nicholas Lutsey, International Council of Clean Transportation

Mr. Bill Magavern, Coalition for Clean Air

Ms. Lisa McGhee, San Diego Airport Parking Company

Ms. Jennifer Moeller, Moms Clean Air Force

Mr. Ken Morgan, Tesla

Mr. Simon Mui, Natural Resources Defense Counsel

Ms. Hilary Norton, FAST LA

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A P P E A R A N C E S C O N T I N U E D

ALSO PRESENT:

Mr. Graham Noyes, Low Carbon Fuels Coalition

Ms. Gloria Ohland, More LA

Ms. Kathryn Phillips, Sierra Club of California

Ms. Michelle Pierce

Ms. Julia Rege, Global Automakers

Dr. David Reichmuth, Clean Vehicles Program

Ms. Alisa Reinhardt, California New Car Dealers Association

Ms. Susana Reyes, City of LA, Office of Mayor Garcetti

Ms. Ashley Rosia-Tremonti, City of San Diego

Mr. Craig Scott, Toyota

Mr. David Schembri, EVgo

Ms. Anne Smart, Charge Point

Ms. Susana Reyes, City of Los Angeles, Office of Mayor Garcetti

Mr. John Shears, Center for Energy Efficiency and Renewable Technologies

Mr. Cory Shumaker, California Hydrogen Business Council

Ms. Anne Smart, Charge Point

Mr. Matt Solomon, Northeast States for Coordinated Air Use Management

Mr. Joe Sullivan, IBEW/NECA

Mr. Mike Swords, Los Angeles Cleantech Incubator

Mr. Ricky Teebay, County of Los Angeles

A P P E A R A N C E S C O N T I N U E D

ALSO PRESENT:

Ms. Eileen Tutt, California Electric Transportation Coalition

Mr. Desmond Wheatley, Envision Solar

Mr. John White, Center for Energy Efficiency and Renewable Technologies, Hydrogen Business Council

Mr. Beau Whiteman, Tesla

Mr. Jerard Wright, BizFed

Mr. Andy Wunder, CERES

Mr. Kevin Zheng, SemaConnect

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1 P R O C E E D I N G S
2 CHAIR NICHOLS: Good morning. If you could take
3 your seats, please.
4 I know there are people still making their way
5 through the security line, but I don't want to keep the
6 rest of the group waiting either.
7 Good morning and welcome. And we'll go through
8 our opening drill on Day 2 of the March Public Meeting of
9 the Air Resources Board.
10 So let's please rise for the Pledge of
11 Allegiance.
12 (Thereupon the Pledge of Allegiance was
13 Recited in unison.)
14 CHAIR NICHOLS: There's a nice photo in one of
15 the publications from yesterday's meeting that shows Sandy
16 and me and Barbara up in front, and makes it look as
17 though we've taken over the county of Riverside.
18 (Laughter.)
19 CHAIR NICHOLS: So in case anybody is
20 wondering --
21 (Laughter.)
22 CHAIR NICHOLS: -- we're only temporary visitors.
23 But we're very grateful to Riverside County for lending us
24 their board hearing room once again. It's a good place to
25 meet.

1 So if we can have the clerk please call the roll.
2 BOARD CLERK McREYNOLDS: Dr. Balmes?
3 BOARD MEMBER BALMES: Here.
4 BOARD CLERK McREYNOLDS: Mr. De La Torre?
5 BOARD MEMBER DE LA TORRE: Here.
6 BOARD CLERK McREYNOLDS: Mr. Eisenhut?
7 BOARD MEMBER EISENHUT: Here.
8 BOARD CLERK McREYNOLDS: Senator Florez?
9 Assembly Member Garcia?
10 Supervisor Gioia?
11 Senator Lara?
12 Ms. Mitchell?
13 BOARD MEMBER MITCHELL: Here.
14 BOARD CLERK McREYNOLDS: Ms. Riordan?
15 BOARD MEMBER RIORDAN: Here.
16 BOARD CLERK McREYNOLDS: Supervisor Roberts?
17 Supervisor Serna?
18 BOARD MEMBER SERNA: Here.
19 BOARD CLERK McREYNOLDS: Dr. Sherriffs?
20 BOARD MEMBER SHERRIFFS: Over here.
21 (Laughter.)
22 BOARD CLERK McREYNOLDS: Professor Sperling?
23 BOARD MEMBER SPERLING: Here.
24 BOARD CLERK McREYNOLDS: Ms. Takvorian?
25 BOARD MEMBER TAKVORIAN: Here.

1 BOARD CLERK McREYNOLDS: Vice Chair Berg?
2 VICE CHAIR BERG: Here.
3 BOARD CLERK McREYNOLDS: Chair Nichols?
4 CHAIR NICHOLS: Here.
5 BOARD CLERK McREYNOLDS: Madam Chair, we have a
6 quorum.
7 CHAIR NICHOLS: That's great.
8 (Laughter.)
9 CHAIR NICHOLS: There really is no way we can
10 move Dr. Sherriffs in?
11 Wait, there's --
12 BOARD MEMBER DE LA TORRE: I'll switch.
13 BOARD MEMBER BALMES: He's over here in the left
14 bank.
15 CHAIR NICHOLS: I know.
16 BOARD MEMBER SHERIFFS: Look at all the
17 microphones I get.
18 (Laughter.)
19 CHAIR NICHOLS: All right. Well, we'll just --
20 we'll remember to bring you in.
21 Good morning, everybody.
22 A couple of usual opening announcements. If
23 you're planning on testifying on any of the items on
24 today's agenda, we appreciate it if you would fill out
25 your Request-to-Speak form in advance on one of the cards

1 outside or get it from the clerk. And she puts the list
2 together so it makes it much easier for us to know what's
3 going on.
4 We're planning on imposing our usual 3-minute
5 limit on speakers. Although, yesterday we got to the
6 point where we actually had to go down to a 2-minute limit
7 at the very end of the day, and it didn't work out too
8 badly. But by that time everybody was feeling more like
9 compressing their comments, so it worked out pretty well.
10 For safety reasons, I'll have to ask you to note
11 the exits at the rear of the room. In the event of an
12 alarm, we're to exit the building through those exits --
13 exit doors and go out of the building until there's an
14 all-clear signal.
15 And I believe that as far as opening comments,
16 that would be it.
17 We're really happy to kick off the day with
18 something unusual and very special; and that is a
19 recognition of ARB staff. We don't often take time during
20 our public meetings for any of the relatively routine
21 events that we hold where we single out people for special
22 merit during the course of the year. But this is a
23 recognition of something that was truly remarkable in the
24 history of ARB, and that was the breaking of the case on
25 the international scandal that we now know as the

1 Volkswagen defeat device.
2 Under the Clean Air Act, as everyone knows who's
3 here, California gets to set and enforce its own vehicle
4 standards. And it's thanks to this provision of the Clean
5 Air Act that Volkswagen's actions were actually uncovered.
6 The in-use compliance program that ARB operates
7 ensures that cars sold in California are still providing
8 emissions controls years after they leave the showroom.
9 We're fortunate that dozens of scientists, technicians,
10 engineers, and lawyers who are at the top of their fields
11 come to work here and are engaged in this and some of our
12 other programs.
13 We are also doubly blessed that our engineers
14 exhibited an unparalleled level of commitment and
15 dedication along with the intellectual imagination and
16 problem-solving skills to detect the defeat device that
17 had remained hidden from the eyes of other agencies around
18 the world, although it was hidden in plain sight for
19 almost a decade. I'm sure Volkswagen may have thought
20 that their engineers were able to keep this illegal
21 software hidden forever. But they didn't consider that
22 one day they would have to come face to face with the
23 collective ingenuity of our California engineers.
24 This case truly shows I think some of the best at
25 ARB, the dedicated professional staff from various

1 professions, using sound science and strong technical
2 know-how, to ensure that our programs and policies
3 actually deliver on the promise of cleaner air. It's not
4 just about writing regulations. It's about implementing
5 them and enforcing them.
6 ARB's success is not only shared with all of the
7 Californians who benefit from our programs, but it also I
8 think helps to achieve recognition for the professions
9 that they come from, particularly the engineering
10 professions, many of whom work in other parts of State
11 government and don't always get the opportunity to be
12 recognized.
13 So today, we are very honored that the
14 Professional Engineers in California Government
15 organization is recognizing our staff engineers from the
16 Volkswagen case with their highest honor. And to present
17 these awards to the engineers involved in uncovering the
18 Volkswagen defeat devise we are joined by President Elect
19 Sutida Bergquist of the Professional Engineers in
20 California Government. Following a brief introduction,
21 each of the awardees will rise to be recognized as their
22 names are called. And I ask that you please hold your
23 applause till the end of the roll call.
24 So I would now like to invite Ms. Bergquist to
25 the podium.

1 MS. BERGQUIST: Good morning. My name is Sutida
2 Bergquist. I am the president elect of the Professional
3 Engineers in California Government. I want to thank the
4 Air Resources Board and Chair Mary Nichols for allowing me
5 to speak briefly on behalf of our organization which
6 represents 13,000 State engineers.
7 Each year we honor the important work of the
8 employees we represent with our Professional Achievement
9 Award.
10 For 2016, PECG has decided be bestow this award
11 to more than 80 ARB engineers and related staff on the
12 board's Volkswagen Diesel Cheating Detection Team.
13 We have never given the award to so many people
14 at one time, but the impact of the team's services is
15 without precedent.
16 Two years ago the ARB asked a question: Why did
17 Volkswagen's so-called clean diesel engine pass smog
18 tests, but when driven the cars with the engine threw out
19 pollution that exceeded legal limits?
20 That question and the relentless pursuit of the
21 answer by VW Diesel Cheating Detection Team forced one of
22 the world's largest automakers to admit it's used
23 sophisticated software to trick emissions tests. Last
24 year, Volkswagens recalled 482,000 vehicles sold in
25 America. Another 8.5 million cars in Europe were

1 affected. At least six Volkswagen executives has been
2 charged with crimes. The company has admitted to several
3 crimes and has paid billions of dollars in fines.
4 France and Italy are investigating emissions from
5 diesel Volkswagens sold in their country.
6 And just last week German authorities searched
7 Volkswagen and Audi offices and ceased company records, as
8 the legal probes into the case widen again.
9 And it all started because of ARB's persistent
10 investigation.
11 Who knows how much damage was avoided because you
12 guarded the public good. Who knows how long the scheme
13 might have continued to secretly foul the environment and
14 harm public health if you weren't watching. Who knows how
15 many -- how many more of those vehicles would be on the
16 road right now churning up to 40 times the pollution that
17 the law allows had you not intervened.
18 Your work on this case has displayed to the world
19 our California government at its best.
20 I am honored to present the 2016 Professional
21 Achievement Award today. And I am aware that some of them
22 are some of the folks that work on this in Sacramento. So
23 I want to give the shout out to them as well, that because
24 of you it showcases the work that State engineers and
25 related professions perform every day, most of the time

with a little public recognition and sometimes with plenty of private pushback.

We will recognize employees individually at lunch in El Monte. In the moment, we will ask everyone on the team to stand and come forward for a photo with the Board.

Congratulations from PECG, and thank you service not only to our great state but to the world.

Thank you.

(Applause.)

MS. BERGQUIST: Can you stand up to please be recognized.

(Standing applause.)

(Photo taken.)

CHAIR NICHOLS: That was a fun way to start the day.

That photo is going to be one for the ages, really.

All right. Everybody can get settled.

The next item on today's agenda is a report from the staff on California's Midterm Review of the Advanced Clean Cars regulations.

Just a bit of history here. In January 2012, the Board approved regulations to significantly reduce both criteria pollution and greenhouse gas emissions from passenger vehicles and light-duty trucks for the 2015 and

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later-model years.

As part of this package, the Board also ramped up the requirements for zero-emission vehicles in California starting in the 2018 model year.

At the conclusion of the January 2012 hearing, the Board directed staff to examine a number of outstanding issues pertaining to those regulations and report back to us as part of a midterm review.

The first issue: The appropriateness of the 2022 through 2025 model year national -- national greenhouse gas standards included a commitment for ARB to participate with the U.S. EPA and the National Highway Traffic Safety Administration in a federal midterm evaluation.

The second issue centered around the feasibility and timing for implementing California's one milligram per mile particulate matter standard for 2025 model year light-duty vehicles.

And a third area of issues included a review of the appropriateness of the zero-emission vehicle requirements for 2018 and subsequent model years.

The results of staff's assessment were published in a comprehensive midterm report released on January 18th, and they will be summarized in today's presentation.

Mr. Corey, would you please introduce this item.

EXECUTIVE OFFICER COREY: Yes. Thanks, Chair

1 Nichols.
2 California's was first to adopt light-duty
3 greenhouse gas emission standards. They began in model
4 year 2009. Since federal adoption of comparable standards
5 starting in 2012, we participated in a national program
6 provided California does not lose ground towards attaining
7 its own emission requirements and goals. To that end,
8 California added regulatory flexibility that has allowed
9 California vehicles to certify to national greenhouse gas
10 standards as an alternative to our own standards since
11 model year 2020 -- rather 2012.
12 It's worth mentioning that California neither
13 relinquished nor accepted any limit to authority to
14 control greenhouse gas emissions from motor vehicles by
15 agreeing to this regulatory flexibility.
16 Before we start the staff presentation on
17 California's midterm review, I'd like to mention the
18 conclusions of the federal midterm evaluation. On
19 November 30th, 2016, U.S. EPA proposed to determine that
20 the 2022 through 2025 model year passenger vehicle
21 greenhouse gas standards remain appropriate and no changes
22 to the regulations are warranted.
23 After considering all comments received in
24 response to the proposed determination, U.S. EPA confirmed
25 its findings in a final determination which was signed by

1 the administration on January 12th, 2017.
2 This determination is consistent with ARB staff's
3 own findings in our consideration of public comments that
4 supports maintaining the greenhouse gas standards and
5 retaining the team to comply regulatory flexibility for
6 2017 through 2025 model years as an alternative to our own
7 standards.
8 Staff will also present the results of our
9 studies to address the Board's questions on the
10 feasibility of the one milligram per mile particulate
11 matter standard for light-duty vehicles and the
12 appropriateness of a current zero-emission vehicle
13 requirements.
14 Pippin Mader of the Monitoring and Laboratory
15 Division will now start the staff's presentation, followed
16 by Anna Wong of the Emissions Compliance Automotive
17 Regulations and Science Division.
18 And with that, Pippin.
19 (Thereupon an overhead presentation was
20 Presented as follows.)
21 AIR RESOURCES ENGINEER MADER: Thank you,
22 Mr. Corey. Good morning, Chair Nichols and members of the
23 Board.
24 Today I'll provide summary of our conclusions
25 from the midterm review of California's Advanced Clean Car

program.

--o0o--

AIR RESOURCES ENGINEER MADER: First, let me start off with a refresher on the Advanced Clean Car program. In 2012, the Board adopted a comprehensive set of regulations for light-duty vehicles as an integrated package laying out emissions standards through the 2025 model year. As shown in the pie chart, there are three distinct elements that make up the program. The first two are part of a Low Emissions Vehicle or LEV program. The LEV criteria program provides standards for pollutants such as hydrocarbons, oxides of nitrogen, and particulate matter. While the LEV greenhouse gas, or GHG, program provides standards for pollutants such as carbon dioxide and methane. As adopted, these two elements will yield a projected 75 percent reduction in criteria pollutants, a 90 percent reduction in the PM standard, and a 34 percent reduction in greenhouse gas emissions by 2025.

The third key element of the program is our zero-emissions vehicle, or ZEV, program. The ZEV mandate is a technology-forcing program that requires vehicle manufacturers to produce an increasing number of ZEVs including battery, fuel cell, and plug-in hybrid electric vehicles in a 2018 through 2025 model years.

--o0o--

1 AIR RESOURCES ENGINEER MADER: Even with the
2 significant climate change and air quality challenges. On
3 top of the timeline, we have identified the nearer-term
4 climate goals. Equally important, on the bottom we have
5 identified near-term air quality standards for particulate
6 matter, or PM, and ozone. The adopted LEV III program
7 represents our third generation of light-duty vehicle
8 standards. These fleet-wide emissions reductions are
9 needed in the light-duty transportation sector to help
10 attainment for both the 2023 and 2031 air quality
11 requirements as well as a 2020 and 2030 greenhouse gas
12 targets.
13 The ZEV requirement continues promoting the
14 development of advanced technology that is needed to put
15 us on the path to electrifying the fleet in order to meet
16 longer-term goals.
17 --o0o--
18 AIR RESOURCES ENGINEER MADER: With that
19 background, let's move into midterm review. When adopted
20 in 2012, the Board noted a number of specific areas that
21 they wanted staff to investigate and report back on as we
22 got closer to implementation. Taking these one by one:
23 With respect to greenhouse gas, the Board committed
24 staff to working with our federal agency partners to
25 reevaluate the appropriateness of the 2022 through 2025

1 model year greenhouse gas standards. This is the midterm
2 review we have been hearing so much about these days.
3 For criteria pollutant standards, there were a
4 couple of areas regarding the one milligram per mile PM
5 standard. Specifically, industry voiced concern at the
6 time regarding the accuracy of measurement equipment at
7 those very low levels and several Board members asked us
8 to track technology development to confirm that the
9 standards were both technically feasible and appropriate
10 to begin phasing in for the 2025 model year.
11 And for the ZEV Program, the Board asked staff to
12 track the progress of technology and industry to evaluate
13 if the approp -- adopted requirements out to 2025 remained
14 appropriate for both California and the nine Section 177
15 states that have also adopted our requirements.
16 Given the newness of the plug-in hybrid electric
17 vehicle, or PHEV, technology in 2012, the Board also asked
18 staff to study the development and usage of PHEVs to
19 reevaluate whether they were treated appropriately within
20 the regulation.
21 --o0o--
22 AIR RESOURCES ENGINEER MADER: Before we go
23 farther, I'd like to take a moment to help clarify some of
24 the interactions between our midterm review and a parallel
25 review that our federal partners, U.S. EPA and the

1 National Highway Traffic Safety Administration, or NHTSA.
2 Two of the elements in the advanced clean car
3 review, the criteria pollutant standards and the ZEV
4 Program, are California specific requirements and
5 therefore only part of ARB's midterm review.
6 However, both California and the federal program
7 review overlapped in the assessment of the greenhouse gas
8 standards. I'll elaborate in the next few slides how
9 U.S. EPA, NHTSA, and CARB collaboratively conducted an
10 assessment of the greenhouse gas standards as part of a
11 national program.
12 --o0o--
13 AIR RESOURCES ENGINEER MADER: Starting in 2012,
14 we adopted the Advanced Clean Cars program and later that
15 year the federal greenhouse gas standards were adopted.
16 As part of an agreement to promote a single national
17 program for greenhouse gas standards, California amended
18 its regulation in late 2012 to include a provision known
19 as "deemed to comply," allowing manufacturers to comply
20 with the national standards in lieu of the
21 California-specific standards. This agreement was
22 premised on strong national standards.
23 Over the last four years, extensive work has been
24 done by CARB, EPA, and NHTSA including internal and
25 external research, surveys and analysis of vehicle owners,

1 and laboratory testing to inform the review of the
2 national standards.
3 In July of last year, the first key milestone in
4 the federal review occurred with the release of the
5 Technical Assessment Report, or TAR, jointly authored by
6 CARB and its federal partners. Later that year, CARB
7 hosted a technical symposium that covered emerging
8 technologies not included in the TAR but being pursued by
9 vehicle manufacturers for near-term implementation.
10 Finally, this year we released our midterm review
11 report in preparation for today's hearing. A final
12 determination was also issued by the EPA earlier this year
13 that concluded EPA's national greenhouse gas standards for
14 2022 through 2025 model years were appropriate and would
15 remain as currently adopted.
16 However, just last week the new federal
17 administration announced that they will be reconsidering
18 that final determination over the course of the next year.
19 We do not believe that reconsideration is warranted given
20 the completeness of the review that has already occurred.
21 --o0o--
22 AIR RESOURCES ENGINEER MADER: Okay. Let's
23 quickly review our greenhouse gas standards.
24 ARB established the first vehicle greenhouse gas
25 standards in the nation beginning with the 2009 model

year. Subsequently, U.S. EPA also set standards for 2012 through 2016 that closely aligned with California's standards and paved the way for the first national program.

Then in the 2012 time frame, CARB and EPA separately set comparable greenhouse gas standards out to 2025 and again provided for a continuation of the national program. However, given the latter years of the standard were still 10 years away, CARB and the federal agencies agreed to conduct a midterm evaluation focused only on the reassessment of the appropriateness of the 2022 through 2025 standards.

--o0o--

AIR RESOURCES ENGINEER MADER: So what have we learned? First let's take a look at how manufacturers are complying with the current standards.

The yellow diamonds on the graph represent the greenhouse gas standards for the nationwide fleet for the last four years and, for reference, also show what the standards would be if they were specific to the California fleet. Since the California fleet of new vehicles sold each year includes a higher fraction of cars than the nationwide fleet, the standards for California is lower than for the federal fleet. And of course, you can see that the standards get progressively lower each year.

--o0o--

AIR RESOURCES ENGINEER MADER: If we now look at the bars on the chart, we can see what emission levels the actual fleet was certified to in each of the last four years. Vehicle manufacturers have been overcomplying with the federal standards for each of the last four years. For comparison, you can see that the California fleet, which includes a higher fraction of zero-emission vehicles, is generally overcomplying by an even larger margin. Also noteworthy is that this overcompliance generates credits for the vehicle manufacturers, which they can then bank and use in future years to help meet standards.

--o0o--

AIR RESOURCES ENGINEER MADER: So why are the vehicles able to overcomply? Because manufacturers and suppliers have been quite busy. Technology to reduce greenhouse gas emissions has been evolving rapidly and manufacturers have been able to roll out the new technology at a significant pace. Much of the gains observed so far are from improved engines and transmissions, like smaller turbocharged engines and redesigned multi-gear automatic transmissions.

However, there are several other key technologies that have been helping, including vehicle light-weighting,

1 improved aerodynamics, and lower rolling resistance tires.
2 Together, these reduce the amount of energy needed to move
3 the vehicle.
4 And other technologies are just now entering the
5 market in large shares like stop-start systems that
6 temporarily turn the engine off when a vehicle is at idle.
7 All told, over 20 percent of new vehicles sold in
8 2016 model year already meet the 2020 model year
9 standards - a full four to five years ahead of the curve.
10 --o0o--
11 AIR RESOURCES ENGINEER MADER: So what more is it
12 going to take to get out to 2025? Predominantly,
13 incremental improvements to conventional technologies.
14 The pie chart here shows the composition of the
15 projected vehicle fleet that would be needed in 2025 to
16 meet the standards. From the extensive testing and
17 modeling analysis for the midterm evaluation, gasoline
18 engines are predominant, with nearly 95 percent of the
19 fleet primarily utilizing advanced technology engines. Of
20 note, only a small portion of the fleet would need to be
21 electrified.
22 Regarding costs, the most recent analysis for
23 EPA's proposed determination shows that the cost to comply
24 is $300 lower than originally projected in 2012.
25 --o0o--

1 AIR RESOURCES ENGINEER MADER: So what does this
2 all mean in California?
3 Back in 2012, we projected the average fleet out
4 to 2025 model year, shown as the black line on the graph,
5 culminating in a value of 167 grams per mile in 2025.
6 Since that time, we have four additional years of data on
7 the exact mix of cars and trucks being sold. We have also
8 seen gasoline prices fall dramatically and shift in
9 consumer purchases away from car models and into small
10 SUVs. Taking all this into account, we have updated our
11 projections of the future fleet, including analyzing a few
12 different sensitivity cases regarding future fuel prices
13 and the types of vehicles being sold. The green-shaded
14 area represents what these new analyses project for
15 California and, as you can, even with the slight shift in
16 sales mix that is occurring, California is still on track
17 for the same or better greenhouse gas reductions by 2025.
18 --o0o--
19 AIR RESOURCES ENGINEER MADER: During the midterm
20 review, the vehicle manufacturers raised concerns with the
21 analysis and conclusions. Primarily the manufacturers
22 have indicated they believe that the analysis
23 overestimates the efficiency of some of the technologies
24 and thus underestimates the total amount of technology
25 that will be needed. The rationale continues that adding

more advanced technology, specifically strong electrification like full hybrids, will mean higher costs to comply than projected. And, they argue, consumer acceptance and demand for fuel efficient vehicles, especially strong electrification, is inadequate to enable them to meet the standards.

Staff, however, disagrees. The data underpinning our analysis is exhaustive and well grounded in testing of actual engines sand transmissions and supports that the standards can be met without the higher levels of technology industry is suggesting. Alternative scenarios show that there are several cost-competitive gasoline technologies available to meet the standards. These analyses do not even include some promising technologies that manufacturers have already announced for the near future. Lastly, electrified vehicle sales in California are already at levels near what the projected as needed by 2025 and prospective buyers have expressed interest in zero-emissions vehicles at even higher levels than that.

Which leads us to our recommendation for the greenhouse gas standards.

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AIR RESOURCES ENGINEER MADER: Based on the extensive analysis done with our federal partners over the last four years, the data supports the conclusion that the

1 2022 through 2025 model year federal standards are
2 appropriate as currently adopted. Accordingly, staff
3 recommends continued participation in a national program
4 through 2025, provided no further changes weaken the
5 expected benefits in California.
6 --o0o--
7 AIR RESOURCES ENGINEER MADER: Today's
8 presentation concludes California's midterm review of the
9 2022 through 2025 greenhouse gas standards. The U.S.
10 EPA's review has also been concluded, after an extensive
11 public process, and drew complementary conclusions
12 consistent with the data. U.S. EPA is reopening that
13 process. Staff believes the evidence and the law do not
14 support this action.
15 Should that federal process nonetheless continue,
16 CARB will continue to vigorously advocate for continuing
17 greenhouse gas reductions as the evidence indicates is
18 appropriate.
19 Should the federal standards not follow the best
20 available evidence, staff will have to revisit our
21 recommendation regarding the one national program in light
22 of any changes.
23 Also of note is that Canada is performing an
24 independent review of greenhouse gas standards that are
25 closely aligned with the currently adopted federal

standards. We are engaging in technical dialogue directly with Canada as their decision will have a significant bearing going forward.

Additionally, staff will continue to monitor global activities in this area.

--o0o--

AIR RESOURCES ENGINEER MADER: Before we leave our discussion of the greenhouse gas standards, I would like to point out that the shift from cars to small SUV sales does have a large impact nationally. Specifically, the national fleet was originally projected to be at 163 grams per mile by 2025 model year. But the updated analysis suggests it will be closer to 175 grams per mile due to the larger fraction of truck sales.

While staff's recommendation is to keep the greenhouse gas standards as currently adopted, a sensitivity analysis found it would add significant cost to recapture the original projected reductions on a national level.

This concludes the greenhouse gas portion of the midterm review.

--o0o--

AIR RESOURCES ENGINEER MADER: Now I'll move on to particulate matter, or PM, portion of the review.

Under the previous standards the PM limit was 10

1 milligrams per mile even though most gasoline vehicles
2 actually emitted below 1 milligram per mile. However,
3 some new technologies, most notably direct fuel injection
4 systems, were starting to show up with significantly
5 higher PM emissions.
6 To avoid backtracking, the LEV III standards
7 established both an interim PM standard at 3 milligrams
8 per mile and a final standard at 1 milligram per mile.
9 As shown by the bars on the graph, both standards
10 phase in over multiple years with vehicles beginning just
11 now to certify to the 3 milligram per mile standard, while
12 the 1 milligram per mile standard starts to take effect
13 with the 2025 model year.
14 In 2012, the Board directed staff to re-examine
15 the measurement methods to confirm they were able to
16 measure at the 1 milligram level.
17 And the Board also asked staff to re-examine the
18 stringency and phase-in timing of the 1 milligram per mile
19 standard.
20 --o0o--
21 AIR RESOURCES ENGINEER MADER: In responding to
22 the measurement question, staff conducted extensive
23 emissions testing and research of laboratory methods and
24 alternative measurement methods. The results of that
25 investigation, which included several peer-reviewed

1 publications, were presented to the Board in October 2015.
2 And while the investigation included a look at many
3 alternative methods such as particulate number counts and
4 cutting-edge real-time measurements, our conclusions were
5 that the current gravimetric method for measuring PM
6 emissions is sufficiently accurate and continues to be
7 appropriate for the future.
8 --o0o--
9 AIR RESOURCES ENGINEER MADER: Next was
10 evaluating the feasibility and implementation of the 2025
11 PM standards. Part of the original concern was that the
12 engine technologies needed for stringent greenhouse gas
13 emissions standards would have difficulty with PM
14 emissions control. Accordingly our testing focused on
15 recently redesigned vehicles with advanced greenhouse gas
16 control technologies similar to what is expected as
17 greenhouse gas standards decline.
18 The vehicles tested are shown across the bottom
19 of the chart and include vehicles with newer fuel
20 injection, hybrid, and plug-in hybrid electric vehicles.
21 While most of these vehicles are not yet
22 certifying to a 3 milligram per mile standard, you can see
23 from the chart that many are already emitting at a level
24 that is at half the standard.
25 However, when looking at the future 1 milligram

per mile standard, only a subset of the vehicles currently comply. Most vehicles will likely go through another engine redesign cycle to implement the further refinements needed to comply with the 2025 standard. So let's talk about the type of refinements that are needed.

--o0o--

AIR RESOURCES ENGINEER MADER: Good PM control requires tight control of air and fuel during all operational modes of the engine. The most important aspect is control within the combustion chamber itself. Our testing and research found that manufacturers and suppliers are rapidly learning in this area. But the process takes time to optimize and it must be done in conjunction with greenhouse-gas-related engine updates to ensure complete control for all emissions.

While we expect manufacturers will likely meet the PM standards with optimized designs and in-cylinder control, there are also after-treatment technologies that can be used to control PM emissions.

--o0o--

AIR RESOURCES ENGINEER MADER: Gasoline particulate filters, or GPFs, can be used to filter and continuously oxidize particles that are emitted from the engine. The photo on the side shows a prototype GPF tested by CARB on two higher emitting vehicles. The

1 results in the bar chart show PM emissions of over 5
2 milligrams per mile before installation, and levels below
3 1 milligram per mile with the system installed.
4 GPFs can effectively control PM, but they also
5 represent added hardware and expense. GPFs are not yet in
6 wide-scale production, but they are expected to be widely
7 used in Europe. From staff's analysis, GPF technology may
8 be best used for added flexibility to vehicle
9 manufacturers when they design for compliance.
10 --o0o--
11 AIR RESOURCES ENGINEER MADER: In our
12 investigation, we observed that the effectiveness of PM
13 control can vary during different types of driving. The
14 blue bars show the results from our testing for the
15 vehicles that already emit less than 1.5 milligrams per
16 mile on the standard emissions test cycle.
17 The yellow bars show results from the same
18 vehicles when driven on a more aggressive test cycle. As
19 you can see, most of these vehicles have similar emissions
20 results across the two cycles and are still below 1.5
21 milligrams per mile, indicating robust PM control.
22 However, there are some test results that show
23 significantly higher PM emissions under more aggressive
24 driving conditions.
25 --o0o--

1 AIR RESOURCES ENGINEER MADER: In conclusion,
2 staff has determined that the 1 milligram per mile PM
3 standard is feasible and therefore recommends no change to
4 the standard or the phase in said you'll.
5 However, CARB plans further study and may
6 consider future regulatory proposals to ensure good PM
7 control in all real-world driving conditions.
8 --o0o--
9 AIR RESOURCES ENGINEER MADER: For the third
10 piece of our review I would like to turn the presentation
11 over to my co-worker, Ms. Anna Wong, to summarize the
12 findings of our review of the zero-emissions vehicle
13 requirements.
14 --o0o--
15 STAFF AIR POLLUTION SPECIALIST WONG: Good
16 morning, Chair Nichols and members of the Board.
17 For the next section of the presentation, I will
18 focus on the zero-emission vehicle, or ZEV, regulation.
19 Prior to the Board adopting the Advanced Clean Cars
20 amendments in 2012, the ZEV regulation essentially
21 flat-lined the requirements past the 2018 model year. In
22 2012, the Board adopted annual increasing requirements
23 through 2025 model year that were projected at that time
24 to result in 15 percent of 2025 model year new car sales
25 in California to be ZEVs and plug-in hybrids. After this

historic increase in ZEV requirements, the Board asked staff to ensure those requirements would still be appropriate leading up to the 2018 model year implementation, both in California and the other states that have adopted California's regulations, often referred to as the Section 177 ZEV states.

Lastly, when the Advanced Clean Cars program was adopted, a new type of vehicle was emerging with the release of the Chevrolet Volt plug-in hybrid. Since plug-in hybrids were projected to play a significant role in most manufacturer's compliance through 2025, the Board wanted staff to review this new technology.

--o0o--

STAFF AIR POLLUTION SPECIALIST WONG: In 2011, as the staff report for the Advanced Clean Cars rulemaking was being released, just two models were available and accounted for less than 10,000 new sales. Through the end of calendar year 2016, nearly 300,000 ZEVs and plug-in hybrids have been registered in California and in the Section 177 ZEV states with nearly 30 different models on the market.

--o0o--

STAFF AIR POLLUTION SPECIALIST WONG: What has this meant for regulatory compliance? Shown in the blue shaded area on the screen is the total number of ZEV

1 credits required for the 2012 through 2017 time frame,
2 with the California requirements on the left and the
3 Section 177 ZEV states on the right.
4 The growth in new sales of plug-in hybrids and
5 ZEVs has resulted in an overproduction of regulatory
6 credits, making most manufacturers overcompliant with the
7 current ZEV requirements, shown by the dark blue line.
8 --o0o--
9 STAFF AIR POLLUTION SPECIALIST WONG: Now, let's
10 combine the California and Section 177 ZEV state
11 requirements and look toward the latter years of the
12 program.
13 While the auto manufacturers have been building a
14 healthy credit bank by delivering ZEVs and plug-in
15 hybrids, it's important to remember future requirements
16 will be even more stringent. The future credit
17 requirement is not just larger, but the previously
18 approved amendments also reduce the number of credits
19 earned for each vehicle produced. As an example, this
20 star here represents the credits earned for the total
21 number of ZEVs and plug-in hybrids sold in model year
22 2015. If manufactures sold the identical number and type
23 of vehicles in model year 2018, they would only earn about
24 one-third of the credits, the second star. So the same
25 volume of vehicles results in overcompliance in earlier

1 years and undercompliance in later years.
2 Let's take a minute to look at how these 2018
3 through 2025 requirements translate into the number of
4 vehicles we can expect from the regulation.
5 --o0o--
6 STAFF AIR POLLUTION SPECIALIST WONG: As
7 previously mentioned, In 2012 the project compliance
8 scenario for the new increased ZEV regulation was to
9 result in roughly 4 million ZEVs and plug-in hybrids
10 cumulatively by 2025 model year. Over the course of this
11 review, updated compliance scenarios reflect vehicle
12 technology advancements evident in the market, and
13 compliance with the regulation will now result in roughly
14 2 million vehicles cumulatively over the 2018 through 2025
15 time frame. For reference, this is about 8 percent of new
16 vehicle sales in 2025 model year. Staff also integrated
17 various regulatory flexibilities adopted by the Board, as
18 well as banked ZEV credits as shown on previous slides.
19 --o0o--
20 STAFF AIR POLLUTION SPECIALIST WONG: The
21 transformation of the light-duty fleet has begun, and a
22 growing number of manufacturers appear committed to
23 long-term electrification. Manufacturers are competing
24 with each other for PEV consumers by continually refining
25 the products they offer to suit consumer preferences.

1 Outside of California, ZEV markets are expanding in the
2 U.S. as well as globally, indicating that the industry is
3 gaining momentum.
4 --o0o--
5 STAFF AIR POLLUTION SPECIALIST WONG: This shift
6 has been enabled by technology costs continuing to come
7 down. Both fuel cell systems and battery costs have
8 fallen dramatically from to 2006 to 2015, with fuel cell
9 systems dropping nearly 60 percent and batteries over 70
10 percent. Costs for both technologies are expected to
11 continue to drop as volumes increase and the technology
12 improves. Staff anticipates that battery electric or fuel
13 cell technology will not reach cost parity with
14 conventional gasoline technology until sometime after
15 2025.
16 --o0o--
17 STAFF AIR POLLUTION SPECIALIST WONG: Falling
18 technology costs will facilitate an increasing vehicle
19 range in future models, which will help to sustain and
20 expand the ZEV market. Automakers acknowledge that
21 vehicle range can be a significant barrier to consumer
22 acceptance of these new vehicle technologies. As shown,
23 even among current plug-in electric vehicle drivers,
24 dissatisfaction with all-electric range declines as
25 vehicle range increases. Fortunately, trends in new ZEV

1 offerings are aligning with those consumer preferences.
2 --o0o--
3 STAFF AIR POLLUTION SPECIALIST WONG: This chart
4 shows the number of vehicle models offered in various
5 vehicle size and all-electric range combinations. In
6 model year 2011, the orange icon represents one plug-in
7 hybrid offered in the small car category with an
8 all-electric range of 30 to 40 miles. And the two blue
9 icons represent all-battery electric models, both with a
10 range of less than 100 miles.
11 In model year 2012 additional vehicles were
12 introduced, and the larger icon represents more
13 battery-electric vehicle models offered in the small car
14 category. While the market began in smaller vehicle
15 platforms where costs are lower, over time auto
16 manufacturers have continued to release new models. So
17 that today's market has expanded into more vehicle
18 segments with longer ranges.
19 Within the next five model years we expect over
20 70 models that will provide consumers with more choices
21 aligned with their purchase references. Larger battery
22 packs on vehicles also could help offset cold weather
23 losses and help expand choices in different markets
24 outside California.
25 These bars highlight the market share of new

1 vehicles sold within each of the vehicle classes. As you
2 can see, the small SUV and midsize car segments are the
3 two most popular classes, which are also where many of the
4 future new models are expected to be offered, many with
5 extended vehicle ranges beyond today's offerings. This
6 broadening of the ZEV technology across the most popular
7 platforms shows promise not only for California but also
8 for the Section 177 ZEV states.
9 --o0o--
10 STAFF AIR POLLUTION SPECIALIST WONG: Nine states
11 have adopted California's ZEV regulation. Sales of ZEVs
12 and plug-in hybrids in the Section 177 states still do lag
13 behind California's market. And the Board, anticipating
14 this jump in the requirement, adopted appropriate
15 flexibilities to help ease the regulatory burden.
16 In 2012, the Board extended the "travel"
17 provision for battery electric vehicles through 2017 model
18 year, a change which has in turn created healthy credit
19 banks for manufacturers heading into more stringent 2018
20 and subsequent model year requirements.
21 The Board also adopted an optional compliance
22 path as an important flexibility provision, which, if
23 taken, requires manufacturers to deliver battery electric
24 vehicles prior to 2018 model year in the Section 177
25 states. This optional compliance path also reduces

1 automaker requirements in the Section 177 states for
2 battery electric vehicles and plug-in hybrids through
3 2020; and allowed manufacturers to pool their credits
4 amongst the Section 177 states for BEVs and plug-in
5 hybrids to further reduce state-specific burdens.
6 --o0o--
7 STAFF AIR POLLUTION SPECIALIST WONG: In 2012,
8 the Board adopt policies that require intermediate volume
9 manufacturers, or IVMs, to begin electrifying their fleets
10 starting in 2018. These policies redefined many of the
11 midsized manufacturers as large volume manufacturers and
12 allowed the remaining IVMs to meet their 2018 through 2025
13 model year requirements exclusively with plug-in hybrids.
14 In addition to some flexibilities that were afforded to
15 the IVMs in 2012, the Board adopted additional
16 flexibilities in 2014, ensuring these manufacturers would
17 remain defined as this smaller category IVMs through 2025
18 model year and granted more time to comply with their ZEV
19 requirements.
20 Since the 2012 and 2014 rulemakings,
21 manufacturers confirmed various plans for full compliance
22 with the regulation as adopted and are pursuing both
23 plug-in hybrid and ZEV models, some recognizing it will be
24 almost impossible to meet their obligation exclusively
25 with plug-in hybrids. At the 2016 L.A. Auto Show, CEO of

1 Fuji Heavy Industries, which produces Subaru vehicles,
2 indicated these intentions towards electrification.
3 --o0o--
4 STAFF AIR POLLUTION SPECIALIST WONG: While staff
5 is recommending to maintain the current ZEV requirements
6 to provide regulatory stability, because important
7 provisions are sunsetting at the same -- in the same time
8 frame. In the greenhouse gas program, two provisions
9 intended to support ZEVs are also scheduled to expire by
10 2025. Additionally, carpool lane access for ZEVs, funding
11 for hydrogen infrastructure, and federal tax credits for
12 plug-in vehicles will likely all expire before cost parity
13 of ZEVs with conventional gasoline technology is expected.
14 Staff will continue to monitor market trends so we can
15 bring the Board appropriate recommendations to continued
16 to support ZEVs through regulatory and nonregulatory
17 actions.
18 --o0o--
19 STAFF AIR POLLUTION SPECIALIST WONG: In 2012,
20 the Board strengthened the ZEV regulation, nearly tripling
21 the requirement for pure ZEVs in 2025 model year, and
22 shifting to a simpler annual increase in requirements.
23 Since then, the regulation is accelerating development of
24 ZEV technology toward commercialization, demonstrated by
25 the clear growth in the ZEV market, and over 70 unique ZEV

1 and plug-in hybrid models expected in the next five model
2 years.
3 Despite these successes, it is widely recognized
4 that the ZEV and plug-in hybrid market is still in the
5 early stages of its development. Given the remaining and
6 still significant barriers regulatory stability of the
7 2018 through 2025 model year standards can help ensure a
8 continued path of increasing but achievable ZEV volumes.
9 Therefore, staff is recommending to maintain the current
10 ZEV requirements, as adopted in 2012, in California, the
11 Section 177 states, and for intermediate volume
12 manufacturers.
13 --o0o--
14 STAFF AIR POLLUTION SPECIALIST WONG: When the
15 strengthened ZEV regulation was adopted in 2012, it
16 included a new focus on plug-in hybrids. In fact, we
17 expect over two-thirds of the vehicles resulting from
18 compliance with the regulation to be plug-in hybrids.
19 Little was known at the time about how these
20 types of vehicles were being driven, and their actual
21 environmental benefits, because there were so few
22 available to consumers in 2012. When these amendments
23 were approved, the Board directed staff to study in-use
24 data for plug-in hybrids, such as how they're driven and
25 charged, in addition to criteria pollutant and GHG

emissions.

In the time since the Board direction, eight manufacturers have provided in-use data on 11 different plug-in models and over 90,000 unique vehicles. That in-use trip-level data represents over 20 million miles of use by those vehicles.

--o0o--

STAFF AIR POLLUTION SPECIALIST WONG: We calculated electric vehicle miles traveled, or eVMT. eVMT represents the vehicle's miles driven on electric power. The green bars show the annualized eVMT for each of the models, while the yellow hatched bars represent the portion of a plug-in hybrid's miles that are powered by its internal combustion engine. Focusing in on annualized eVMT, plug-in hybrids have less eVMT than battery electric vehicles. Now, when I overlay this red line, which shows how many credits each vehicle receives in the ZEV regulation, based on the vehicle's electric range, you can see that relationally the eVMT of the vehicles and the relative amount of credit lines up pretty well.

--o0o--

STAFF AIR POLLUTION SPECIALIST WONG: In order to analyze the criteria pollutants, emissions testing was done at a Haagen-Smit laboratory. The focus was on examining start emissions from so-called blended plug-in

1 hybrids - hybrids that are pure electric at low vehicle
2 speeds but blend a mix of gasoline engine and electric
3 power at higher speeds and accelerations. The first bars
4 on the graph indicate the start emissions from three
5 different plug-in hybrids during the normal emissions test
6 cycle, and all of them readily met our existing standards.
7 Next, staff drove one of the vehicles on-road to
8 determine the types of driving maneuvers that caused the
9 engines to first start and then recreated those events
10 back in the laboratory. Under these other types of
11 driving conditions, start emissions were found to be about
12 2 to 5 times higher. For future plug-in hybrids, further
13 refinements and vehicle design changes are needed to
14 minimize emissions in real-world driving conditions.
15 --o0o--
16 STAFF AIR POLLUTION SPECIALIST WONG: Emissions
17 will depend on how these vehicles are charged. By design,
18 plug-in hybrids are intended to be flexible, which means
19 it is up to their drivers to charge or not. While most
20 consumers are satisfied with their plug-in hybrids, an
21 analysis of trip data shows many drivers do charge
22 routinely. These two comments from current plug-in hybrid
23 drivers highlight how charging behavior can vary based on
24 purchase motivation, vehicles battery capacity,
25 infrastructure availability, and energy prices. How these

1 factors change in the future will matter for how we
2 determine the new GHG clean air benefits of plug-in
3 hybrids.
4 --o0o--
5 STAFF AIR POLLUTION SPECIALIST WONG:
6 Specifically, we examined various scenarios
7 across a broad range of eVMT assumptions and found GHG
8 emissions to be highly variable, increasing the light-duty
9 vehicle fleet's GHG contribution up to 60 percent with
10 high plug-in hybrid penetrations in the fleet. Although
11 not shown here, NOx emissions follow a similar trend.
12 This is due to the highly user-dependent nature of plug-in
13 hybrids. If, say, charging infrastructure is not
14 available for a plug-in hybrid user to maximize their
15 eVMT, the GHG benefit of their vehicle will decrease.
16 --o0o--
17 STAFF AIR POLLUTION SPECIALIST WONG: Therefore,
18 based on the analysis I described, staff has concluded
19 that the regulation as adopted in 2012 appropriately
20 credits plug-in hybrids and allows for manufacturers to
21 comply with this technology through 2025 model year, as
22 staff expects over two-thirds of vehicles to be plug-in
23 hybrids cumulative according to its latest compliance
24 scenarios.
25 Plug-in hybrids will still play a significant

1 role in transforming the light-duty sector, but at this
2 time, no additional regulatory credit is needed.
3 --o0o--
4 STAFF AIR POLLUTION SPECIALIST WONG: Let's take
5 a minute to review the comments we received since
6 releasing our midterm review report. One issue brought up
7 by dealers in the northeast and Oregon was a concern over
8 a provision removed during the 2012 amendments that gives
9 additional credits for vehicles that are "placed in
10 service."
11 In 2018 and beyond, battery electric vehicles
12 will earn credits upon delivery for sale, meaning when
13 dealers take delivery of the vehicles on to their lots.
14 Dealers are concerned that their lots will be inundated
15 with ZEVs and plug-in hybrids, and manufacturers will not
16 help support the sale of these vehicles. Thus plan staff
17 to monitor this issue and consider regulatory changes as
18 appropriate.
19 The Board also received comments from the auto
20 industry which were in line with those received during the
21 midterm review process, asking for more plug-in hybrids
22 allowed to meet their requirement, reduction in the
23 requirements for the Section 177 states, and greater
24 support for complementary policies.
25 --o0o--

1 STAFF AIR POLLUTION SPECIALIST WONG: During the
2 course of the review several stakeholders and Board
3 members asked staff to consider various options to the ZEV
4 requirements before the 2025 time frame. Here are three
5 options that could be investigated for the 2022 through
6 2025 model year.
7 One, increasing the stringency of the regulation
8 with a specific focus on pure ZEVs.
9 Two, would be to require a greater all-electric
10 functionality to qualify as a plug-in hybrid.
11 And, lastly, restrictions on the use of purchased
12 or banked ZEV credits such as having credits expire,
13 depreciate with time, or be restricted in what portion of
14 the annual obligation that could be satisfied with
15 credits.
16 However, full consideration of these options have
17 not been vetted through the process and are not
18 recommended for these years.
19 --o0o--
20 STAFF AIR POLLUTION SPECIALIST WONG: Our
21 recommendation to stay the course achieves a balance
22 because there are still significant barriers to increasing
23 ZEV sales. The 2016 California ZEV Action Plan summarizes
24 an extensive list of complementary policies. In addition,
25 some new measures are launching to address two of the more

1 significant barriers: A lack of consumer awareness and
2 insufficient public fueling infrastructure.
3 New and expansive consumer campaigns are
4 beginning to take shape in California and nationally.
5 This includes efforts by the PEV Collaborative and its
6 Veloz initiative, NESCAUM'S effort to select -- effort to
7 select markets nationally, and Volkswagen's investment in
8 campaigns as part of the diesel settlement's ZEV
9 Investment Plan that you will be hearing in the next item.
10 In the area of fueling infrastructure, the
11 passage of Senate Bill 350 in 2015 created a new
12 transportation electrification priority for electric
13 utilities, allowing them to make large investments in
14 charging infrastructure and other PEV services,
15 anticipated to be several billion dollars by 2030.
16 Additionally, CARB is reviewing the first Volkswagen ZEV
17 investment plan that proposes a large public charging
18 infrastructure network. Finally, for hydrogen
19 infrastructure the Energy Commission has proposed new
20 station grants that include major energy companies
21 reentering the hydrogen business.
22 Addressing all these challenges with
23 complementary policies are essential to ensuring market
24 success for these vehicles.
25 --o0o--

1 STAFF AIR POLLUTION SPECIALIST WONG: We will now
2 conclude with what we think should be our next steps.
3 Following this midterm review, we need to look at the road
4 ahead, carefully studying how the transportation sector is
5 changing, and consider what new policies and regulations
6 California needs in 2026 and beyond.
7 --o0o--
8 STAFF AIR POLLUTION SPECIALIST WONG: As we begin
9 the development of new regulations, we need to understand
10 the gap in projected emissions from our current programs
11 relative to the state's targets.
12 The graph on the left represents total NOx
13 emissions in the South Coast Air Basin where over 85
14 percent arise from transportation sectors today. The
15 emission levels to reach attainment for 2031 are clearly
16 shown on the bottom. And the graph on the right
17 represents statewide GHG emissions for on-road cars and
18 trucks. Current programs provide important reductions,
19 but the gap is sill significant when the SB 322030
20 requirements are taken into account, as well as the
21 Executive Order 2050 targets.
22 It is clear, additional light-duty vehicle
23 programs will be needed to provide further reductions in
24 both criteria and greenhouse gas emissions.
25 --o0o--

1 STAFF AIR POLLUTION SPECIALIST WONG: To assess
2 how to fill this gap, the Mobile Source Strategy describes
3 updated scenarios showing actions that can help the state
4 meet our emissions targets.
5 This graphic shows a potential technology rollout
6 for the light-duty vehicle fleet that would put us on a
7 path to achieving the greenhouse gas, air quality, and
8 petroleum reduction goals. In this scenario, electric
9 vehicles move well beyond the current ZEV regulation,
10 scaling up to 100 percent of all new vehicle sales by
11 2050, with 4.3 million ZEVs and plug-in hybrids on the
12 road by 2030. Though this scenario is only a top-down
13 analysis, it does show that there needs to be a
14 significant shift towards electrification to ensure
15 California's long-term goals are being met.
16 --o0o--
17 STAFF AIR POLLUTION SPECIALIST WONG: In addition
18 to our own analysis and research, staff will carefully
19 evaluate relevant external research and maintaining
20 continued dialogue with stakeholders to help guide the
21 2026 and beyond policy questions. Several recent studies
22 have been released that we are beginning to review, but
23 there will be many more. Although staff have not endorsed
24 or critiqued any of these studies at this point, they are
25 shown here to emphasize how ARB relies on science, data,

1 and stakeholder perspectives in developing our
2 regulations.
3 For example, the American Lung Association study
4 focused on monetizing the public health and climate
5 benefits from a large transformation to electric vehicles
6 in California and the Section 177 states.
7 The Environmental Defense Fund and International
8 Council on Clean Transportation studies both conducted
9 technology and cost feasibility analyses of achieving more
10 greenhouse gas and fuel reduction benefits by 2030. And
11 the Indiana University study conducted a macroeconomic
12 analysis of vehicle standards showing potential positive
13 GDP and job impacts.
14 --o0o--
15 STAFF AIR POLLUTION SPECIALIST WONG: To move
16 forward and achieve the large emissions reductions that
17 are needed from the transportation sector in 2026 and
18 beyond, we must think outside the box in developing new
19 regulations. This slide rep -- this slide presents
20 examples of the kinds of issues we will consider.
21 For example, in the early years of the new
22 program, should fuels be addressed differently in the
23 regulation? The existing ARB GHG fleet regulation
24 includes an upstream emissions factor for ZEVs. Should
25 this be continued? Separately, is it appropriate to grant

1 ZEV regulation credits for automaker investments in
2 fueling infrastructure?
3 More broadly, a core question involves the
4 structure of the varying regulations within the Advanced
5 Clean Cars program. Specifically, how should the ZEV
6 regulation change as the fleet emission standards become
7 increasingly more stringent to inherently encourage
8 advanced technology?
9 Additionally, should the vehicle regulations
10 address the changing transportation sector to include car
11 sharing, ride hailing, and connected-autonomous vehicles?
12 If so, what is the role of the regulation in combination
13 with these other policies?
14 Finally, in the process for 2026, we believe we
15 can best consider these concerns that the industry and
16 others have highlighted in the context of reopening of the
17 federal midterm review. It's just a question of where to
18 spend our time and resources.
19 --o0o--
20 STAFF AIR POLLUTION SPECIALIST WONG: Although we
21 obviously have not determined the exact path we can bring
22 to you for the regulations beyond to 2025, there are some
23 guiding principles that we hope to follow as we prepare a
24 regulatory proposal over the next few years. We need to
25 seek a structure that maximizes the emissions reductions

long term but in a cost-effective way, and that encourages innovation by automakers and suppliers. We need to utilize technology forcing requirements but only where needed to address electric vehicle markets and investment barriers. We need to learn from innovative policies being implemented in Europe, Asia, and elsewhere. And we need to follow -- we need to carefully consider a transition from the end of the current program into the new program.

We will need to develop new regulations and partnerships with the Section 177 states, NESCAUM, the U.S. EPA, Canada, and others.

--o0o--

STAFF AIR POLLUTION SPECIALIST WONG: This concludes our California midterm review. And with that, staff asks the Board to concur with the recommendations presented today and described in the proposed resolution.

The recommendations are:

One, the adopted 2022 through 2025 GHG standards are appropriate and we recommend no change.

Two, the adopted one milligram per mile PM standard is feasible but new limits may be needed to ensure low emissions in use.

And, three, the current ZEV requirements can be met by the manufacturers and are appropriate to help further market development. Staying the course balances

1 significant process -- progress and remaining barriers.
2 Fourth, the last recommendation requests the
3 Board's concurrence that we begin the process of
4 developing new standards for 2026 model year and beyond
5 and to bring those standards to the Board for
6 consideration as soon as appropriate but no later than the
7 2020 model year.
8 This concludes my presentation.
9 CHAIR NICHOLS: Thank you. We're also joined
10 today by representatives from several of the states that
11 follow California's Advanced Clean Cars Program and that
12 have adopted our program. So I would like to call them
13 forward at this time.
14 We have three, starting with Rob Klee from
15 Connecticut's Department of Energy and Environmental
16 Protection.
17 Commissioner.
18 MR. KLEE: Thank you so much, Chair Nichols and
19 members of the Board. I believe that we're loading up our
20 slide show.
21 (Thereupon an overhead presentation was
22 Presented as follows.)
23 MR. KLEE: Thank you so much for the opportunity
24 to be here this morning.
25 And we can go to the next slide, I think.

--o0o--

MR. KLEE: Connecticut is proud to be among the states that have been implementing the Advanced Clean Cars Program, and I'm pleased to be here with my Section 177 colleagues in strong support of the staff's recommendations.

Connecticut is a long-time leader on climate change. We've been developing and supporting forward-thinking climate-related policies and legislation since the early 2000s. We've been participating in groundbreaking regional initiatives like the Regional Greenhouse Gas initiative, or RGGI, because we know that addressing climate change in a meaningful way presents Connecticut residences and our businesses with the opportunity to create a healthy and sustainable environment, a robust economy, and a high quality of life for current and future generations. Therefore we are forging ahead in all areas to meet our aggressive greenhouse gas reduction goals. But transportation accounts for 37 percent of greenhouse gases in Connecticut and 43 percent across new England. Without the ZEV requirements, we simply would not be able to hit our targets for this sector.

Next slide please.

--o0o--

1 MR. KLEE: The Northeast states have long been
2 leaders in environmental protection, even as our economies
3 have grown over the years. Whether ranked by emissions
4 per capita, total share of CO2 reduced since 1990,
5 statewide efficiency or other measures, it's not a
6 coincidence that the states have opted into this program
7 under Section 177 consistently rank among the very best
8 performers in the nation.
9 This chart as one example shows CO2 emissions per
10 unit of economic output for every state in the U.S., with
11 ZEV Program states highlighted in green. And note that
12 the folks here today did a little better than California.
13 (Laughter.)
14 MR. KLEE: Next slide please.
15 --o0o--
16 MR. KLEE: All of our MOU states have long-term
17 2050 goals that match California's. Many, including
18 Connecticut, are in the process of identifying or refining
19 interim targets as well. We're doing so at the direction
20 of my governor, Governor Dannel P. Malloy, who through the
21 Governors' Council on Climate Change, which I chair and is
22 made up of key state agencies, businesses, academic
23 institutions, and nonprofits, and we've been tasked with
24 setting targets for 2030 and 2040. Next slide.
25 MR. KLEE: Many of our governors signed an MOU in

2013 that -- there are eight states. They are California, Connecticut, Massachusetts, Maryland, New York, Oregon, Rhode Island, and Vermont. These governors set a collective target of having 3.3 million ZEVs on our roads by 2025. They further committed to establish a multi-state zero emission vehicle task force to develop and implement a comprehensive ZEV Action Plan designed to achieve our states' electrification goals.

The task force released this multi-state ZEV Action Plan in May of 2014 that identifies both the collaborative actions and individual state actions needed to address the full range of barriers to widespread adoption of electric vehicles, such as incentives, infrastructure development, fleets, workplace charging, and consumer education and outreach.

Next slide.

--o0o--

MR. KLEE: At the time our governor signed the eight-state MOU, this matrix that I'm showing you today would have looked much different. Nearly all of the policies shown here have been put in place in the past few years in anticipation of the 2018 ZEV requirements. Please note especially the top two lines.

Since the MOU our states have been meeting regularly with Air Resources Board staff and all the

1 automakers in a process we've been calling the New
2 Collaboration for ZEV Success. Early on in those
3 conversations, the automakers identified consumer
4 incentives and infrastructure as the two most important
5 policies to support near-term ZEV deployments. As this
6 chart shows, our states have stepped up and we are ready.
7 And, lastly, I'd like to announce one correction
8 to this chart. That asterisk under New York for consumer
9 vehicle incentives, you can change that to a check mark
10 because Governor Cuomo announced just this past Tuesday a
11 $70 million ZEV incentive rebate program that's up to
12 $2,000 per vehicle in New York.
13 Next slide.
14 --o0o--
15 MR. KLEE: And this is my last one. Just to say,
16 some of the recent highlights that we've been doing in
17 Connecticut to support ZEV's deployment.
18 We've added $3.7 million for funding for our
19 rebate in Connecticut called the Cheaper Program.
20 We've recognized this year and in past years our
21 EVs of the year, and the Chevy Volt was the winner in
22 2016.
23 We also honor our dealerships for their efforts
24 to deploy ZEVs. Stevens Ford in Milford was our winner
25 this year.

1 We provide grants for up to a hundred percent for
2 public charging stations and incentives for others to
3 deploy at workplace chargers. And we've ended range
4 anxiety in Connecticut. You're no further than 20 minutes
5 or 20 miles from a charge anywhere in the state of
6 Connecticut.
7 We have -- our Governor's Council on Climate
8 Change is focused with a laser focus on transportation,
9 looking at vehicle miles traveled. ZEV implementation
10 transit systems at high mileage users. Our comprehensive
11 energy strategy again highlights transportation and is
12 exploring the role the utilities play, taking some
13 learning from the things that have been going on here in
14 California.
15 So with that I'd like to pass the podium to my
16 neighbor to the north, Christine Kirby from Massachusetts.
17 CHAIR NICHOLS: Oh, thanks. We'll hold our
18 questions then till the three of your have all finished
19 your presentations.
20 BOARD MEMBER SHERRIFFS: But just in -- one of
21 the things that you said. It's a goal or everybody is
22 within 20 minutes of a charging station?
23 MR. KLEE: Currently everyone is within 20
24 minutes from a charging station in Connecticut.
25 BOARD MEMBER SHERRIFFS: Congratulations.

1 MR. KLEE: We've deployed that many stations.
2 We're a small state.
3 (Laughter.)
4 BOARD MEMBER SHERRIFFS: Don't apologize. Don't
5 apologize.
6 (Laughter.)
7 BOARD MEMBER SHERRIFFS: Well done.
8 MR. KLEE: Thank you.
9 Christine Kirby is next.
10 CHAIR NICHOLS: I assume you mean a level 2 or
11 higher, not just a plot, right?
12 Okay.
13 MS. KIRBY: Good morning, Chair Nichols and
14 members of the Board. I'm happy to be here, and thank you
15 for the opportunity.
16 Massachusetts is, like Connecticut, happy to be
17 among the states that have implemented the Advanced Clean
18 Cars program. And I'm pleased to be here with both New
19 York and Connecticut in strong support of the staff's
20 recommendations.
21 You heard from Commissioner Klee on the 177 state
22 greenhouse gas reduction goals. And in Massachusetts we
23 updated our clean energy and climate plan at the end of
24 2015. And we will be finalizing new rules in August in
25 response to Governor Baker's executive order on climate

1 change to ensure our 2020 goal is met.
2 Without the California program, we will not
3 achieve our near- or long-term goals; and those are our
4 greenhouse gas reduction goals.
5 The rest of my presentation will be focused on
6 the ZEV requirements.
7 Next slide please.
8 --o0o--
9 MS. KIRBY: A key theme you will here today is
10 whether the 177 states are ready for ZEVs in doing our
11 part. The answer is unequivocally yes. There is good
12 news in our states, as shown by this chart. Sales are up.
13 In December of 2016, Massachusetts saw the highest number
14 of rebates under our rebate program than any other month
15 since the program started in 2014. That's good news.
16 And the 177 states in 2016 saw an increase of 60
17 percent in total PEV registrations, which represents a 50
18 percent increase in market share in the Northeast.
19 Along with this, there are expanded numbers of
20 new models, including three models with all-wheel drive
21 capability. And that's something that we've heard
22 continually in the northeast, about the need to have
23 all-wheel drive vehicles. This also helped our sales.
24 Next slide please.
25 --o0o--

1 MS. KIRBY: More good news. Our states continue
2 to add charging stations in anticipation of a major
3 increase in vehicles beginning in the 2018 model year when
4 "travel" goes away. As many of you know, "travel" has
5 been in place, and we are anticipating that going away in
6 2018.
7 This chart shows that infrastructure is much
8 farther along in our states than it was in California,
9 when California ZEV requirements took effect in California
10 in 2012. Of interest is why we have -- still have fewer
11 stations in terms of absolute numbers. We actually have
12 doubled the capacity relative to the number of PEVs
13 currently on the road in our states. So one outlook for
14 every 10 PEVs compared to one outlook for 20 in
15 California.
16 Next slide please.
17 --o0o--
18 MS. KIRBY: Now, for the not-so-good news.
19 Because of the travel provision, manufacturers have faced
20 no binding sales requirements in our states -- in the
21 Northeast states; and it's not surprising that they have
22 not made meaningful effort to promote their vehicles in
23 our region. Or in many cases to even make them available
24 for a test drive.
25 Of five of the six OEMs, here's some examples:

1 The GM Spark EV, not for sale in the Northeast.
2 The Toyota RAV4, not for sale in the Northeast.
3 The Fiat Chrysler 500E, not for sale in the
4 Northeast.
5 Honda Fit EV. It's been for sale but the total
6 volume is capped. And one particular piece of
7 information: Only three rebates have been issued under
8 the Massachusetts rebate program in Massachusetts, simply
9 because the vehicle is not available, and it's not because
10 of a lack of interest.
11 And finally the Ford Focus. It is available, but
12 not in the numbers that we'd like to see.
13 Next slide please.
14 --o0o--
15 MS. KIRBY: Continue in this theme. We have been
16 pleased to see that many new battery electric products are
17 being introduced into the market. But, again, many have
18 been and remain practically unavailable, and there's three
19 examples of that here too.
20 Next slide please.
21 --o0o--
22 MS. KIRBY: We've presented this type of data in
23 the past. This is also on the issue of vehicle
24 availability. And we shared this at one of the past board
25 hearings. This snapshot was taken just two weeks ago and

1 compares vehicle availability in Sacramento and in Boston.
2 And the picture tells the story. You'll see much more
3 vehicle available in California than we do in Boston.
4 So given this reality, it's hardly surprising
5 that PEVs are selling more rapidly in California than in
6 our states.
7 Next slide please.
8 --o0o--
9 MS. KIRBY: We have identified consumer
10 awareness, as Anna has mentioned, as an issue. And we
11 note that vehicle marketing is critical in our states.
12 Looking at a measure of marketing effort, this slide shows
13 advertising dollars spent in 2015 with a Chevy Volt and a
14 Nissan Leaf. While both GM and Nissan both ran some ads
15 nationally, they chose to spend heavily on advertising
16 targeted for California consumers.
17 So comparing this investment in California to the
18 total lack of similar investment in the Northeast, it's
19 not surprising at all to see the discrepancy in numbers
20 from California and in the 177 states.
21 Next slide please.
22 --o0o--
23 MS. KIRBY: Moving onto the staff
24 recommendations. As I mentioned earlier, the 177 partner
25 states support the staff recommendations on the ZEV

1 requirements and the other parts of the Advanced Clean
2 Cars program. And I would like to make the following
3 seven points.
4 Number 1, banked credits mean industry can comply
5 through 2021 with no increase in market share. So that is
6 very important.
7 Number 2, scheduling a review too soon
8 perpetuates the incentive to fail. We need to make more
9 time to make the program work, particularly in the 177
10 states given "travel."
11 Number 3, technology is proven and costs continue
12 to fall.
13 And 4, most OEMs have not yet tried to build the
14 ZEV markets in the Northeast or in California to the
15 extent that's necessary.
16 Number 5, we need to focus on 2026 and beyond to
17 achieve the long-term greenhouse gas reductions. And
18 electrification of the transportation sector is essential.
19 We know this in Massachusetts and we know you know that
20 here as well.
21 A couple of comments on the midterm review. This
22 occurred five years after the initial 2012 commercial
23 volumes in California took effect. We need five years in
24 the Northeast as well. So we do not need another midterm
25 review until at least 2023. We need to build the market

1 post the travel provision going away.
2 Next slide please.
3 --o0o--
4 MS. KIRBY: Similar to Connecticut, I'd like to
5 provide some highlights of what's going on in
6 Massachusetts. The first is we enacted a piece of
7 legislation at the end of 2016.
8 Couple of highlights: The utilities can now
9 submit proposals for cost recovery of EVSE in
10 Massachusetts. And two utilities have done that. They've
11 filed with our Department of Public Utilities, which is
12 great news.
13 And building codes can include requirements for
14 EVSE, which is now under discussion in Massachusetts.
15 In 2016, we added $12 million to our EV rebate
16 program. This program is called the Massachusetts Offers
17 Rebates for Electric Vehicles, or MOR EV. This program
18 began in 2014. We've had great success with it.
19 We also implement two additional incentive
20 programs under the banner MassEVIP. The first is to
21 public entities, both the state fleet and municipalities.
22 So far we have funded 208 vehicles and 69 charging
23 stations under that program.
24 Also, we have a separate piece of MassEVIP where
25 we fund workplace charging. We've identified that as an

1 important piece to provide consumers with certainty that
2 they can charge. So far we've funded 388 units and 618
3 charging ports in Massachusetts. It's a very, very
4 popular program.
5 And finally, we've been partnering with Plug In
6 America - I know they're here today - on the first
7 statewide Mass Drive Clean program. We've hosted a number
8 of EV ride and drive events. So that's been very
9 successful.
10 And we've shown that people that ride in an EV
11 are more likely to buy an electric vehicle after they get
12 into one of these vehicles. So that's been exciting.
13 So to conclude, on behalf of the Baker-Polito
14 Administration, thank you for the opportunity to be here
15 today, and we look forward to working with California on
16 these issues.
17 Thank you.
18 CHAIR NICHOLS: Thank you.
19 MS. KIRBY: And I will now turn it over to my
20 colleague from New York, Steve Flynn.
21 CHAIR NICHOLS: Good morning
22 MR. FLYNN: Good morning, Chair Nichols, Board.
23 Thanks for having us here today. Thanks for providing the
24 opportunity for us to speak.
25 I'm Steve Flynn. I'm the Director of the

1 Division of Air Resources at New York State's Department
2 of Environmental Conservation. I'm also a somewhat
3 familiar face, appearing here over the history of time.
4 Commission Klee stole some of my thunder. Yes,
5 indeed, we just this week announced in New York a $70
6 million incentive program for electric vehicles. It's a
7 point-of-sale rebate program. So it reduces the
8 out-of-pocket expense for the buyers at the time.
9 It also includes a significant effort towards
10 additional outreach, so that we have an educated consumer
11 base. That follows closely on the heals just a couple
12 weeks ago of announcements for an additional 450 workplace
13 and public charging stations around the state.
14 And another important point I wanted to make is
15 relative to staff's presentation this morning on -- in
16 particular New York dealers have expressed concerns about
17 the distribution of credits and the timing of credits.
18 And we appreciate staff's recommendation to take a hard
19 look at this and to monitor this over time to see if there
20 is a problem. And we will most certainly be working with
21 staff on that and helping to understand the issue and
22 making recommendations if necessary.
23 Can I have the next slide please.
24 --o0o--
25 MR. FLYNN: Sometimes going forward requires us

1 to look backwards. And we have indeed come a long way
2 together. And the emphasis here is on "together."
3 California and the Section 177 states over time has -- the
4 program has been a partnership. Certainly California has
5 the leadership authority under Section 209 of the Clean
6 Air Act. Properly so. The issues here in California
7 predate federal efforts and have been severe, and
8 California is staffed and capable and equipped to address
9 those issues, as we've seen time and again with the work
10 of staff, as we saw at the beginning of today's -- with
11 the presentation to staff for their excellent efforts on
12 the Volkswagen case.
13 Section 177 allows other states to adopt the
14 program provided certain tests are met. We've done so.
15 And we have done so from the beginning. Mass and New York
16 were at the very beginning. We've been shoulder to
17 shoulder with California all along the way. It's not
18 always in full agreement, but nonetheless working closely.
19 We work closely with staff as these programs are developed
20 as staff -- we come to the Board to speak to you, to tell
21 you what we think and how these things affect us.
22 We also support you in Washington. When things
23 like waivers are up, we weigh in on those waivers.
24 We also support you in court. The Mass versus
25 EPA greenhouse gas decision certainly was a foundational.

1 The Green Mountain Chrysler-Plymouth case in Vermont on
2 the first round of greenhouse gas standards was pivotal.
3 And so we're here. We're with you. We believe
4 in what we're doing. We believe in what you're doing.
5 But some of that is also the flexibility that is necessary
6 going forward. Staff spoke of the optional compliance
7 plan and the travel provisions. We understand that. We
8 understand that this technological development sometimes
9 needs to germinate and mature in one place before it can
10 spread widely. We've supported those provisions. We
11 helped develop the optional compliance plans through
12 negotiations with staff and manufacturers.
13 California clearly has the lead, but the Section
14 177 states bring along market breadth and understanding to
15 really stabilize the results and improve the overall
16 results of what it is you're trying to do.
17 Can I have the next slide please.
18 --o0o--
19 MR. FLYNN: Why? Well, talking about greenhouse
20 gases. 177 states are all pretty much coastal, just like
21 California is. And certainly sea level rise is a highly
22 visible and very problematic issue associated with climate
23 change. My office is in Albany. I'm 140 miles from the
24 Statue of liberty, and yet I can watch the tide in the
25 Hudson River estuary out of my window. It's a big

1 problem. It's not just skirting the edges, and it's
2 pervasive.
3 Motor vehicles are the biggest part of our
4 greenhouse gas inventory in the Northeast. In fact,
5 they're also the greatest part of our criteria pollutant
6 inventory.
7 VMT continues to grow. We are controlling
8 stationary sources. We have cap-and-trade programs for
9 power plants for greenhouse gases. We're investing those
10 proceeds into energy efficiency.
11 We're doing what we can where we can. We need
12 the cars too.
13 But it isn't just greenhouse gases. We're also
14 nonattainment in metro New York area for ozone. Just like
15 with greenhouse gases, the motor vehicle sector is our
16 largest single sector. We can't get to attainment. We
17 can't get to the public health we're looking for without
18 the controls. So the California program is important as
19 part of our SIP as well.
20 Next slide please.
21 --o0o--
22 MR. FLYNN: But a key piece of this is that it's
23 working. From the beginning, the program -- very
24 beginning -- it has been identified as technology forcing.
25 And it has been. You know, the original standards when

1 someone put a LEV standard up on the board, everyone
2 cringed and said, "How will we ever get there?" Well, we
3 have. But you have, we have, the manufacturers have; and
4 don't lose site of that.
5 There's been a great deal of development here
6 and -- you know, I look at this slide and I recall that
7 when the Toyota Prius came out -- generation 2 Prius came
8 out in 2004, Toyota lost money on every one they sold.
9 They never said how much. I can't blame them. But since
10 then it's evolved. They've learned. They've matured the
11 product. They've refined the product. They've found ways
12 to contain the cost. It is my belief that it is now a
13 profitable automobile. And more than that, it's a
14 flagship for them. The technology is advancing. The
15 program is working. There are 300-mile BEVs that are out
16 there now. We didn't -- just didn't have that recently.
17 And some of these technologies are expan -- some
18 of the advancements that have occurred because of these
19 vehicles have expanded into other markets. We talked
20 about the 48-volt start-stop. I don't think we'd have
21 been there without the technology forcing elements of this
22 program. Some of this stuff would have happened, to be
23 sure. But I don't think any of us believe it would have
24 happened in the time frame that we're looking at now. And
25 time is important.

1 Another key piece of the evolution of the program
2 though has also been the relationship between states and
3 the manufacturers. We're not adversarial. We meet
4 regularly, often, to talk about the issues for advancing
5 this technology, for getting the marketplace mature, for
6 improving the salability and usability of these products.
7 So that is just -- it is another part of the evolution.
8 For example, we've been meeting -- we meet multiple
9 times. And just in a couple weeks at the New York Auto
10 Show we have a couple of days of meetings scheduled with
11 177 states. I think California is coming, and
12 manufacturers, at a showcase event of theirs.
13 Next slide please.
14 --o0o--
15 MR. FLYNN: This is kind of demonstrative of it.
16 That in just a few years we've seen range drastically
17 expand, charging time greatly improved. Certainly a key
18 is to users that they are not spending a lot of time
19 charging. This is -- these are things that just are
20 continuing to evolve and continuing to develop. Charging
21 is being installed now at 150 kilowatts. We have
22 planning -- the charging is on the planning board for 300
23 kilowatts. I'm not quite sure how we're going to maintain
24 the heat and deal with that, but we'll figure it out.
25 And the marketplace is competing on these

1 parameters. They're not just doing it; they're competing
2 on it.
3 We're now at an inflection point. The inflection
4 point is, as Christine described, the end of travel and
5 the bringing forward of the requirement in the 177 states.
6 We support the staff's recommendation to proceed with the
7 program. Let us move a foot. Let us keep an eye on it
8 but move forward.
9 Certainly it's a significant obligation for
10 manufacturers. But - and this is an important "but" -
11 manufacturers, states, consumers, infrastructure providers
12 all need certainty, a little bit of certainty. And as
13 staff said, push it out there a few years before we get
14 back at work at it. And Christine said this too. Let's
15 leave it in place for a while. Give us all some
16 certainty. And I think that's what we're asking for the
17 Board.
18 So in closing - just a couple of comments -
19 again, we support -- we stand here today to support the
20 staff recommendation as it -- as California seeks to
21 reduce the environmental impact of motor vehicle
22 technology, and do so in a progressive but achievable
23 manner.
24 We're committed to continue to work with the
25 manufacturers to address the obstacles and to help educate

1 consumers. We will work with infrastructure providers and
2 other stakeholders to ensure that consumers can experience
3 a seamless transition to the cleanest technology out
4 there. And it's important, folks. Tomorrow's environment
5 is counting on what happens here today.
6 Thanks.
7 CHAIR NICHOLS: Thank you very much. Thanks to
8 the three of you for traveling out here and spending the
9 time with us. And I assume that you're going to be
10 available throughout this discussion. And if possible, it
11 would be helpful to have you also present during the
12 discussion on the Volkswagen ZEV investment plan; because
13 while we're dealing only with the California plan here
14 today, there is a national plan that they've prepared as
15 well. And it would be interesting to get your comments on
16 how you see that helping us all out.
17 So thank you.
18 We do have two other state representatives with
19 us who were not part of this presentation. One is our
20 neighbor from Oregon, Leah Feldon. And then we'll also
21 hear from NESCAUM, which represents a whole group of
22 states.
23 So let's start with Leah please.
24 Welcome.
25 MS. FELDON: Good morning, Chair Nichols and

1 members of the Board. My name is Leah Feldon, and I'm the
2 Deputy Director of the Oregon Department of Environmental
3 Quality.
4 Thank you for allowing me the opportunity to
5 comment to the Board today. I'm very pleased to be here.
6 And I do want to briefly acknowledge my staff with me here
7 today, Dave Nordberg. Dave is our transportation program
8 coordinator, or better known as our LEV-ZEV expert.
9 On behalf of the Oregon Department of
10 Environmental Quality, I want to commend auto
11 manufacturers for the strong progress they've made meeting
12 future greenhouse gas and zero-emission vehicle
13 requirements. Since the adoption of the 2012 ZEV and LEV
14 III rules, the auto industry has made significant strides
15 in reducing greenhouse gases from conventional light-duty
16 vehicles and dramatic advances in emission-free vehicles.
17 We also want to recognize the substantial effort
18 the California Air Resources Board devoted to this midterm
19 review. We admire the breadth of this study, and conclude
20 it is appropriate to retain the current requirements for
21 the 2022 to 2025 model year vehicles.
22 Zero-emission vehicles are essential to meeting
23 Oregon's long-term greenhouse gas emission targets for
24 2050. Relaxation of the LEV III or ZEV rules would reward
25 manufacturers who made the least effort to prepare for

1 future requirements and do a disservice to manufacturers
2 who made the greatest effort to develop and market
3 compelling low-emission products.
4 We agree with the ARB staff that the auto
5 industry's progress raises the question whether the
6 requirements for 2022 should be strengthened. We also
7 want to emphasize the critical importance of regulatory
8 certainty, and therefore we believe it is appropriate to
9 continue the existing requirements unchanged.
10 However, conventional vehicles with even lower
11 greenhouse gas emissions are necessary for a secure
12 future, as are much larger numbers of ZEVs. And as we
13 heard in presentations today, the technology costs to
14 produce said vehicles is going down. To meet the imminent
15 need to future reduce greenhouse gas emissions, we urge
16 you to continue your pioneering work by developing strong
17 new standards for the period following 2025.
18 Oregon thanks you for all of your work to date
19 and future work combating greenhouse gas emissions to
20 protect public health and our environment.
21 Thank you very much for your consideration.
22 CHAIR NICHOLS: Thank you. We also admire what
23 Oregon has done to promote the whole market for EVs
24 through your Drive Oregon program. And I don't know if
25 you were prepared to comment. But I saw something the

1 other day since I subscribe to your emails about a
2 transformation in the program. Do you want to say a word
3 or two about what you're up to there. Or if you don't
4 want to, you don't have to.
5 MS. FELDON: Chair Nichols, members of the Board.
6 I don't think we're prepared to talk about the Drive
7 Oregon program at this time.
8 CHAIR NICHOLS: All right. That's okay.
9 MS. FELDON: But I would be happy to get back
10 with you an some information.
11 CHAIR NICHOLS: Well, we'll talk later. Thank
12 you.
13 MS. FELDON: Thank you very much.
14 CHAIR NICHOLS: Thank you.
15 Matt Solomon from NESCAUM.
16 Welcome, Matt.
17 MR. SOLOMON: Thank you very much. Good morning,
18 Chair Nichols, members of the Board. Appreciate the
19 opportunity to be here. You've heard a lot from the 177
20 states, so I'm going to try to keep this brief.
21 I think we've shown our states have done
22 everything that they can do to prepare the market to get
23 ready for these cars. But we can't build the market on
24 our own. It is time for the automakers to step up. We
25 need them to come into the market, not just with product,

1 but with the earnest and energetic marketing effort that
2 they make with vehicles that they actually want to sell.
3 Thus far they have not made the effort to build ZEV
4 markets in the northeast because they haven't had to.
5 They haven't had to because of the "travel" provision.
6 Therefore we strongly agree with staff's recommendations
7 and we hope you will too.
8 Thanks very much.
9 CHAIR NICHOLS: Okay. Thanks.
10 Next we'll turn to Henry Hogo from the South
11 Coast AQMD.
12 Good morning, Mr. Hogo.
13 MR. HOGO: Good morning, Chairman Nichols and
14 members of the Board. I'm Henry Hogo, Assistant Deputy
15 Executive Officer at the South Coast Air Quality
16 Management District.
17 I'm pleased to be here today to provide the South
18 Coast District's staff support of the staff
19 recommendation. We strongly believe that these standards
20 should be maintained as determined by the midterm review
21 for the greenhouse gas standard. We certainly support the
22 1 milligram standard. In fact, at the 2016 AQMP that you
23 approved yesterday - and I want to thank you for that -
24 shows that light-duty vehicles actually are the largest
25 source of directly emitted PM in our basin from mobile

1 sources. It's the fourth highest contributor. So we
2 strongly support that. And we strongly support the
3 zero-emission technology.
4 Locally we're going to continue to encourage
5 deployment of zero-emission vehicles, especially through
6 the Enhanced Fleet Modernization Program. And we look
7 forward to working with you on the post 2026 model year
8 standards and looking to strengthen that moving toward
9 more zero-emission vehicles.
10 Thank you again for the opportunity to speak
11 today.
12 CHAIR NICHOLS: Thank you.
13 We really do have a who's who of everybody in the
14 ZEV world here today.
15 So move next to John Bozzella from the
16 Association of Global Automakers.
17 MR. BOZZELLA: Thank you, Chair Nichols, members
18 of the Board. I'm John Bozzella, President and CEO of
19 Global Automakers.
20 Our companies sell 56 percent of the cars and
21 trucks purchased here in California, most of which are
22 made in the U.S. We employ over 10,000 Californians at 79
23 facilities, including 18 R&D centers and three North
24 America headquarters.
25 You'd think given the heated rhetoric here in

1 California and in Washington over cars, there's much that
2 divides us. Not so. We agree that we need to continue to
3 reduce greenhouse gas emissions and improve fuel economy.
4 We agree that developing advanced technologies and
5 consumer acceptance and demand for those technologies are
6 central to the achievement of our goals. We agree we
7 should be making decisions using the latest science and
8 data. We also agree that we must work together. And
9 fundamentally we agree that there is a more effective and
10 efficient way forward than regulatory programs that are
11 inconsistent and require different compliance paths with
12 no added benefit to our consumers or the environment.
13 When EPA prematurely ended its part of the
14 midterm review, we lost an important part of the
15 discussion, perhaps the most important part: making sure
16 we ended up with a fully aligned national program that
17 balances innovation, compliance, and consumer needs and
18 wants. Last week's decision to reopen the midterm review
19 without prejudging the outcome is fully consistent with
20 the commitments ARB, EPA, NHTSA, and the industry agreed
21 to back in 2012.
22 I want to assure you that we are as committed to
23 the goals of one national program today as we were in
24 2012. Right now we should all be getting back to work on
25 this. And your role will continue to be important for the

1 2022 to '25 standards and beyond.
2 Let me turn briefly to the ZEV mandate.
3 The program does have problems. We all know
4 this. We need to understand the state of the market, not
5 just the state of the technology. Meeting the significant
6 numbers here in California will be a big challenge. But
7 here at least you understand the importance of investing
8 in infrastructure and incentives to encourage markets.
9 This is why in percentage terms we're selling six times as
10 many ZEVs in California as in the Northeast states, with
11 similar numbers of models available for sale.
12 Second, the programs now who focus on one
13 electric technology rather than the broad range of ZEV
14 technologies distract us from what really matters, getting
15 more ZEVs into the marketplace by increasing consumer
16 awareness and acceptance; and it likely leaves benefits to
17 the planet on the table.
18 We've invested billions in advanced technology
19 vehicles. We remain committed to developing sustainable
20 markets for them and we look forward to working with you
21 to accomplish this critical goal.
22 Thanks for your time. I hope we get an
23 opportunity to discuss this and answer any questions you
24 have.
25 CHAIR NICHOLS: Thank you.

1 MR. BOZZELLA: You're welcome.
2 CHAIR NICHOLS: Mr. Douglas, welcome.
3 MR. DOUGLAS: Good morning, Chair Nichols, Vice
4 Chair Berg and members of the Board. I'm Steve Douglas
5 with the Alliance of Automobile Manufacturers. It's a
6 real pleasure to be here.
7 I only have three minutes so I'll go ahead. And
8 if you go to the next slide. And actually I only want
9 three minutes.
10 (Thereupon an overhead presentation was
11 Presented as follows.)
12 MR. DOUGLAS: Of course there's been a lot of
13 media attention around the Trump Administration, the
14 Alliance, automakers, GHG, ZEV, midterm review, waivers.
15 So I thought it might be helpful if I just kind of laid
16 the groundwork and tell you what the Alliance position is
17 and where we're coming from.
18 First, we fully recognize that California has a
19 waiver for greenhouse gas and zero-emission vehicles and
20 low-emission vehicle programs. And we have not requested
21 or advocated for the Administration to overturn those
22 waivers. We haven't.
23 We have consistently supported the midterm review
24 on the original timeline as it was laid out and agreed to
25 in 2012. And we did ask the Administration to return to

1 this timeline. So last week -- last week's activity
2 simply brought us back to where we would have otherwise
3 been but for EPA's action at the end of the last year, at
4 the beginning of this year, which we believe was
5 premature.
6 So with that, I'd like to turn to ZEV, which is
7 actually more my specialty. If you could go to the next
8 slide.
9 --o0o--
10 MR. DOUGLAS: First I just want to point out that
11 18 through 25 regulations haven't even started jet. So
12 the manufacturers have made great progress in developing
13 30 -- almost 30 high quality zero-emission vehicles.
14 They're efficient. They're safe. They're reliable.
15 They're fun to drive. And California, for your part - and
16 we appreciate this - has been very good at creating a
17 comprehensive program of complementary measures. However,
18 I want to point out we are a long, long, long way from the
19 finish line. The ZEV market is not sustainable today.
20 The regulations are very aggressive in California. It
21 requires tripling of the sales. So sales have to triple
22 over the next few years. In the Section 177 states it's
23 five to ten times that amount. So it's a bigger hurdle.
24 And we do expect sales in the 177 states will increase
25 over the next few years. But we don't see any way that

1 they will reach the level that California's at in the time
2 that's required. So I think right -- automakers are
3 rightfully concerned about their ability to comply with
4 these regulations.
5 We've recommended revising the requirements now.
6 However, if not now, we'd ask the Board to continue to
7 monitor this - and staff - and make appropriate changes,
8 monitor the ZEV market and make appropriate changes in the
9 2019 time frame.
10 Thank you very much, and I'd be happy to answer
11 any questions.
12 CHAIR NICHOLS: I think rather than engaging at
13 this point, we should just go through the testimony, and
14 then we'll have some conversation. Thank you.
15 MR. DOUGLAS: Okay. Thanks.
16 CHAIR NICHOLS: Ms. Lilly -- Amy Lilly. Good
17 morning.
18 MS. LILLY: Good morning. My name is Amy Lilly
19 and I'm here representing Mercedes-Benz. Today I'd like
20 to talk about our robust investments in electric mobility
21 and fuel cell vehicles, our plans for marketing these
22 products, and our commitment to partnering with California
23 to ensure our EV customers' infrastructure needs are met.
24 Due to time restrictions, I have left a longer
25 version of my remarks in the record, and I'm going to be

1 doing some fast talking here.
2 Mercedes-Benz' goal is to become the undisputed
3 leader in EV sales in the premium segment by 2025, and we
4 will have over 10 electric models by that year. This is
5 an ambitious goal, but we have already begun to seriously
6 invest in the transition to a more heavily electrified
7 fleet.
8 By the end of 2019 we'll have six PHEVs on the
9 market and we will continue to offer BHEVs through 2025
10 and beyond because we believe advanced long-range
11 batteries offer customers a no-compromise solution.
12 Starting in model year 2018 a hundred percent of our
13 Smart vehicles will be EVs; and Mercedes-Benz will begin
14 to launch our EQ brand in 2019. EQ stands for electric
15 intelligence, and it's comprised of comprehensive electric
16 ecosystem of services, technologies, and innovations,
17 which will be fully scalable across all model.
18 Lastly, we'll introduce our GLC F-Cell later this
19 year at the Frankfurt Auto Show. Almost $11 billion of
20 our research budget have been dedicated to e-mobility, and
21 we have invested over $1 billion in our global battery
22 production. Investments continue to be made in
23 manufacturing capacity, hardware and designs; and, rest
24 assured, these investments will continue regardless of
25 what the discussions will be with the regulations.

1 But just offering compelling products will not be
2 enough. Mercedes-Benz fully supports what CARB stated in
3 Appendix B of the recommendations for the midterm review;
4 namely, that fleet transformation to near or pure ZEV also
5 requires consumers to demand and ultimately purchase these
6 products. We're simply not going to reach our joint goals
7 unless we can move beyond early adopters to the mainstream
8 consumers.
9 I'm here to dispel the perception that our
10 dealers are not serious about selling ZEV vehicles. And
11 we heard that mentioned by Christine Kirby a little bit
12 earlier. Mercedes-Benz U.S.A. has created a new
13 department specifically tasked with preparing our dealers
14 to sell ZEV vehicles by developing and executing new and
15 enhanced training programs, installing charging stations
16 at dealerships or sales and service needs, and embarking
17 on marketing efforts nationwide.
18 Turning to infrastructure. I think everyone is
19 in agreement that the number of stations is woefully
20 inadequate. Considering that all automakers have plans to
21 introduce a variety of models in all segments,
22 infrastructure must be exponential growth. To help
23 address the concern, we and other automakers are not only
24 building ZEV vehicles, but we're also investing in needed
25 infrastructure. For example, we recently invested in

1 Charge Point. Also, Mercedes-Benz has been actively
2 supporting the CPUC recommendations to mandate the ISO
3 15118 communications protocol to ensure ZEV, P -- excuse
4 me -- PEVs to infrastructure interoperability.
5 In closing, when our CEO, Dr. Dieter Zetsche,
6 announced our goal of becoming the EV sales market leader
7 within the premium segment by 2025 has signaled that
8 Mercedes-Benz is committed to deploying electrified
9 vehicles in the mainstream market. We plan to work
10 collaboratively with CARB and other stakeholders to
11 overcome our consumer acceptance in infrastructure
12 challenges. And, lastly, we're ready to start the
13 discussion about how best to encourage additional ZEV
14 deployment after 2025.
15 Thank you.
16 CHAIR NICHOLS: Thank you.
17 Mr. Lord.
18 MR. LORD: Good afternoon, Chair Nichols and
19 Board members. My name is Michael Lord, and I'm an
20 executive engineer for the Product Regulatory Affairs
21 Division at Toyota Motor North America.
22 First I'd like to talk a little bit about some of
23 Toyota's products. Our Prius Prime, which is our new and
24 significantly improved plug-in hybrid, is on the market
25 now. We believe the Prius Prime is the most fuel

efficient vehicle in the U.S. today with 133 mpge and an estimated 640-mile range.

The EV range is 25 miles, and we've made many improvements to maximize the driver's EV experience by practically eliminating engine starts during those 25 miles.

And starting at 27,100, before the $4500 federal tax credit, we think it's a great value.

So in addition to the Prius Prime, Toyota continues to lead the initial market for fuel cell vehicles with the Toyota Mirai, a ZEV with an estimated 312-mile range and a 3- to 5-minute refuel time.

And we'd like to thank Chairman Nichols and Professor Sperling for being Mirai pioneers. We trust you've had good experience with the vehicle.

However, you may have some issues so far with infrastructure -- your experience with infrastructure at this stage. And although we made some great progress in California on stations, we have room for improvement in the coverage, reliability, and speed of construction.

And my colleague, who's scheduled to speak next, I think he will be later in the day. I think he's stuck in Riverside traffic.

(Laughter.)

MR. LORD: We'll speak about that later.

1 (Laughter.)
2 MR. LORD: So regarding improving in the ZEV
3 Program, I wish to make --
4 CHAIR NICHOLS: You should have been here for the
5 VMT discussion yesterday.
6 (Laughter.)
7 MR. LORD: Right. Thank you.
8 Regarding improvements to the ZEV Program, I wish
9 to mention four broad and core requests today.
10 First, we believe the role of plug-in hybrids is
11 undervalued in the current regulation. We still believe
12 that PHEVs can fulfill a significant portion of the
13 emission reduction goals from 2030 to 2050, and that the
14 staff's assessment of the emission impacts needs further
15 evaluation. PHEVs are a technology that customers can
16 embrace, and we believe the credit structure and the
17 current cap should be adjusted in the regulation.
18 Second, we believe while progress is made in the
19 Section 177 states, it continues to lag the California
20 market. Our request is not to make changes today, but I
21 ask you to direct staff to come back to you with a more
22 robust assessment of the Section 177 state markets and
23 potential regulatory flexibilities to address it.
24 Third, we believe CARB should consider increasing
25 the maximum credits for PHEV, BEVs, and fuel cells. PHEV

1 credits are max'd out at 80-mile range, and BEVs and fuel
2 cells are 350. By raising this cap, we think it's a good
3 tool incentivizing longer range vehicles in all three
4 categories.
5 And fourth, and in closing, we need to look at
6 ways to further accelerate hydrogen infrastructure
7 development. In addition to improving the existing AB8
8 process with the Energy Commission, we encourage ARB to
9 consider additional funding and incentives, including
10 credits under the ARB existing programs, to help us move
11 beyond the hundred stations. And we would like to ask you
12 to direct staff to come back to you with recommendations
13 on how to accelerate the build-out of hydrogen
14 infrastructure.
15 Thank you.
16 CHAIR NICHOLS: Thank you. So your colleague is
17 not here. We'll proceed next to NRDC.
18 Simon Mui.
19 MR. MUI: Good morning, Chairwoman Nichols and
20 members of the Board. Thank you. I'm Simon Mui with
21 NRDC, director of our vehicles and fuels program here on
22 the West Coast.
23 First I want to thank staff for their years of
24 hard work on this review. It's been carefully done,
25 thoroughly analyzed. And I think you can all breathe a

1 breath of relief today. Your staff has provided
2 substantial evidence, substantial evidence that the
3 existing standards can be met on time, with no
4 technologies, and a cost lower than we originally
5 anticipated in 2012. In a nutshell, the program is
6 working.
7 Both the Legislature and the Governor have spoken
8 loudly and clearly last year in setting aggressive carbon
9 reduction goals for 2030, aggressive electrification goals
10 through SB 350, and calling for us as a state to really
11 double down on meeting our air quality requirements.
12 These standards we're talking about today are the
13 state's major tool to do that. It's achieving the most
14 carbon reductions to date under AB 32 and nationally
15 through the national program. It's the main policy driver
16 for electrification and helping to improve public health
17 in a state where 8 out of 10 people still are breathing
18 unhealthy air.
19 For these reasons, we're asking the Board to
20 green light staff's proposal. Let's maintain the steady
21 course that California has been on, and continue that
22 through 2025, and begin the stakeholder process and
23 discussions around the next steps post 2025, and further
24 improve and strengthen the ZEV standard through that
25 process.

1 All eyes are looking to us today, particularly
2 given last week's disappointing announcement from the
3 Trump Administration to reopen the review process
4 federally that was completed. That's the first step to
5 weakening federal clean car standards and fuel economy
6 standards. We know that.
7 As we've heard, California's program isn't just
8 benefiting the health and welfare of California, but
9 residents from 12 other states. That's 113 million
10 people, one-third of the U.S. population.
11 Over the past decades this agency has seen
12 federal administrations come and go. But each time it's
13 stayed true to its principles that it will continue to
14 lead and protect the public health and the welfare when
15 others lag, and let the technical evidence be the primary
16 guide for setting standards. And the weight of that
17 evidence today shows that these standards are very much
18 achievable. Please reaffirm these standards and continue
19 moving us forward.
20 And now I'll let my colleague, Irene Gutierrez,
21 make some additional comments.
22 CHAIR NICHOLS: Thanks.
23 MS. GUTIERREZ: Good morning. Irene Gutierrez
24 with NRDC.
25 As my colleague, Simon Mui, has noted, I'd like

1 to thank the Board and the staff for the years of work
2 that have gone into putting together the Advanced Clean
3 Cars program. I'll make comments on two sections. I'll
4 comment on the ZEV Program and also on California's
5 regulatory authority.
6 As we've heard from the states, the ZEV Program
7 is a key driver for expanding markets in California and
8 other states. And we've seen cost-tipping points like
9 this in the solar and the wind industry. And the ZEV
10 Program is working. It creates a market for plug-in
11 electric vehicles and drives costs down and makes vehicles
12 more accessible to members of the population.
13 Automakers can readily meet the targets that ARB
14 has set. As we've noted in our comment letter, expert
15 analysis has shown that the likely sales targets to meet
16 the ZEV requirements in California is 6 percent by 2025.
17 This is lower than the original figure of 15.4 percent
18 sales. ARB's analysis shows that 8 percent sales by 2025
19 is needed and even Auto Alliance's study shows that only
20 10 percent sales are needed.
21 So by all metrics, the ZEV Program is well within
22 reach and becomes increasingly attainable over time as
23 vehicle technology improves and you see higher range
24 vehicles coming on to the market. So with this in mind,
25 we support ARB's recommendation to maintain the ZEV

1 standards through 2025, and we support the proposal to
2 continue strengthening the program for 2026 and beyond.
3 We look forward to working with ARB and other
4 State agencies on complementary policies to continue
5 supporting the program.
6 I'd also like to note that we support
7 California's staying firm in its commitment to protecting
8 state residents from air pollution and climate threats.
9 We're disappointed by some of the comments that have been
10 made by global auto makers and the Alliance of Automobile
11 Manufacturers. These groups are now arguing that even if
12 California committed to match federal EPA standards, that
13 it sticks with its commitment even if federal standards
14 are weakened. We closely followed this process, the
15 various negotiations that went on in 2009 to 2012, and we
16 know that this is not what California agreed to.
17 California never agreed to surrender its independent
18 regulatory authority and leave its residents at risk.
19 Industry groups misrepresent what the parties agreed to in
20 signing on to a national program; and they selectively
21 quote the statements made by California in its 2011
22 commitment letter, which states that California agreed it
23 would only accept compliance with the federal standards as
24 long as they remained as strong as those that were set
25 forth in 2011.

1 California did not agree to accept every change
2 to EPA standards and it doesn't need a permission slip to
3 go forward with its own.
4 So for these reasons, we support what ARB has
5 proposed and we look forward to working with ARB and staff
6 in the future.
7 Thank you.
8 CHAIR NICHOLS: Thank you, Ms. Gutierrez, and
9 thank you for your clarification on what was agreed to at
10 the time. We've seen a number of statements about that
11 that have been troubling, not just about the one national
12 program but also about the nature of the midterm review
13 itself, which never was intended to have to go out to the
14 full possible length. It was not something that was even
15 contemplated at the time, that it must extend further. It
16 was supposed to be done when it was ready to be done. So
17 the recent cries of process foul about the EPA decision,
18 even though we weren't apart of it, struck us as being
19 strange, to put it mildly, and certainly not based on the
20 agreement that we were a part of.
21 So thank you for your comments.
22 Mr. Lutsey.
23 MR. LUTSEY: Chair Nichols, Board members. Thank
24 you so much for all of your great work cleaning up vehicle
25 emissions. I'm Nick Lutsey. I'm with the International

1 Council on Clean Transportation. Just wanted to give a
2 few reflections here from some of our recent work.
3 First, we conducted a major technical study that
4 we just released this week. It analyzes technologies and
5 costs to reduce carbon dioxide emissions in the 2025 and
6 2030 time frame. Our work parallels and updates all of
7 the great work from ARB staff as well as EPA and NHTSA
8 staff. I'll highlight just a couple findings.
9 We find that previous government estimates,
10 including the MTR and the TAR by the agencies,
11 overestimate the compliance costs by 30 to 40 percent.
12 And that's due to all of the very low cost efficiency
13 technologies that keep emerging in the fleet.
14 These standards based on these low cost
15 technologies are extremely cost effective. The consumer
16 fuel savings tend to be two to three times higher than the
17 technology costs. And those findings are robust in that
18 they stand up even in low fuel prices.
19 If ARB maintains 2025 standards, this will
20 certainly help ensure that the U.S. auto market remains
21 globally competitive as Europe, China and elsewhere
22 continue to move forward with tougher standards for their
23 markets.
24 Second, we've done extensive work analyzing the
25 electric market -- electric vehicle market developments

1 around the world. Clearly California plays in a central
2 role as an incubator of electric vehicle technology. We
3 found that San Francisco and San Jose are among the global
4 leaders, with 6 percent and 10 percent of new vehicles in
5 those markets being electric vehicles today.
6 6 to 10 percent new electric vehicle sales is
7 essentially where the ZEV regulation would have us here in
8 California by 2025. So clearly the market is developing
9 much quicker than ARB had anticipated.
10 So as part of all this, the ZEV Program is
11 certainly a critical catalyst. It increases model
12 availability. It nudges automakers to develop and market
13 the cars. It provides the timetable for infrastructure
14 investments.
15 At this moment clearly it's important to look at
16 2030 policy. Costs are dropping. Great new electric
17 vehicles keep entering the fleet. And long regulatory
18 lead time is critical.
19 To close, California's role as an incubator is
20 extremely important internationally. All of the
21 collaborations with Norway, the Netherlands, Quebec are
22 growing the global scale of ZEV technology. So thanks for
23 all your great work. It's really important to see all
24 these developments and make sure they do become global
25 developments.

1 Thank you.
2 CHAIR NICHOLS: Thanks.
3 Hold on just a second. I think Dr. Sperling
4 wants to say something.
5 BOARD MEMBER SPERLING: I want to just
6 acknowledge that Nick Lutsey played a very key role back
7 in developing the 2012 -- doing the technical work behind
8 the 2012 standards. Brilliant work, and also happens to
9 be one of my former students.
10 (Laughter.)
11 CHAIR NICHOLS: This is not a paid commercial.
12 (Laughter.)
13 MR. LUTSEY: Thank you, Professor Sperling. I
14 was taught very well. I really appreciate it.
15 (Laughter.)
16 CHAIR NICHOLS: Thank you. Thank you for that.
17 Okay. Next up we have Chet France from EDF.
18 Mr. France was also involved at the time in the 2012
19 process, and brings that expertise to this discussion as
20 well.
21 MR. FRANCE: Thank you, Chair Nichols and the
22 Board. These are topics that are very near and dear to my
23 heart.
24 On behalf of the Environmental Defense Fund and
25 more than 2 million members nationwide, I thank you for

1 the opportunity to speak today.
2 I want to offer our recommendations on the
3 midterm review and the post 2025 clean car standards. We
4 agree and support the staff's conclusion that the current
5 model year 2022 to 2025 standards remain appropriate.
6 Given the substantial and compelling record, we
7 recommend that the Board reaffirm California's commitment
8 to the current federal standards. These standard -- these
9 recommendations are based on extensive technical record
10 that included multiple opportunities for public comment
11 engagement and input.
12 The final determination in supporting analysis
13 show automakers and suppliers are developing and deploying
14 fuel-efficient technologies at a much faster rate than was
15 forecasted in the 2012 final rule. And they're doing it
16 as costs that are lower than projected in that rule.
17 The standards will be met with advances in
18 conventional technologies such as engine and transmission
19 improvements, lightweighting, and better aerodynamics.
20 These improvements have come alongside a dramatic rebound
21 in the auto industry. Vehicle exports are up. Sales are
22 at an all-time high, and the industry has added over
23 700,000 jobs since 2009.
24 Next slide please.
25 --o0o--

1 MR. FRANCE: Though the technical record
2 supports even more protected standards for 2022 to 2025,
3 EDF believes that the better approach is to strengthen the
4 standards for model year 2026 and beyond. Accordingly, we
5 recommend that the Board direct the staff to begin work on
6 strengthening the Greenhouse Gas and ZEV Program for 2026
7 and beyond.
8 EDF recently sponsored a study that examined
9 reductions that may be possible in the 2030 time frame.
10 Tom Cackette, who will follow me, who was one of the
11 authors, will provide the Board with a separate
12 presentation on the specific details of the report.
13 Though as a general matter, it confirms the feasibility
14 and cost effectiveness of deep CO2 reductions.
15 The major findings of the report are there are
16 under-utilized conventional technologies available to
17 further reduce CO2 emissions, the cost of lithium ion
18 batteries is declining rapidly, widespread introduction of
19 ZEV models is possible by 2030, and the availability of
20 cost competitive ZEV technologies opens a technological
21 pathway for all OEMs to achieve very large CO2 emission
22 reductions.
23 This analysis provides strong technological,
24 economic, public health, and environmental reasons for
25 initiating work necessary to begin defining the post 2025

1 Clean Car and ZEV Program.
2 Next slide.
3 --o0o--
4 MR. FRANCE: In conclusion, we recommend that
5 the Board reaffirm California's commitment to the current
6 2022 to '25 standards and direct the staff to begin work
7 on strengthening the Greenhouse Gas and ZEV Program.
8 Thank you for your leadership on these issues,
9 and thank you for considering our comments.
10 CHAIR NICHOLS: Thank you.
11 Are you aware of any new studies or reports or
12 other technical information that would call for a
13 reopening of the midterm review?
14 MR. FRANCE: No, I'm not. And this has been a
15 multi-year effort. I think it's more extensive than I've
16 ever seen in my whole career.
17 CHAIR NICHOLS: Okay. Thank you.
18 Mr. Cackette, welcome back.
19 (Thereupon an overhead presentation was
20 Presented as follows.)
21 MR. CACKETTE: Thank you. Appreciate the
22 opportunity to share with you the study that Chet
23 mentioned, which a colleague and I prepared for the
24 Environmental Defense Fund. And that study is looking at
25 the opportunities and the potential for achieving greater

1 CO2 emission reductions in the post 2025 standards, so --
2 future standards for the next five years or so.
3 I need to give you a little bit about the study
4 and what we did. First of all, we used the tool that you
5 used and that EPA used to do the TAR, the Technical
6 Assessment Report, and the Preliminary Determination
7 Report; and we made very few adjustments to it. We only
8 extended its modeling domain from 2025, which was the
9 purpose of this meeting, to 2030, and we used some updated
10 information which showed that the -- in the 2030 time
11 frame the cost of manufacturing a ZEV was going to
12 continue to decline.
13 And we have a number of scenarios, but I'm just
14 going to share just one with you.
15 So next slide please.
16 --o0o--
17 MR. CACKETTE: So this is the -- this slide shows
18 some of the key inputs and outputs that we came from the
19 study.
20 As an input, this shows you the declining costs
21 of manufacturing different types of ZEVs over time. So
22 you can see right now we're up there in the, you know,
23 $15,000 range. But you can see that by 2030, a
24 hundred-mile BEV is cheaper to manufacture than an
25 internal combustion engine vehicle. So this is the kind

of -- this is important input that shows why ZEVs will be popular and effective in the future.

Click please.

--o0o--

MR. CACKETTE: A couple study results. One is we looked at a scenario where there were no ZEVs available and how much conventional technology could do. And we found that you could do more than the 2025 standards but only in the range of 10- to 30-gram-per-mile reduction from the current standard.

--o0o--

MR. CACKETTE: But when we let ZEVs come into the model for selection with these prices I just showed you, then you could go all the way to 90-grams-per-mile reduction, which is taking 173-gram standard and making it an 83-gram standard. So a very big reduction.

So next slide please.

--o0o--

MR. CACKETTE: This is the results. And I'm going to -- follow the colors, if you would.

We looked at 10-gram increments. And so here's a 50-gram increment and a 90-gram increment, and -- next slide please.

--o0o--

MR. CACKETTE: -- you can see that the costs are

1 certainly there. There's a prices increase that the
2 consumer would see. But you can also see that the fuel
3 savings are two to three times as large as the capital
4 costs of the vehicle.
5 Next slide.
6 --o0o--
7 MR. CACKETTE: The payback period is five years.
8 The average person keeps a vehicle for 6.5 years on a new
9 vehicle.
10 And, finally, the number of ZEVs that would be in
11 the mix to achieve these standards at 50 grams per mile is
12 21 percent and then 40 percent. So a big increase beyond
13 what we have now but clearly feasible.
14 And final slide.
15 --o0o--
16 MR. CACKETTE: This is a pathway from your staff
17 that shows how many ZEVs you need to achieve the 80
18 percent reduction in emissions by 2050 that the Governor
19 has set as executive order.
20 --o0o--
21 MR. CACKETTE: And the next slide shows you where
22 these two scenarios fall on the curve. If you achieve a
23 90 percent re -- 90-gram reduction by 2030, you're right
24 on the curve towards the 2050 goal of 80 percent reduction
25 from this sector. And if the number is less than that at

50, you could see that you're somewhat below the line and would have to play catch-up in the later years after 2030.

So thank you very much.

CHAIR NICHOLS: Thanks. Before you go, Dr. Balmes had a question for you.

BOARD MEMBER BALMES: I'm not going to take credit for you being my student. I think it was the other way around.

(Laughter.)

BOARD MEMBER BALMES: But I am going to ask you, since you were the one that suggested I buy a diesel TDI Jetta --

(Laughter.)

BOARD MEMBER BALMES: -- what have you done with yours?

(Laughter.)

MR. CACKETTE: Well, I have one and my daughter bought one two weeks before the announcement that they were going to -- they had cheated.

So we still have them, but we're both going to sell them back. And I'm buying an electric vehicle to replace it.

(Laughter.)

(Applause.)

BOARD MEMBER BALMES: I already have.

1 CHAIR NICHOLS: To allow you to rebuild your
2 credibility here,
3 (Laughter.)
4 MR. CACKETTE: Please help me, Madam Chair.
5 CHAIR NICHOLS: Let me just ask you a question
6 actually about your comment about the 100-mile BEVs.
7 Because, not to speak for the manufacturers, but others
8 have commented independently that they don't really see
9 consumers making a big move to battery electrics -- full
10 battery electrics with less than the 200-mile range.
11 What's your opinion on that?
12 MR. CACKETTE: Well, that scenario that we
13 presented included a 50 percent mix of 100-mile BEVs and
14 the other 50 percent being 200-mile. And I don't really
15 know what people are going to select. If 200 miles is,
16 you know, a thousand dollars more than a hundred miles,
17 you know which one you're going to buy. But if there's a
18 bigger price difference, I think there will be some sales
19 of lower ones for urban use as a second car - that's kind
20 of what we're doing with all the Leafs that are out there
21 now, for example - and other people that want to try to
22 make this vehicle as primary vehicle will go for the 200
23 miles and pay the extra money. So I think it will be a
24 mix.
25 And we didn't show any plug hybrid electric

1 vehicles in there, because they're actually a more
2 expensive choice for manufacturing. But from a consumer
3 standpoint, a lot of people that want one car are going to
4 go for the Volt-like vehicle and use it urbanwise
5 electric. And so I think there will be a mix of those as
6 well.
7 CHAIR NICHOLS: Thanks.
8 Okay. Rasto Brezny from MECA.
9 DR. BREZNY: Good morning, Chair Nichols and
10 members of the Board. I'm Rasto Brezny, the Executive
11 Director for the Manufacturers of Emission Controls
12 Association.
13 MECA members supply the many technologies that
14 allow light-duty vehicles to comply with both the
15 greenhouse gas and the criteria pollutant requirements
16 under the Advanced Clean Cars program. These include
17 things like fuel injection, turbochargers, all the way out
18 to 48-volt technologies, and the types of catalysts and
19 filters that are required for these different powertrains
20 to achieve criteria pollutant requirements. So we agree
21 with staff's conclusions and their recommendations.
22 So I want to focus on an area where we feel that
23 more can be done sooner. And this is in the area of PM
24 reduction.
25 PM -- we know that PM is really not just an

1 inventory issue. It's also a health issue; it's a climate
2 issue with black carbon; and its a toxics exposure issue
3 as well.
4 So, you know, we expect that by 2025, half the
5 new vehicles made are going to come equipped with the
6 gasoline direct-injected engines. So we've spent a lot of
7 time characterizing the PM from these vehicles, and we
8 know that the GDI PM is very similar to the diesel PM. It
9 has many of the same components, as well as the black
10 carbon that's contained.
11 Other parts of the world have chosen to address
12 this change in fleet mix by establishing particle number
13 standards. And Europe will adopt these in 2017, later
14 this year; China, in 2020; and India, in 2023. The
15 particle number standard is roughly equivalent to half a
16 milligram per mile.
17 So you see that the same manufacturers that sell
18 cars in California are going to have to comply with much
19 tighter PM standards in other parts of the world sooner
20 than 2025.
21 So we've -- numerous studies have shown that, you
22 know, these low PM levels can be achieved either through
23 better fuel injection technology or gasoline particulate
24 filters. And there's a number of vehicles on the road
25 today that are exceeding the one milligram standard.

1 So catalyzed GPFs go a step beyond that by not
2 only reducing the black carbon, but also the toxics and
3 other compounds that are associated with the PM by over 90
4 percent, with no impact on CO2 or fuel economy.
5 So we'd like to work with your staff to look at
6 voluntary incentives that could be used to incentivize
7 this best available control technology here in the U.S.
8 through a modest CO2 credit for achieving the
9 one-milligram standard sooner by putting on the best
10 available control technology on these vehicles.
11 Thank you.
12 CHAIR NICHOLS: Thanks.
13 Mr. Noyes.
14 MR. NOYES: Good morning, Chair Nichols, members
15 of the Board. My name is Graham Noyes. I'm the Executive
16 Director the Low Carbon Fuels Coalition. We're an
17 organization dedicated to the support and expansion of low
18 carbon fuel policies.
19 We provided detailed written comments for the
20 record. I will move through them quickly, but would
21 recommend those for any points that are raised here that
22 you'd like to look at in more depth.
23 And we come forward neutral. We certainly
24 recognize the great work by staff that went into this
25 report and the very -- excuse me -- challenging situation

1 that we're in -- sorry, I've got an allergy raising here.
2 California's plan relies upon EPA's final
3 determination in NHTSA. But when Senator Chao and --
4 Secretary Chao and Administrator Pruitt signed the notice
5 of intention to reconsider the final determination of
6 greenhouse gas standards for model year 2022 through 2025
7 light-duty vehicles, that was a game changer. And we
8 recommend to staff and to the Board to recognize that that
9 was a game changer. The automakers are effectively on a
10 five-year time frame, and so 2022 is today from that
11 perspective. We've now seen the federal process open.
12 And the midterm review itself recognizes that the findings
13 would likely be different if the stringency of the
14 national greenhouse gas standards were substantially
15 changed.
16 So our recommendation is that the Board keep the
17 Advanced Clean Car rule -- the midterm review open, and
18 establish a return to the Board to discuss what's
19 happening on the federal front, so that California can
20 remain nimble on its feet and be aware of what's happening
21 with the changing federal landscape here.
22 We also recommend that California build flex fuel
23 vehicles and mid-level ethanol blends back into its policy
24 program. Those have proven to be very successful in terms
25 of reducing petroleum dependence and also delivering

1 greenhouse gas reductions. We've seen the carbon
2 intensity of ethanol drop to about 20 percent less than
3 gasoline. Of course ethanol substitutes completely for
4 gasoline as a fuel. So to achieve those two goals
5 California's invested millions in a network of E85
6 stations and 20 million gallons of E85 was delivered last
7 year into California vehicles. Those vehicles provide
8 reductions in disadvantaged communities, as is required by
9 AB 197, so it's an on-the-ground solution. And as NREL
10 has said, FFVs can provide a bridge between our current
11 situation to the future realm of new vehicles.
12 So our specific recommendation is for the Board
13 to receive an update in three months that includes a
14 review of integrating a flex fuel vehicle/mid-level
15 ethanol blend component into the Advanced Clean Cars rule.
16 And our perspective is that in a dynamic federal
17 landscape, California's going to need to be both tough and
18 flexible to achieve its goals.
19 Thank you.
20 CHAIR NICHOLS: Thanks. Tough and flexible.
21 Sounds like a pretty good mantra.
22 Ken Morgan. Morning.
23 MR. MORGAN: Hi.
24 Chair Nichols, members of the Air Resources
25 Board. Thank you for the opportunity to speak here today.

1 My name's Ken Morgan. I'm with Tesla.
2 And I guess I'll just start by saying we're very
3 excited to be launching our Model 3 vehicle this year.
4 That's a car that is fully electric, zero emission,
5 $35,000, with over 200 miles of range.
6 And just a quick note on market acceptance. With
7 that vehicle, within the first two months of announcing
8 unveiling that car, we received 373,000 deposits
9 worldwide. And many of those deposits were from
10 California customers. So the market is certainly there
11 for the right type of vehicle, and we're looking forward
12 to getting that off the production line.
13 And just a quick note on the midterm review.
14 Clearly this is a very critical moment in the history of
15 the ZEV movement. And certainly your decision here today
16 will have an impact, and the guidance you provide will
17 have an impact on the next decade of investment by the
18 automotive community in this technology. And we know this
19 because the federal regulations, Greenhouse Gas Cafe, can
20 be met with incremental improvements to existing
21 combustion engine technologies. So it really is the --
22 California's regulation that is driving these near-term
23 investments in pure zero-emission technology, and that's
24 why it's so critically important. And certainly also
25 important to hitting some of the emissions goals that were

1 outlined by the staff earlier.
2 As Anna mentioned during her presentation, in
3 terms of the technical assessment of the trajectory of the
4 ZEV mandate -- and I do just want to recognize briefly
5 that the staff has done a fantastic job with the technical
6 review of the ZEV regulation. But she mentioned staying
7 the course. And so I think it's just important to note
8 that the course that was set in 2012 was 15 percent of
9 sales by 2025. And so if we choose to make no change to
10 the regulation, in fact we are setting a new course that's
11 been reviewed by both staff and other folks that have run
12 this analysis, that's about half of that trajectory that
13 was anticipated when the credit targets were set in 2012.
14 So we certainly feel that it's really important
15 to look at this credit oversupply and to make a decision
16 to amend the regulation as soon as possible to get us back
17 on track to hit some really significant milestones by
18 2025, such that we are on an upward slope towards that
19 2030 goal.
20 As the staff have outlined in their scoping plan
21 update, we need something in the order of 4.2 million
22 plug-in cars by 2030 to hit the state goal of 40 percent
23 GHG emissions reduction. But the current trajectory of
24 the regulation only gets us to 1.2 million by 2025. So
25 it's pretty heavily backweighted today, and I think that

1 does put the 2030 goal at risk. So we certainly would
2 recommend that the Board take some near-term action as
3 quickly as possible to address the oversupply of credits.
4 Thank you.
5 CHAIR NICHOLS: Thank you.
6 MS. HOLMES-GEN: Good morning, Chair Nichols and
7 Board members. Bonnie Holmes-Gen with the American Lung
8 Association in California; and also a proud ZEV owner of
9 over three years.
10 California's leadership on clean cars is
11 providing tremendous returns in health and clean air
12 benefits, not just for California but for all the ZEV
13 states and indeed around the world. We have been pleased
14 that the American Lung Association be able to quantify
15 those benefits in own report, Clean Air Future, that we
16 released last fall. And I wanted to just talk for a
17 moment about some of those health benefits.
18 Our report finds a widespread shift to
19 zero-emission vehicles in all the ZEV states, a shift that
20 builds on our current ZEV regulation, Advanced Clean Cars,
21 and ramps up to 65 percent of ZEVs in our fleet by 2050
22 would bring tremendous health benefits. And this would
23 bring benefits to millions of people in all of our states.
24 The public right now is bearing a huge cost, billions of
25 dollars annually in health expenses and climate damage

1 from our dependence on petroleum fuels.
2 Or to bring it down to a more personal level, for
3 each 16-gallon tank of gas we're burning, it costs society
4 about $18.42 in health and climate impact costs. This is
5 a very conservative estimate and only looking at the
6 passenger vehicle sector. So moving to zero emission,
7 it's going to dramatically reduce these costs and increase
8 the benefits to public health.
9 Here's the bottom line. A robust ZEV Program in
10 2050 would result in over 90 percent reduction in
11 emissions that generate smog and soot from vehicles,
12 around 85 percent reduction in health impacts, and more
13 than a 50 percent reduction in greenhouse gases from
14 passenger vehicles compared to 2015, which is similar to
15 taking all the cars off the road in the Northeast states.
16 And this adds up to a savings of over $33 billion. And
17 that's 20 billion in health savings alone across the
18 zero-emission vehicle states.
19 This is an enormous advance for public health.
20 We can break it down and look at:
21 Reductions in asthma attacks. 96,000 fewer
22 asthma attacks.
23 Reductions in lost work days and reductions in
24 premature deaths. Over 2,000 fewer premature deaths.
25 We have all this data. We've shared it with you.

1 But I want to make sure that we've brought it into clear
2 focus today as you're looking at this important regulation
3 and determining the future.
4 To conclude, please direct the staff to move
5 forward quickly now, to build on the next phase of
6 Advanced Clean Cars and Zero-Emission Vehicle programs to
7 keep us on track to meet our climate goal and realize
8 these tremendous health benefits. And please keep the
9 particulate matter controls on track as staff is
10 recommending.
11 Thank you very much.
12 CHAIR NICHOLS: Thank you.
13 Eileen Tutt.
14 MS. TUTT: Chair Nichols and members of the
15 Board. Good morning. My name is Eileen Tutt. I'm with
16 the California Electric Transportation Coalition.
17 I'm not going to repeat anything that's in our
18 letter. We completely support the staff recommendation
19 specifically regarding the ZEV part of the program. And
20 we're really happy to be working with them throughout the
21 whole process. So we found them to be, as usual, very
22 pleasant and responsive to work with.
23 I do want to just point out something because I
24 didn't see it really highlighted in Anna's presentation;
25 and you'll not be surprised to hear me say this. The ZEV

1 Program is on track and we're glad you're going to keep it
2 on track hopefully. We are -- California is clearly
3 committed to zero-emission vehicles. But probably the
4 number one threat to the continued market acceleration
5 beyond even the rates we're at today is the fact that we
6 just don't have a reliable incentive program in place.
7 And so we really, really need that. And I'm worried about
8 the federal incentives. Actually I'm worried about much
9 more than that. Federal government.
10 (Laughter.)
11 MS. TUTT: But I also -- I just think it ought to
12 be a no-brainer that in California we would have a
13 reliable incentive program. So I just hope that you have
14 not forgotten that, and I'm sure you won't.
15 But I want to say, so thank you for your
16 consideration, and I hope that today turns out the way I
17 think we all hope it will turn out.
18 BOARD MEMBER SPERLING: Can I ask a question?
19 CHAIR NICHOLS: Yes, go head.
20 BOARD MEMBER SPERLING: What do you mean by a
21 reliable incentive structure? What would that be?
22 MS. TUTT: Well, we have a budget proposal. So
23 thank you, Dr. Sperling, for asking that question.
24 (Laughter.)
25 MS. TUTT: I think what we would like to see

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1 ideally, not just for light-duty vehicles but for medium-
2 and heavy-duty vehicles, we would like to see 650 million
3 appropriated annually for the next five years either from
4 greenhouse gas reduction fund - so we definitely need to
5 reauthorize cap and trade - and/or through some sort of
6 tax incentive structure. That's our proposal. And I'm --
7 I will actually make sure you get a copy of it.
8 BOARD MEMBER SPERLING: Thank you.
9 CHAIR NICHOLS: Okay.
10 MR. HOUGH: Good morning, Chair Nichols and Board
11 members. I'm Merlyn Hough. I'm director of Lane Regional
12 Air Protection Agency in Lane County, Oregon. Lane County
13 is about the same size as Connecticut. But we --
14 (Laughter.)
15 MR. HOUGH: But we don't have level 2 chargers
16 every 20 minutes yet.
17 (Laughter.)
18 MR. HOUGH: We were formed in -- we're a local
19 air agency formed in 1968 under the Oregon statutes. I
20 won't repeat the written comments since it's really just
21 repeat -- supporting many of the things already said. We
22 strongly support the ARB staff recommendations. We're
23 very encouraged by the midterm evaluation and the midterm
24 review by EPA and the national highway traffic safety
25 folks and Air Resources Board. We're encouraged that

there's even more technologies available for manufacturers to meet the 2022-2025 standards; more than we expected back in 2012 and at similar or lower costs than estimated back there.

I've also provided copies of more detailed comments by the National Association of Clean Air Agencies, so that's in the record. And as already been stated, you know, the ZEV portion of your midterm review is not just important for meeting California's goals but also for the multi-state ZEV Action Plan states, the Section 177 states that's been discussed already.

I'm also a member -- Lane Regional Air Protection Agency's also a member of Drive Oregon, and I could try to respond to that question from earlier. Leah Feldon and Dave Nordberg from Oregon DEQ and I put our heads together. There's so much happening with Drive Oregon. Several initiatives in the Oregon legislature. But we decided you were probably asking about the showcase center that's being planned for downtown Portland. That's part of a $1 million grant from U.S. Department of Energy, a multi-faceted outreach program. But that storefront center is intended to complement the Electric Avenue that's downtown already. There's several quick charging and level 2 stations that are available right down there by the Portland General Electric offices. That's the

other P.G.E. on the West Coast. And that is to provide brand neutral sales folks able to provide ride and drive opportunities and also long-term electric vehicle rental and provide complete and balanced information as a major part of that outreach. So if that was --

CHAIR NICHOLS: That was the question. It was, yes. Thank you.

MR. HOUGH: So thank you for this opportunity. And please keep up all your good work. We're very appreciative of what you have done over the years. You've reduced vehicle emissions and increased fuel economy. It's -- you know, whether you're talking air toxics or ozone precursors or greenhouse gases, transportation emissions are a big deal.

Thank you.

CHAIR NICHOLS: Thank you.

Okay. I was just handed another whole page of people who want to comment, so we'll move along.

MR. SHUMAKER: Good morning, Chair Nichols and members of the Board I am Cory Shumaker, Project Coordinator of the California Hydrogen Business Council, a California industry trade association with a mission to advance commercialization of hydrogen in transportation and stationary applications to reduce greenhouse gases, criteria pollutant emissions and dependence on oil.

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1 The California Hydrogen Business Council would
2 like to voice its strong support for continuing
3 California's commitment to bring 1.5 million zero-emission
4 vehicles on California's roads by 2025, supported by
5 strong policies like the ZEV mandate. The CHBC sees
6 California's leadership as essential in accelerating the
7 transition to electric vehicles, including fuel cell
8 electric vehicles, which reduce air pollution and improve
9 public health specifically in disadvantaged communities.
10 The hydrogen and fuel cell community is showing
11 strong economic growth, stimulated by the policy framework
12 developed through California's commitment to clean and
13 emission-free technology for transportation and other
14 industry sectors.
15 The CHBC strongly encourages the Board to look
16 beyond the 2025 standards and start developing policy
17 recommendations especially for zero-emission vehicles and
18 infrastructure support for the post 2025 time frame.
19 Thank you.
20 CHAIR NICHOLS: Okay. Thanks.
21 MS. REYES: Good morning, Chair Nichols and
22 members of the Board. I'm Susana Reyes with L.A. Mayor
23 Eric Garcetti's Sustainability Team.
24 On behalf of the mayor, I am here to thank you
25 and your staff for the wonderful report. And I am here to

1 voice his support for your determination of the
2 appropriateness of the Clean Car Standards Midterm Review.
3 Los Angeles has a long history of some of the
4 greatest air quality challenges in the nation. Yet we
5 have come a long way, due in part to the work of the Air
6 Resources Board, and for that we are thankful. This
7 progress must continue. The mayor is absolutely committed
8 to clean vehicles. He has required that at least 50
9 percent of our annual city fleet procurement be pure
10 battery electric.
11 We have ensured that Los Angeles Department of
12 Water and Power offer generous residential and commercial
13 rebates for its charging stations. There are 1300
14 publicly available charging stations throughout the city,
15 beating our 2017 goal of 1,000. And we have partnered
16 with your agency to launch a new low income EV car share
17 in Los Angeles, and the grant will enable the
18 disadvantaged communities to access clean, pure electric
19 battery cars and to take advantage of 200 charging
20 stations in the pilot areas by the end of this year.
21 But L.A. is not alone in its commitment to clean
22 vehicles. With 29 other mayors across the country, Mayor
23 Garcetti recently issued an EV Request for Information,
24 and this EV RFI demonstrated to OEMs and manufacturers
25 that these 30 cities have over 114,000 vehicles that could

be electrified, representing over $10 billion in potential investment in EV sedans, trucks, and vehicles of various types. We have received 37 responses to the RFI so far. And that's a very encouraging sign that we can make this happen.

So we applaud the Air Resources Board's efforts to improve air quality and reduce greenhouse gas emissions through increasingly robust clean-car standards that keep California at the forefront of environmental protection and innovation.

Thank you for this opportunity.

CHAIR NICHOLS: Thank you. Thanks to the city of Los Angeles for all you guys are doing.

MS. PHILLIPS: Kathryn Phillips with Sierra Club California.

As you can imagine, we're very disappointed by what we're seeing at the federal level; so today, feels very warm and welcoming. And we want to thank for continuing your commitment to clean air and the ZEV Program.

One of things that has helped prevent the level of ZEV adoption that everything else points to meeting to happen and that should happen and that could happen is the actions by the automakers and the dealers themselves in their lack of applying best practices in this sales of

1 vehicles.
2 Recently, last spring Sierra Club volunteers --
3 Sierra Club put together a report where we basically did a
4 shopping experiment. And 174 volunteers around the
5 country in the ten ZEV states visited 308 dealerships.
6 And some of the things they found are pretty discouraging.
7 When you consider how much effort has gone into making
8 sure that the technology is right, we still have not been
9 able to rely on the auto dealers and the automakers to
10 work as well together as they need to to sell these
11 vehicles and make them available.
12 Nearly half the time EVs were not prominently
13 displayed or were often hard to find. They were hidden
14 some place on the lot if they were there at all. Sales
15 people failed to mention state and federal incentives, and
16 those can be a big draw for EVs.
17 Some of the cars couldn't be test driven because
18 they weren't charged. That was in 14 percent of the
19 cases. When you're talking about 388 dealerships --
20 rather 308 dealerships, 14 percent is pretty high. Can
21 you imagine going in to drive a gasoline-powered SUV and
22 them saying, "I'm sorry, we don't have any gas in it. You
23 can't try it"?
24 (Laughter.)
25 MS. PHILLIPS: Only half the time sales people

1 told these shoppers how to charge the vehicle while
2 traveling. So they were left with the impression that you
3 either had to stay in your neighborhood or be at a big
4 disadvantage.
5 Another interesting thing is that the dealers
6 themselves had complaints. Sometimes the automakers
7 charge these certification fees. Some automakers don't
8 charge them. But one dealer complained about being
9 charged $50,000 to do -- for a certification fee. So
10 because of that we wouldn't carry EVs.
11 So I think, in conclusion, that the automakers
12 and the auto dealers themselves can do a much better job
13 of making sure that these vehicles sell.
14 Thank you.
15 CHAIR NICHOLS: Thanks.
16 We have -- excuse me, before you speak. We just
17 got one more card in. And I think that's it, we're going
18 to cut off any additional witnesses at this point. We've
19 got a robust discussion here.
20 Thanks.
21 MS. ADAMS: Hi. My name is Kitty Adams. I'm the
22 Executive Director of Adopt a Charger. And I'm grateful
23 that I can be here today to thank CARB for the ZEV
24 mandate. I want to encourage you to continue this work,
25 you know, beyond 2030.

1 And I also wanted to just comment because -- in
2 response to some of the automakers' presentations
3 specifically about range anxiety. I'm on the front lines
4 of trying to sell cars, and I really hear more about lack
5 of appropriate body style than range anxiety. I jokingly
6 say to people when the Ford F-150 comes with a plug, I can
7 retire because these cars are going to sell themselves.
8 So I just want to make sure that we encour -- do
9 everything we can to encourage the automakers to offer
10 zero-emission vehicles across the whole range of their
11 offerings.
12 And also too is really alarming for me to see the
13 presentations from Connecticut and Maryland and
14 Massachusetts and -- where they have -- they're
15 participating but they don't have the cars to sell. So if
16 there's anything California can do to force the issue and
17 make the automakers make these cars available in all 50
18 states, I think that would be a very advantageous
19 direction to move in.
20 Thank you.
21 MS. HOLMES: Good morning. I'm Laurie Holmes,
22 Senior Director of Environmental Policy for Motor and
23 Equipment Manufacturers' Association, or MEMA.
24 MEMA represents more than 1,000 companies --
25 motor vehicle companies that supply motor vehicle

1 companies -- sorry -- 1,000 companies that supply motor
2 vehicle components for use in the original-equipment and
3 aftermarket industries.
4 Motor vehicle suppliers play a significant role
5 in developing innovative materials technologies that
6 improve vehicle performance, fuel efficiency and
7 emissions, and are committed to environmental policies
8 that enable the introduction of new technologies.
9 MEMA supports ARB's continued alignment with the
10 national program by maintaining that deem-to-comply
11 provision allowing for compliance with the adopted EPA
12 greenhouse gas national standards. This deem-to-comply
13 provision is extremely important to the success of the
14 national program.
15 MEMA strongly supports consistent greenhouse gas
16 standards at the state and federal level and urges
17 California to continue to focus on collaborating with EPA
18 and NHTSA on a harmonized true national program. A
19 harmonized national program provides long-term regulatory
20 clarity and certainty that are critical for suppliers to
21 make the necessary long-term business and technology
22 investment decisions.
23 MEMA supports the conclusion of ARB to maintain
24 the phase-in of the 1 milligram per mile PM standards
25 starting in model year 2025. Maintaining that standard

1 provides regulatory certainty necessary for MEMA's members
2 to commit the requisite research and development to assist
3 manufacturers in meeting future regulations cost
4 effectively.
5 As we've also heard in the other comments, MEMA
6 urges ARB to provide further flexibility in the ZEV
7 mandate. So further flexibility for the plug-in hybrids
8 by allowing OEMs to comply with more PHEVs than what is
9 currently allowed in the regulations through model year
10 2025. MEMA believes that PHEVs can serve as the
11 successful transition to ZEV technology by appealing to a
12 broader market, especially under the current market
13 situation.
14 MEMA would also support ARB working with industry
15 to develop an additional test cycle similar to the one
16 described in appendix H to measure PHEV tailpipe criteria
17 emissions more thoroughly. This additional test cycle
18 could then be used to provide additional ZEV Program
19 performance-based credits that incentivize tailpipe
20 criteria emissions controls technology for PHEVs, which
21 would provide incentives that would move the ZEV Program
22 to more fair, balanced, and performance-based driven
23 standards and solutions.
24 Thanks for your time.
25 MR. BOESEL: Good morning, Chairman Nichols and

1 members of the distinguished California Air Resources
2 Board. My name is John Boesel. I'm the President and CEO
3 of CalStart.
4 I want to make clear it's Boesel, not Boesella.
5 (Laughter.)
6 MR. BOESEL: We are a national nonprofit
7 organization working to build the clean transportation
8 technologies industry as a strategy to produce -- provide
9 high quality jobs, improve public health, and prevent
10 global warming. Though our members are working on a wide
11 array of technologies and fuels, they all share a common
12 belief that innovation can solve our challenges.
13 I'm standing here today to strongly endorse the
14 staff recommendations while wishing their was an
15 opportunity to do even more.
16 Looking back to 2012 when the Advanced Clean Car
17 Programs was adopted, it's impressive to see how much
18 progress and innovation has occurred, in large part due to
19 joint policies of the ARB, EPA, NHTSA, and the Section 177
20 states.
21 I want to describe the progress and why we
22 support the staff recommendations with the following four
23 points:
24 First of all, California is now the home to three
25 emerging light-duty electric vehicle manufacturers;

1 Faraday Future, Karma Automotive, and Tesla Motors. These
2 companies are here because California is where the action
3 is and because of ARB's policies. This is also where a
4 lot of great talent is.
5 Tesla is now the largest manufacturer in the
6 State of California, period, end quote -- or stop -- hard
7 stop.
8 (Laughter.)
9 MR. BOESEL: Tesla has 22,000 employees in its
10 combined operation with Solar City in the state of
11 California. There are a lot of other states that would
12 kill for -- to get those job.
13 Charge Point, the nation's largest EV charging
14 company, is also based here in California.
15 California is also home to the U.S. headquarters
16 and operations of BYD, who presently focus on electric
17 buses and trucks in the United States. BYD was the
18 largest manufacturer of electric cars in the world in
19 2016, and submitted a letter yesterday strongly endorsing
20 the staff's recommendations and the ZEV targets.
21 Since 2012, when the program was announced, it's
22 also been very exciting to see how the global automobile
23 industry has moved in mass to Silicon Valley. Not
24 including Tesla or your traditional mechanics and dealer
25 jobs, there are probably 4,000 new jobs related to the

1 automotive industry in the Silicon Valley alone that have
2 occurred since 2012.
3 Secondly, the ZEV technology, the technology has
4 improved incredibly since 2012. We've seen basically the
5 same battery pack in the -- at the same price in 2012 is
6 now -- and you can go from 75 miles to 230 miles in that
7 same pack. I want to give General Motors a lot of credit
8 for what it's done.
9 Also, per -- a study we did on Tier 1
10 suppliers -- shoot.
11 (Laughter.)
12 MR. BOESEL: They are very committed to investing
13 in the future of technology.
14 So let me just wrap it up even though I had a few
15 more points, which I'll submit in writing, is that we see
16 at least four OEMs right now between Faraday Future, BYD,
17 Volkswagen -- or at least three willing to say that they
18 support the standards. And that was something that was
19 very different from 2012.
20 And then some very strong comments by BMW CEO
21 basically saying that by 2025 they see 15 to 25 percent of
22 all sales being electric vehicles, which is basically an
23 endorsement of the standard as well.
24 Thank you very much.
25 MS. KINMAN: Good morning. If only that dolly

1 were as smooth a drive as my EV, I'd be in a good spot
2 this morning.
3 My name is Michelle Kinman, and I'm the clean
4 energy advocate for Environment California Research &
5 Policy Center. And I'm very pleased to present some of
6 the more than 10,000 petitions that Californians all
7 across the state have signed expressing strong support for
8 the ZEV mandate. These petitions were gathered by
9 organizations representing the environmental, public
10 health, scientific, consumer, and faith communities,
11 including the American Lung Association in California, the
12 Coalition for Clean Air, CalPIRG students from UCLA and UC
13 Riverside, California Interfaith Power & Light, Plug In
14 America, Sierra Club California, the Union of Concerned
15 Scientists, Environment California.
16 This diverse set of voices is united behind the
17 following petition statements, quote: Yes, I want more
18 zero-emission vehicles on the road and support strong
19 policies like the ZEV mandate that will lead to at least
20 1.5 million ZEVs on California's roads by 2025. By
21 accelerating the transition to electric vehicles we can
22 clean up our air and improve public health, especially in
23 our most disadvantaged -- or, excuse me -- polluted
24 communities; reduce global warming pollution; save
25 Californians money at the pump; and stimulate economic

growth, end quote.

I would like to thank the ARB for your long leadership on clean vehicles. Now more than ever, with the administration in DC threatening to put the brakes on cleaner vehicles, your continued leadership is essential, and we urge you to enact more stringent standards now and in post 2025.

On a separate but complementary note I would also like to present a letter prepared by my colleagues at Environment America to President Trump and signed by more than 1100 public health professionals nationwide urging the administration to make climate change a top priority, including, quote, ensuring that the U.S. maximizes reductions in automobile pollution and fuel consumption by setting the strongest possible fuel economy and greenhouse gas standards for automobiles, while encouraging policies and incentives for zero-emission vehicles to fully transition our transportation sector to zero carbon pollution, end quote.

So I think you can see that you have a lot of different constituencies that have your back on accelerating the transition to a zero-emission vehicle future.

Thank you.

MS. DRUFFEL: Good morning, Chair Nichols and

1 Board members and ARB staff. I'm here on behalf of the
2 faith community. I am Allis Druffel, and I work with
3 California Interfaith Power & Light. And I am here for
4 the strong recommendation for the ZEV mandate, for it to
5 be kept as strong as possible.
6 I'd also like to say to the auto industry
7 representatives in this room: Thank you so much for your
8 strides in creating fantastic vehicles that clean our air,
9 save money at the pump, and strengthen our economy.
10 And at the same time, to the industry
11 representatives and ARB: Automakers are challenged to
12 continue their excellent process in creating cleaner
13 vehicles. Do not turn back based on temporary low gas
14 prices. We have to remember why we are here right now.
15 We are here because we are in a planetary crisis. People
16 are actually suffering from multiple illnesses and dying.
17 We have 5200 premature deaths in the South Coast air
18 quality alone due to poor air quality. So we're at a crux
19 here when we recognize that the planet is in crisis and
20 that there are far too many people that are sick and dying
21 from pollution sources.
22 So ARB and industry: We need you really badly
23 right now. You have the technology, the know-how, the
24 committed wonderful workers to make a cleaner California
25 and nation happen.

1 And I'd just like to include that Interfaith
2 Power & Light is in 40 states and the District of
3 Columbia, and we are actively advocating to our members
4 about consumer demand for electric vehicles and for the
5 installation of charging stations.
6 And I have 400 more petitions here in this bag,
7 whoever wants it.
8 So --
9 CHAIR NICHOLS: Give them to the clerk please.
10 MS. DRUFFEL: Okay. Great.
11 Thank you so much.
12 MR. LEWIS: Good morning, Chair Nichols and Board
13 members. My name is Mike Lewis. I'm with Pearson Fuels
14 out of San Diego. Some of you may have heard of us. But
15 a real quick rundown.
16 We started, we built a gas station, a fuel
17 station in San Diego back in 2003, 14 years now. And it
18 had a lot of different alternative fuels, first time in a
19 lot of places. We had biodiesel, we had propane for
20 vehicles, two pressures of natural gas, six electric
21 chargers in E85. The first E85 pump on the West Coast in
22 the United States. And that station struggled very badly
23 for -- in fact, it lost money for seven years in a row.
24 And one of the things that kept us going was that several
25 years into that the Air Resources Board came up with a

1 program to promote alternative fuel infrastructure around
2 the state. And we ultimately got I think $1.3 million to
3 build E85 sites around the state. And then we went on to
4 get funding to build a couple biodiesel terminals. We've
5 helped develop a hydrogen station; I have few more in the
6 works. We got some funding from the Air Resources -- or
7 from California Energy Commission to build more E85 sites.
8 And now we have -- we supply 88 E85 stations around the
9 state of California.
10 And it works. We have major gasoline station
11 chains contacting us. We -- to do E85. We -- the public
12 buys a lot of E85. We have a record number of stations,
13 record number of volume sales almost every month. And
14 it's been very successful. We've opened seven this year
15 already. 2017 we've opened seven, including San
16 Bernardino, Fontana, Fresno, Chula Vista. A lot of these
17 locations are in the -- they score highly on EnviroScreen,
18 as they're supposed to with AB 197. And they don't cost
19 any more, the vehicles don't cost any more, so the
20 consumer doesn't have to pay any more for the vehicles and
21 oftentimes saving money on the fuel.
22 And so what I want to recommend to you is that
23 you reconsider in the midterm review the greenhouse gas
24 conclusions. Because obviously, God knows what the feds
25 are going to do, and you don't want to leave it all in

their hands. And I would suggest to you that the state's invested $15 million building E85 sites. And I thought as a gas station owner I was doing what I was supposed to. Because it was my -- the funding that you guys put there initially that kind of kicked it off. And I'm not asking for any more funding. The E85 industry doesn't need any more funding, and the self-sustainable it has about a 20 percent greenhouse gas reduction. And I'd ask you to keep that midterm review open so that flex fuel vehicles could continue to be incentivized or at least not disincentivized.

Thank you for the time.

MR. LEVIN: Good morning. My name is Joe Levin, and I'm the Executive Director of Plug In America. We're the national voice of the EV driver. And I'm here to make sure that the voices of EV drivers in California, in the other ZEV states, and all over the country are heard in today's discussion.

The basic truth is that electric drive is a better way to move cars around and that people love these cars. They like the way they drive. They like the convenience of being fully fueled each morning and never having to go to the gas station. They like not having to think about maintenance. They like keeping their fuel dollars local, instead of sending them half way around the

1 world. And they like keeping their air clean when they
2 drive.
3 People want to buy these cars.
4 The main complaint that we hear about these cars
5 is that the availability is so limited in much of the
6 country. More than 30 models are now available in
7 California. But in many states you can find only a
8 handful of electric vehicles.
9 We've put on dozens of ride-and-drive events
10 around the country. But outside of California we have a
11 chronic problem of finding enough cars for our events.
12 People show up. They want to test drive EVs. And
13 sometimes there are not enough cars for the demand.
14 People wait around and then after 30 or 45 minutes they
15 give up and they go home. So that's another reason we
16 feel very strongly about keeping the ZEV rule strong.
17 I have in my hand here letters from 88 mayors and
18 city council members from most of the major cities in the
19 other ZEV states. Because we have a short time, I won't
20 list all the cities, but there's 88 cities. And I also
21 have letters from 32 different state legislators from all
22 of those states. These have all been submitted already
23 into the record.
24 And these are people that represent literally
25 millions of their constituents that are asking for a

1 stronger ZEV -- a strong ZEV rule that will put more
2 electric vehicles on the streets of their cities and make
3 them more available for their constituents so they can buy
4 or lease them.
5 So I'm happy to make sure that their voices are
6 heard here today. And I want to support the staff
7 recommendations. I hope that you do as well, and make
8 sure that these cars are available for people to purchase
9 everywhere.
10 Thank you.
11 MS. PIERCE: Good morning, Chair Nichols and
12 members of the Board. I'm a member of an EV club, the
13 Electric Vehicle Association of Southern California. When
14 I moved to Orange County from out of state in the late
15 spring 1979, I kept getting lost on the freeways. Friends
16 kept telling me to get my bearings; remember, the
17 mountains are to the north. I kept looking at them.
18 Mountains? What mountains?
19 About eight months later, after some heavy rain,
20 I finally saw the mountains. They were beautiful.
21 The smog was always so bad back then, the
22 mountains were hardly ever visible. Thanks in part to
23 emission restrictions, that is no longer the case.
24 In 1989, I moved to the Inland Empire with my
25 youngest -- when my youngest daughter was less than a year

1 old. I felt a lot of guilt for that move when she
2 developed asthma. We could liter -- from where we lived,
3 we could literally watch as the smog rolled in from L.A.
4 throughout the day.
5 My older girls in school had to forego outside
6 activities on those smog days when the air was deemed
7 unhealthy. It happened a lot when they were younger. But
8 as the years progressed, it happened less frequently.
9 We all know that the Southern California region
10 has some of the worst traffic congestion in the country.
11 The emissions from all that traffic causes so much health
12 problems to everyone. Placing restrictions on emissions
13 reduces the brown air and the health problems.
14 The easiest way to reduce emissions is to
15 drive -- the easiest way to reduce emissions is to drive
16 zero-emission vehicles. The requirements that California
17 has developed over the years to ensure reduced emissions
18 has had a positive effect not only in California, but
19 across the country and even the world. More countries are
20 developing zero-emission vehicle requirements due to the
21 advances in technology developed because what California
22 started.
23 Please do not regress in this fight. If
24 zero-emission policy is abandoned, or emission
25 requirements are relax, the air will once again be brown

every day and overall health of residents will decline. If we lose site of California's zero-emission goals, we will also fall behind in technological advancements that countries like China are developing.

I drive a 2012 Leaf -- Nissan Leaf and it's so fun to drive. It is quiet and fast off from the stop. When I first got my car, there were not a lot of choices. Thanks to all the progressive California rules, there are many zero-emission vehicles available now and more developed all the time. Please keep moving forward. Don't go backwards.

Thank you.

(Applause.)

CHAIR NICHOLS: Thank you.

DR. REICHMUTH: Chair Nichols and members of the Board. My name is David Reichmuth and I'm speaking on behalf of the Union of Concerned Scientists. And thank you for taking the time today to listen to myself and all the other stakeholders that have come here today.

I'd also like to thank staff for their work on the midterm review. It's a comprehensive document. It's technically sound, and it will serve you well as you make this decision on how to proceed with the ZEV regulations.

We support the staff's recommendations in the midterm review to remain -- to keep the Advanced Clean Car

1 Program as is through 2025. We submitted detailed
2 comments on this, so I just want to hit just one or two
3 items to pull out from those comments.
4 Staff recommends making no changes to the ZEV
5 Program in California and the 177 states. We agree. The
6 ZEV Program has been successful in bringing zero-emission
7 vehicles to the state and giving many Californians the
8 option to buy a cleaner and, frankly, better alternative
9 to a gasoline vehicle.
10 Now, in the comments submitted some of the
11 automakers have suggested that changes are needed to the
12 program especially regarding implementation in the 177
13 states. They point to the lower sales in the East Coast
14 177 states as compared to California, showing the
15 inability to sell these ZEVs on the East Coast. This
16 ignores several important factors under the control of
17 automakers, the most important being ZEV model
18 availability and ZEV inventory availability.
19 In part due to the travel provision as we heard
20 from the representative from Massachusetts, some
21 automakers have not sold certain ZEVs on the East Coast.
22 One example is the Fiat 500E BEV, which is available only
23 in California and Oregon, despite the fact that it's sold
24 over 5,000 units here in California the last three years.
25 Other models have substantially lower inventory

1 available. So they're technically available in the 177
2 states on the East Coast, but functionally they're
3 unavailable.
4 We at UCS did a study on this issue. We found
5 that when you looked at the availability in different
6 cities, there are stark differences. In Boston there's
7 about 90 percent fewer ZEVs on average available than in
8 the Oakland Bay Area.
9 And that is includ -- that's -- that holds even
10 when you take into account the differences in vehicle
11 ownership between these cities.
12 Simply put, car buyers can't buy cars that aren't
13 there, and they won't consider those that they can't see
14 and test drive at dealerships.
15 Now, we also agreed that staff -- that ARB should
16 ask staff to begin the process of developing ACC standards
17 for post 2025. We know that we're making progress in
18 reducing emissions, improving air quality. But that
19 progress needs to not just continue, but it needs to
20 accelerate after 2025.
21 California has clear targets for lower emissions,
22 and the ARB should start the work of bringing all
23 stakeholders into the process of designing policies to
24 achieve those goals.
25 Thank you.

1 CHAIR NICHOLS: Thanks.
2 MS. HEARTQUIST: Hello. My name is Christina
3 Heartquist, and I'm speaking today on behalf of Jack
4 Gillis, auto expert and author of the Car Book, and Mark
5 Cooper, Director of Research, both of the Consumer
6 Federation of America, a national association of over 250
7 nonprofit organizations working to advance the interests
8 of American consumers.
9 For consumers, California's Clean Cars Program
10 saves money and strengthens local economies. So the Trump
11 Administration's decision to rescind EPA's final
12 determination on fuel economy standards makes California's
13 clean car leadership more important than ever. The work
14 you do is federalism at its best.
15 California's current standards are anchored in a
16 joint agreement reached by automakers, Washington, and
17 Sacramento; and CFA urges CARB to stay the course.
18 Because 12 other states and the District of Columbia have
19 adopted California's standards, your decision today will
20 affect whether 113 million Americans will be able to buy
21 cleaner cars, save money at the pump, and breathe cleaner
22 air.
23 Most importantly, consumers strongly support what
24 CARB has been able to accomplish. At CFA our polling
25 consistently shows that the overwhelming majority of

1 Americans - Republicans and Democrats - from the nation's
2 heartland to the coasts - supports making cars run on less
3 gas and pollution because it drives savers money -- it
4 saves drivers money.
5 Under the Clean Air Act, California and the other
6 clean car states have the right to set their own standards
7 and protect their own air quality. This is an important
8 right, has been recognized for decades, and has been
9 protecting both lungs and pocketbooks ever since.
10 These 13 states and the District of Columbia
11 represent some of the most vibrant economies in the
12 country. When consumers can spend less on gas, they spend
13 more on local goods and services. This builds the economy
14 and communities across the nation instead of exporting
15 money to out-of-state and foreign oil interests. Clean
16 car standards have generated economic growth in jobs
17 across the nation by spurring the development and
18 manufacture of advanced efficiency technologies, and
19 California's zero-emission vehicle program has driven
20 development of some of the cleanest cars on the planet.
21 For consumers, ZEV makes it possible to disengage
22 entirely from the volatile oil market and avoid stopping
23 at the gas station ever again.
24 Years of analysis and input from automakers,
25 advocates in governments, and other stakeholders have

1 shown that current clean car standards are achievable and
2 cost effective for automakers and consumers. Our work at
3 CFA backs up these findings.
4 We have exhaustively studied the economics of
5 clean cars and there is absolutely no question that from
6 the perspective of individuals, families, and businesses
7 that buy or lease, car owners benefit from the minute they
8 drive off the lot.
9 As we'll clearly demonstrate in our written
10 testimony, robust clean vehicle standards are good for
11 consumers. Without strong state leadership from
12 California and the states that have adopted CARB
13 standards, consumers will be saddled with less efficient,
14 more costly, and greater polluting cars and trucks. With
15 California's leadership, these 113 million Americans will
16 save gas, money, breathe better air, and have access to a
17 broad array of cleaner, more efficient vehicles.
18 On behalf of consumers across America, the
19 Consumer Federation of America urges CARB to stay the
20 course.
21 CHAIR NICHOLS: Thank you.
22 MS. MOELLER: Good morning. My name is Jennifer
23 Moeller, and I come before you today as a mother on behalf
24 of Moms Clean Air Force and a concerned citizen.
25 When it comes to caring for my children from a

1 mother's perspective, there is nothing more important than
2 health and safety. As a mom living in Los Angeles, health
3 issues stemming from air pollution is very concerning.
4 The traffic congestion and smog is a large
5 ongoing problem for many of us moms as we run our kids
6 from one activity to another. In fact, all drivers are
7 impacted by both the heartache and headaches of sitting in
8 traffic for prolonged periods of time and taking in all
9 that unnecessary smog into our lungs.
10 For children, this is especially concerning, as
11 it impacts those young developing lungs and bodies even
12 more. This is why I am here today, to urge you as
13 California's leadership council to act on moving forward
14 with the California Advanced Clean Cars Program, and
15 here's why:
16 California has led the way on clean air policies,
17 making it the first state to develop a regional air
18 pollution control district in 1947 to address the many
19 ongoing crucial and health affecting air quality problems
20 in Los Angeles.
21 Congress subsequently adopted a new provision of
22 the CAA section 177 allowing other states to opt into
23 California's vehicle emission standards, which means a
24 large number of states have opted into California's
25 standards over the years, and since then 12 have opted

1 into our LEV and ZEV standards, overall representing 35
2 percent of cars sold in the U.S.
3 Mainly California's economy has grown
4 simultaneously as the state's leader in harmful-emissions
5 reduction. Of California's 19 areas that once exceeded
6 either the one-hour or original eight-hour ozone
7 standards, only four still exceed those standards today.
8 Even the South Coast and San Joaquin Valley, two
9 areas of the state that face the nation's most critical
10 air quality challenges, have seen significant progress.
11 Clean air progress in California has occurred at
12 the same time the state population has increased by over
13 25 percent and the economy has continued to grow.
14 California is the world's sixth largest economy,
15 and the job growth in the state has outpaced the national
16 rate, all while adopting the nation's most protected air
17 quality policies.
18 I am the mother of three beautiful children under
19 the ages of 6. So when it comes to health and the
20 environment, I can't stress enough how passionate I am
21 about clean air, which means standing for zero-emission
22 vehicles and a Clean Cars Program to support it.
23 This not only benefits our state as a whole but
24 our environment by making a significant cut into our smog,
25 lessening asthmatic resulting health diagnoses in our

1 children, and creating a longer lasting planet for our
2 future. Lets work together to make a difference, not just
3 for us, but for our children.
4 Thank you, Board members, for your time and
5 consideration.
6 CHAIR NICHOLS: Thank you for being here.
7 I'm a fan of yours on social media. I follow
8 you.
9 (Laughter.)
10 CHAIR NICHOLS: Okay. I think we should -- I'm
11 sorry because you just got up here. Maybe we'll want to
12 take one more witness. But we've been going since 8:45.
13 Our court reporter hasn't had a break, and I think we want
14 to continue this item through to the final conclusion
15 before we break for lunch, and then break for lunch.
16 So let's take a 10-minute break, 10-minute break.
17 Will you be okay with that?
18 All right. We'll bring you back up in 10 minutes
19 then. Thank you.
20 (Off record: 11:59 a.m.)
21 (Thereupon a recess was taken.)
22 (On record: to 12:15 p.m.)
23 CHAIR NICHOLS: All right, everybody, please
24 settle down.
25 We want quiet for our witness.

1 Okay.
2 MS. HERZOG: Should I go ahead?
3 CHAIR NICHOLS: Yes, Ms. Herzog, you can go
4 ahead.
5 MS. HERZOG: Thank you.
6 Good afternoon. My name is Megan Herzog. I'm an
7 attorney at the Conservation Law Foundation, or CLF.
8 Founded in 1966, CLF is a member-supported nonprofit that
9 uses law, science, and economics to tackle the
10 environmental problems that threaten New England. We work
11 in five ZEV states - Massachusetts, Vermont, Maine, Rhode
12 Island, and Connecticut.
13 I traveled all the way from Boston to represent a
14 broad coalition of ZEV state environmental advocates and
15 residents who strongly support the ZEV Program. I have
16 here more than 700 letters from people who want more EVs
17 to be sold in New England.
18 I also bring a letter signed by 34 public
19 interest organizations that are actively promoting ZEVs in
20 the northeast and the mid-Atlantic.
21 Our organizations have helped achieve a number of
22 major successes in our states, including rebate and grant
23 programs for EVs, multiple new statutes and utility
24 commission policies, and thriving public education
25 programs.

1 These initiatives and many others are driving
2 increased adoption and awareness of EVs in our region.
3 And we are committed to advocate for further progress, but
4 we need your help.
5 Transportation is our region's single largest
6 source of greenhouse gas emissions. And they are critical
7 to meeting our ambitious climate requirements as the ZEV
8 program. For instance, Massachusetts Global Warming
9 Solutions Act requires emissions reductions of 25 percent
10 below 1990 levels by 2020, and 80 by '50. Vermont is even
11 striving for 95 by '50. Our states may be smaller but we
12 have mighty goals, and we will not submit to false claims
13 by industry. We want to drive electric.
14 Rhode Island, which is roughly the size of
15 Yosemite Park --
16 (Laughter.)
17 MS. HERZOG: -- nonetheless offers $2500 in a
18 rebate for an EV purchase.
19 Connecticut has a population on par with Fresno
20 County, but boasts nearly 350 EV charging stations.
21 And in Massachusetts, which is comparable to the
22 Bay Area, utilities are pursuing $70 million worth of
23 investments in EV infrastructure.
24 Section 177 states are proud to stand with
25 Californians as clean energy leaders, and we thank the

1 Board for all that you've done to advance the EV
2 marketplace in our states.
3 We will continue to defend our states' rights to
4 regulate climate pollution and air quality and to defend
5 public health in our states. And we urge you to move our
6 shared legacy forward and stay firm on your commitment to
7 strong clean car standards for our states.
8 We look forward to continuing to support
9 implementation of the ZEV Program.
10 Thank you.
11 CHAIR NICHOLS: Yes, go ahead, Ms. Riordan.
12 Wait just a second, if you would.
13 BOARD MEMBER RIORDAN: I just have a quick
14 question. And, that is, in your states, do you find it
15 difficult to find an EV to try out and to use? Is that a
16 problem for your states or not? Are they plentiful or
17 not?
18 MR. HERZOG: No, it's absolutely a problem, as I
19 believe you heard from other testifiers before. There
20 have been studies where folks have gone to dealerships in
21 attempts to drive EVs and often they're not charged or
22 they're not available or they're models that just aren't
23 sold in our states.
24 And so I think these letters show that people
25 want more EVs. We'd love to have the option.

1 BOARD MEMBER RIORDAN: Have you followed up at
2 all with the dealers to inquire why more aren't available?
3 MS. HERZOG: We do engage in a lot of dialog with
4 the dealers, and we're continuing to work with them. But
5 I think the ZEV Program regulations and end of "travel"
6 will be essential to getting more cars on our states.
7 BOARD MEMBER RIORDAN: Thank you.
8 MS. HERZOG: Thank you.
9 CHAIR NICHOLS: Supervisor Serna, did you have --
10 oh, no. Sorry.
11 All right. Go ahead.
12 (Laughter.)
13 CHAIR NICHOLS: I wanted to take this moment
14 because I hadn't had a chance earlier to introduce our
15 newest member of our senior executive team at ARB, who
16 happens to be from -- most recently from Massachusetts and
17 from your organization, where she became known nationally
18 as a leader in the environmental justice community. And
19 she is now our assistant executive officer for
20 environmental justice. And she's standing right there to
21 wave to everybody.
22 Veronica Eady.
23 Veronica.
24 (Applause.)
25 CHAIR NICHOLS: Welcome. It's just -- it's

1 really great to have -- Veronica, to have this new
2 position, and to have her here when we're considering
3 these issues which are so important to all of us.
4 So thank you for giving me the opportunity to
5 piggyback.
6 MS. HERZOG: Thank you.
7 MS. SMART: Hi, Chairwoman Nichols and members of
8 the Board and CARB staff. My name is Anne Smart and I'm
9 the Vice President of Public Policy for Charge Point.
10 We're the largest network of EV charging stations in the
11 world. Right now we have more than 18,450 charging ports
12 here in California and 33,000 across the country.
13 I'm here today to congratulate staff on a great
14 report, and continue to support our current path towards
15 2025. For us in the charging station industry, it's
16 really important that we have this regulatory certainty.
17 It helps us know what the projections are going to be for
18 EV sales, helps us size our own investments, helps us
19 figure out range on our technology. It really helps to
20 make sure that we have our own consistent market along
21 with the EVs that are out there.
22 In addition to continuing on the current path, we
23 also want to make sure that we continue to get rid of the
24 "travel" provision for BEVs. For us it is also important
25 that we move forward with getting as many EVs as possible

in the non-California ZEV states. We're doing our part to put infrastructure there, it has been said by several people. But demand for EVs help drives demand for charging stations. And though it is a chicken-and-egg issue, if we can get more cars and dealerships there, we can also get more charging stations in the ground.

Beyond 2025, Charge Point supports creating an additional goal along the lines of what staff recommended. However, we encourage that as this new regulation is developed, that CARB work with automakers, charging infrastructure providers, and other stakeholders to set this goal so that it's both ambitious yet achievable beyond 2025.

Aligned with that we also think it would be important if this state were to set a charging station goal. I have put this in writing a few times now. But I do think that as we are figuring out how much charging infrastructure we need to support these vehicles, that you have a number in mind or at least a goal or a target. I've suggested based on NREL numbers a goal of one public charging station for every five electric vehicles - NREL is the National Renewable Energy Laboratory - that we should have a goal of one public charging station for every five electric vehicles on the road. That would include level 2 and DC fast chargers. Or in order to make

1 sure that our charging stations are located throughout the
2 state, it's not just in coastal areas, perhaps a goal per
3 mile of one charging station every 30 miles might be a
4 more appropriate goal to set.
5 But as we're looking for what happens beyond
6 2025, it would be great to work with CARB to set some sort
7 of charging station goals so that we're all on the same
8 page as to how many charging stations we need and whether
9 or not we're there or falling behind.
10 Lastly, for us we think it's incredibly important
11 that we continue to support ZEV adoption in disadvantaged
12 communities. For the charging station industry, it's
13 really important that we also have vehicles in those
14 communities that we're working to get more investments
15 there. And we look forward to working with CARB to make
16 sure that happens.
17 Thank you.
18 MR. WUNDER: Chair Nichols, members of the Board,
19 my name is Andy Wunder. I'm the manager in CERES
20 California program. CERES is a nonprofit organization
21 advocating for sustainability leadership. We mobilize a
22 network of 39 leading U.S. companies representing over
23 $400 billion in annual revenue. These companies are
24 committed to advocating for the adoption of meaningful
25 energy and climate policy. This group is called BICEP,

1 Business for Innovative Climate and Energy Policy. This
2 group includes many California-based companies such as
3 Levi Strauss, eBay, and Dignity Health.
4 I am here on behalf of BICEP to show business
5 support for Air Resources Board staff recommendations
6 detailed in the summary report for the Advanced Clean Car
7 Review -- Midterm Review.
8 I'd also like to strongly voice BICEP's support
9 for California's authority to adopt and implement its
10 advanced clean car regulations. Regarding greenhouse gas
11 emission standards, we support continuing California's
12 participation in the national program.
13 However, if EPA's greenhouse gas standards are
14 significantly weakened, we urge ARB to assess the need to
15 adopt new stronger standards. Strong standards provide
16 critical reductions in greenhouse gas emissions needed to
17 ensure California meets its 2030 climate goals. Strong
18 standards benefit consumers, businesses, and the economy,
19 as money saved on gas is diverted to consumer spending.
20 And strong standards drive innovation and investments in
21 advanced vehicle technology necessary to keep American
22 companies competitive in the global economy.
23 Regarding California's Zero-emission Vehicle
24 Program, we support staff recommendations to strengthen
25 the ZEV Program post 2025 to ensure the program meets its

1 intended goals. Reaching these goals are key to
2 California's meeting its clean air and climate and public
3 health goals.
4 In addition to reducing environmental public
5 health impacts, a strengthened ZEV Program provides key
6 bottom-line business benefits. The ZEV Program is
7 creating a robust market and reducing ZEV purchase costs
8 for corporate fleets. This helps fleet managers
9 transition to cheaper-to-fuel electric vehicles and avoid
10 petroleum fuel price volatility.
11 Regarding particulate matter emission standards,
12 we support maintaining the stringency of the 1 milligram
13 per mile particulate matter 2025 emissions standard. This
14 drives strong climate health benefits and will ensure
15 healthcare cost savings and increase productivity in
16 California's economy.
17 In summary, BICEP strongly supports ARB staff
18 recommendations to maintain the Advanced Clean Cars
19 Program as outlined.
20 Thank you very much for your time.
21 MR. SHEARS: Good afternoon, Chair Nichols and
22 members of the Board. My name's John Shears. I'm with
23 the Center for Energy Efficiency and Renewable
24 Technologies, here to strongly endorse the recommendations
25 of the staff and to encourage you to accept those

1 recommendations and to move forward.
2 I'm one of the NGO folks who has worked most
3 closely with the El Monte staff. And I want to
4 congratulate and thank the El Monte staff as well as the
5 rest of the crew for the fine work that they've been doing
6 just to keep tabs on things and making sure that we can
7 indeed move forward with this program.
8 I wanted to also sort of step back out of the
9 bubble for a second and take note. I think it was Mr.
10 Bozzella earlier this morning who said that this program's
11 too aggressive. I'd like to remind everyone that in the
12 Arctic this year, the average temperatures were 20 degrees
13 warmer than ever before; in the winter, 20 degrees warmer
14 in the Arctic. There are some climate scientists who are
15 now predicting that the Arctic could end up being ice free
16 year-round. That has serious implications for the global
17 atmospheric wind systems and how they link to the current
18 systems.
19 California's climate is one of the most
20 vulnerable climates to the effects on the planet's winds
21 and ocean currents.
22 This program, which started as California's first
23 climate program is critical to helping us and the rest of
24 the world through California's leadership move forward to
25 deal with climate change. And as we saw yesterday with

1 some of the other provisions that the Board has adopted,
2 California is not just picking on the auto industry.
3 California is doing everything it can to address climate
4 change.
5 Another aspect of all of this of course is -- are
6 the state SIPs. Something else that was considered
7 yesterday. And the work in the vision process that Joshua
8 Cunningham and other folks led up with the CARB staff, if
9 California doesn't move forward with programs like this
10 program, we are at greater and greater risk of not only
11 not being able to address climate change in the way we
12 need to, but also getting into violation of the state SIPs
13 and running afoul of the federal government in that
14 manner.
15 So there's the paradox here of if we pull back on
16 this, we risk running into other violations with the
17 federal regulators.
18 So I encourage you to move forward and to also
19 consider dropping the USO 6 limit based on further
20 development through El Monte.
21 So thanks.
22 DR. JACPOR: Good afternoon, Honorable Chair
23 Nichols and Honorable Board members. My name is Dr. Karen
24 Jacpor, and I'm here today as a representative of the
25 American Lung Association as a doctor for climate health,

as a patient, and as a parent here in the Inland Empire.

I've been fighting severe asthma and I've been hospitalized or admitted to the emergency room so many times, I have lost count. At least over 40. And so I know firsthand how important it is the work of the clean air programs, and I really applaud the work of the California Air Resources Board.

Sometimes I feel like a canary in a coal mine when I notice that my breathing is worse when the air quality index worsens. My daughter is unable to play outdoors about 100 days a year because I can't supervise her outdoors on unhealthful air days.

Each year, 15 billion in health and climate damages are caused by passenger vehicles in California, according to the Lung Association report issued last year. But health impacts can be reduced by 80 percent by 2050 through strong zero-emission vehicle policies. The bottom line is that zero-emission vehicles can save lives with this 80 percent reduction in health consequences.

I am very privileged to show you today that there is broad public health support. I have two letters. This letter represents 300 professionals -- health professionals from across the country; and this letter represents 28 health -- leading health organizations in California. And this -- among these 28 health groups

1 include the California Medical Association, the American
2 Academy of Pediatrics, and the California Academy of
3 Family Physicians, and we're calling for California to
4 keep us on the right path.
5 Our letters states that clean car programs are
6 working as planned to reduce emissions and that the Board
7 should start now to develop the next generation of clean
8 vehicle standards. We believe that California's authority
9 to develop stronger than federal standards is critical to
10 protecting the health of vulnerable communities, including
11 the residents of this region that face high ozone levels.
12 California's standards should be implemented and
13 maintained, and California's authority must be preserved.
14 This is first and foremost a public health issue for all
15 Americans.
16 Thank you for your work on the review, on
17 developing and implementing the programs that I need to
18 breathe today, and so that our kids will grow up in air
19 that won't put them at risk of a permanent lung health
20 deficit for life.
21 Thank you very much.
22 MR. MAGAVERN: I'm Bill Magavern with the
23 Coalition for Clean Air. And I've been working on clean
24 car issues since the late '80s when I was one of Nader's
25 Raiders in Washington D.C. So I've had my share of

1 tangles with the big auto company.
2 But I've also for the last three years been happy
3 to be the owner of a General Motors car, a Chevrolet Volt,
4 which as you know is a breakthrough plug-in hybrid. And I
5 say that because I do believe that the big auto companies
6 can transform themselves and become part of the solution
7 instead of part of the problem and they can be drivers of
8 change and social responsibility.
9 But they're only going to do that if you tell
10 them to, because we've seen historically, whether we're
11 talking about fuel efficiency or catalytic converters or
12 seat belts or airbags, that those innovations get put on
13 the cars when government requires it.
14 And we now have the federal government going in
15 the wrong direction, so it really falls to this body to
16 keep us moving forward.
17 And the auto companies lament a lack of consumer
18 acceptance. But we know that they spend billions of
19 dollars to shake consumer desires. And you've already
20 heard this morning that they're not spending those
21 billions to get people to want to buy ZEVs. And that
22 needs to change.
23 They also need to do a better job of motivating
24 the dealers. And the study by Sierra Club confirms the
25 experience of so many EV shoppers who have found that the

1 dealers are not interested in or not prepared to sell them
2 electric vehicles.
3 This is of course an issue where California plays
4 a really important role nationally because of our unique
5 authority under the Clean Air Act. It's also about
6 protecting the health of Californians.
7 And we support all of the staff recommendations.
8 I want to particularly call attention to the importance of
9 maintaining the particulate matter standards. You have
10 our letter on that. And we also support strengthening
11 that standard over time because, as you've heard, the
12 European Union already has a tighter standard.
13 We also applaud the staff's intent to explore
14 broadening the ZEV standard. And we're particularly
15 interested in the possibility of including heavy-duty
16 vehicles because, as we discussed yesterday, we really
17 need to go zero emission in the heavy-duty sector in order
18 to attain both our air quality and our climate standards.
19 Thank you very much.
20 MS. McGHEE: Good afternoon. My name's Lisa, and
21 I'm with the San Diego Airport Parking Company. And it is
22 a pleasure to be able to see the opportunities that have
23 been a part of clean transportation. And it's kind of
24 perfect that I got to follow Bill because he kind of just
25 allowed me to lead into some opportunities that I wanted

1 to speak about today.
2 Moving forward really is about adoption, and
3 relating to SB 350. And we need to drive zero-emission
4 vehicles. And who we are targeting is a big part of how
5 we maybe can accelerate adoption. It's not just about
6 light duty. If you look at your own model in table 15, it
7 shows that your vans and your trucks have no ZEVs.
8 There's actually only one zero-emission van today in the
9 entire nation. I speak to you because that is the type of
10 vehicle that we drive. It's a passenger vehicle. It's
11 also for personal use. So I do think there's a great
12 opportunity to create OEMs -- branded OEMs to help reduce
13 this gap of inventory that simply just isn't available.
14 I have driven in one-year's time 125,000 miles in
15 a ZEV. So there's a lot of pluses and benefits for a ZEV.
16 And there's also many barriers.
17 And so adoption is a big part of how we can
18 continue to move the SB 350 forward, and we need inventory
19 to do that.
20 Airports is what I wanted to talk about. I'm an
21 off airport parking operator. We have 350 shuttle vans in
22 San Diego. We average 50- to 100,000 miles per year.
23 That's 17 million miles in a year. We would gladly find
24 the ZEV use to be exceptional for our type of sector.
25 It's short haul. We're in -- in a controlled environment.

1 So there's a lot of pluses that I think that could be
2 considered when you target how you can accelerate
3 adoption.
4 Moving into efficiencies. We're lacking some
5 standards on efficiency. And what I want to bring up is,
6 what is a kilowatt hour in miles? You know, we don't
7 really have a standard right now. So how are we going to
8 compare fuel regulation standards in ICE vehicles to an
9 electric vehicle? That's an important element that's
10 missing right now. We do not know how many miles is a
11 kilowatt hour, and we're not having any regulation for it.
12 Also considering there's multiple exemptions
13 associated with certification that -- are other things
14 that can be considered when we talk about durability,
15 useful life. There is no requirement for garage services
16 right now for a ZEV OEM. That's created an obstacle for
17 me.
18 And so I would suggest that if we can continue to
19 try to help move the space forward that we have some more
20 regulations to support the space for adoption.
21 Thank you.
22 MS. REINHARDT: Good morning. My name is Alisa
23 Reinhardt and I'm the Director of Regulatory Affairs for
24 the California New Car Dealers Association.
25 California's new car dealers support the findings

of your midterm review. We especially found the CARB staff's discussion around the state of the ZEV market and the current levels of consumer demand very thoughtfully done, and want to reiterate what we said in our written comments to the Board.

We maintain that every new car sold that replaces an older, higher polluting car means cleaner air and safer roads, and our state's dealers are ready and willing to partner with you to help put more zero-emission vehicles and hybrid vehicles on our roads.

Automakers have done a fantastic job introducing a wide variety of exciting new vehicle options in this space. And California dealers will gladly sell any one of these cars to anyone walking into a dealership that is qualified to buy one.

Any stories you may hear to the contrary are anecdotal at best, and are simply not representative of California's dealer body as a whole and are support for your efforts.

Thank you.

REV. KOTEEN: Good afternoon. A fellow Unitarian once wrote in a cartoon that people of a limited intelligence are drawn to meetings like moths to a porch light.

(Laughter.)

1 REV. KOTEEN: He presumed that it was -- that
2 they had a very large bladder-to-brain ratio --
3 (Laughter.)
4 REV. KOTEEN: -- and managed to sit for a long
5 time and wear everybody else out.
6 But after sitting here yesterday for several
7 hours, I decided that it really takes buttocks of steel --
8 (Laughter.)
9 REV. KOTEEN: -- and a very stiff spine. And I
10 therefore honor you for having that capacity.
11 (Laughter.)
12 REV. KOTEEN: I hope your chairs are more
13 comfortable than the ones in the audience.
14 (Laughter.)
15 REV. KOTEEN: When I was thinking about yesterday
16 and today, the phrase that came to mind was from Exodus,
17 and it was about hardening Pharaoh's heart. And it didn't
18 seem fair to me when I read that that God not only
19 punished the Egyptian's but he also hardened Pharaoh's
20 heart so that Pharaoh wouldn't release the Israelites.
21 But I realized, first of all, that I was guilty
22 of what religious liberals always claim of conservatives,
23 which is that I was being guilty of misplaced literalism.
24 But, secondly, it was an acknowledgement that Pharaoh
25 could not be Pharaoh without a hard heart, and he could

1 not be willing to give up his slaves.
2 And we have all become slaves to the fossil fuel
3 industry. Not just you, but me, and everyone else.
4 And I'm wondering when we're going to start
5 treating tailpipes the way we treat cigarettes. I
6 remember when I could smoke anywhere I wanted to,
7 including an airline, and even in some places -- movie
8 theaters and restaurants. You can imagine what effect
9 that secondhand smoke had on people who weren't smoking.
10 And yet right now we still have tailpipes that
11 spew the same kind of poisons. And I'm in support of what
12 you're doing today, but we all need to do more.
13 So yesterday's testimony, particularly by the two
14 members who are physicians, about how painful it was not
15 only to see that -- the testimony people who have already
16 had relatives that are dying, but people who are in the
17 process of dying right now as a consequence of this,
18 brings us to mind that whatever we're doing now, we're
19 called upon to do more.
20 Thank you for your time.
21 MR. SCOTT: Good afternoon, Chair Nichols and
22 Board members. My name is Craig Scott from Toyota's
23 advanced technology group. And I'm proud to tell you
24 today that in the last year Toyota has sold nearly 1500
25 Mirai fuel cell vehicles and we're well on our way to

1 reaching our first milestone of 3,000 by the end of next
2 model year.
3 That said, a meaningful expansion of sales to
4 achieve our shared goal of reduced greenhouse gas
5 emissions in the transportation sector will require
6 growing hydrogen infrastructure both in number and
7 capacity.
8 Because we recognize the importance of helping
9 guide the development of infrastructure, Toyota has taken
10 the unusual step of getting involved by providing both
11 financial and technical assistance, initially by building
12 stations at three University of California locations,
13 followed by helping to start first element in California,
14 and then a network of 12 stations in the Northeast.
15 Finally this year we were proud to participate in
16 the groundbreaking Energy Commission award to Shell, the
17 first network of hydrogen stations in the U.S. to be built
18 by a major energy company.
19 Similar to our vehicle rollout efforts, we
20 believe it is necessary to accelerate the 100 goal from
21 2024 to 2020. Considering the amount of time it takes to
22 site, permit, and build locations, the time is upon us to
23 decide how the State can support a network beyond 100. We
24 currently estimate the need is around 225 sites by 2025,
25 and we must also include the other ZEV states. Reducing

1 emissions is our shared goal, and to be effective, we need
2 to sell fuel cell vehicles across all locations.
3 So far in the Northeast the only hydrogen station
4 network project to be funded is the one by Toyota and Air
5 Liquide .
6 As we move beyond the first 50 funded stations we
7 would continue to request the state's support to improve
8 the allocation of AB 8 funds. Namely, the following are
9 specific requests. Customer needs and preferences must
10 play the primary role in selecting site locations. Both
11 coverage and capacity are of key importance. Three
12 stations in close proximity are needed for a gasoline-like
13 experience. The station capacity must grow by a factor of
14 3 to 4 times. Local communities and property owners must
15 be incentivized to help drive this effort. Station
16 project applicants must demonstrate control of the site
17 before being awarded funds. And grant awardees need to be
18 incentivized to complete the project within a 12- to
19 18-month time frame or be subject to funding termination
20 and reassignment.
21 My last comment for today involves the price of
22 hydrogen at the pump and the very serious and immediate
23 need to find a pathway to reduce it substantially.
24 In addition to the financial support in
25 developing stations, Toyota has also provided $15,000 in

1 complimentary fuel to each Mirai customer to show our
2 appreciation, but to also insulate them from the gap in
3 prices. To gain widespread market acceptance, an
4 incentive mechanism to reduce the price and make it closer
5 to gasoline parity is necessary. We believe the cost must
6 fall far below the $11 per kilogram mentioned in the MTR
7 report. And in fact in Japan the target is 8.75, where
8 natural gas as you know is far more expensive than here.
9 We believe a reasonable and achievable target for
10 California is 5.50 to $6 per kilogram.
11 Toyota remains committed to helping the State and
12 it's stakeholders.
13 And we thank you for your time today.
14 MR. EDER: Good afternoon, Board. I'm Harvey
15 Eder. I'm speaking for myself and for the Public Solar
16 Power Coalition.
17 I want to incorporate into the record here the
18 record from the 2016 AQMP, the environmental document
19 associate economic document. And in that, there's
20 information about equity -- I want to talk to you about
21 solar equity and environmental justice low income people.
22 There's a -- a book called "The Capital in the
23 21st Century" about equity by a French economist that's in
24 the record, and saying how inequity in our society is
25 increasing. And there's also discussions that have been

1 had with the senior staff vis-a-vis the Board that we've
2 participated in. We've proposed 10 million low- and
3 middle-income electric vehicles and another from 250,000
4 to a million trucks, solar electric either batteries or
5 hydrogen fuel cells.
6 We're looking at models of -- trying to get
7 equity to low income people as well as just the
8 corporations and whatnot, upper income people that take
9 the tax credits and write-offs. And so we think this is
10 important.
11 Solar elect -- nothing has been said about where
12 the electric comes from. It's got to come from solar.
13 Fifteen years ago you had folks coming here, said we've
14 got solar electric. Paul Scott, et cetera. And that's --
15 I mean, you know, it can't be from natural gas, from
16 fossil fuels, or nuke. There's still 600 megawatts of
17 nukes coming from Palo Verde vis- à-vis Edison, and more
18 from some of the local public power here that extend to
19 the power lines.
20 Anyway, this needs to be looked at. Solar has
21 come down and is coming down. We're looking at robotics,
22 artificial intelligence. There was an article in the
23 Times how they're going to use robots to prune in the
24 Central Valley and up in Napa. And this is -- the
25 difference between regulation and automation -- and this

is -- we got to look at the biggest picture in society and look at what's happening with equity and who's going to own and control these things. And this needs to be done now. We're looking at the public-private partnership.

Also there's the book that was incorporated into the record, "This Changes Everything," by Naomi Klein, with 350. This does change everything. Included in the record is the information on 750 to 800 parts per million CO2 equivalent. We can't just use CO2 anymore.

And anyway, thank you.

MR. WHITE: Madam Chair and Board members. I'm John white. I'm happy to be representing the Center for Energy Efficiency and Renewable Technologies this afternoon and also the Hydrogen Business Council.

Couple of thoughts that come to mind. I was with the Board and in the audience in 1990 when the original ZEV mandate was adopted. And I also go back a little further to when we were discussing the feasibility of the 3-way catalysts. And one of the uniform things we learned is that what we think it's going to cost turns out to not be what it actually costs because we put our minds together we get scale and we work together.

I want to compliment the staff and the Board for, first of all, really good hearing and lots of good contributions. Important technical work that our friends

1 at EDF and ICCT gives us confidence that we can do this.
2 And I think also the fact that the State of
3 California and -- is stepping up with a significant
4 integrated program of incentives for infrastructure as
5 well as to assist in buying the vehicles. Bodes well for
6 our success.
7 But there are dark clouds on the horizon. I'm
8 recalling the original statement on the floor of the
9 United States Senate by Senator George Murphy in 1967
10 articulating the reasons for California to attain its
11 ability to set its own standards. And he said it is
12 because of the extraordinary and compelling problem that
13 has existed and that exists in the State of California
14 that the state has had to make great effort in the past
15 that will undoubtedly be called upon to make even greater
16 efforts in the future to assure that the citizens of the
17 great State of California will have acceptable and clean
18 air.
19 That's still true. There's a lot riding on your
20 continued leadership and moving forward for the health of
21 our citizens. We still have too much nonattainment. We
22 make great progress, but we have much more work to do.
23 So we strongly concur with the recommendation to
24 stay the course in the midterm review. And we also very
25 much agree with the need to begin now to lay the

1 foundation for the next set of standards from 2026 to
2 2030; because it's at that point that we look like we're
3 going to be close to the crossover point where the EVs are
4 going to be cheaper than conventional vehicles and are
5 going to be a favorite choice. But we've got to sort of
6 seed that market and continue with the progress.
7 And I'd also like to urge our friends in the auto
8 industry to think twice about betting on the Trump
9 Administration as their future. You know, one of the
10 things we've wanted all these years is to have stability,
11 to have predictability. Your process has done that. The
12 administration seems prepared to throw a monkey wrench
13 into that process. But I think we're going to be here
14 longer than they are. And I think the auto industry would
15 be well advised not to bet against the State of California
16 when we have done so much together with them to accelerate
17 the progress of the technology.
18 Thank you very much.
19 CHAIR NICHOLS: Thank you. And you were the last
20 witness on our list. So I'm going to close off the public
21 testimony portion and move into some discussion on the
22 part of the Board. And I know a number of my fellow Board
23 members are going to want to have comments on this item.
24 But I'm going to do something that I don't
25 usually do, which is to start the conversation rather than

1 try to wait till the end.
2 So first of all, I want to say that I think it's
3 quite clear that the Air Resources Board is going to
4 affirm the technical reviews that were done by our own
5 NEPA staff as well as the work of a number of independent
6 analysts.
7 I want to make it clear that we invite the global
8 industry to bring us their best cars and trucks and to
9 take advantage of the willingness of our leaders. Not
10 just of the officials, but from all of the groups that
11 you've heard from here that want to work to provide a
12 range of incentives to make these vehicles affordable. We
13 understand that you are in business to make money. And we
14 don't want to interfere with that to any extent more than
15 we absolutely have to to help you help us get the vehicles
16 that we need.
17 We invite you to come and sit down with us, if
18 you have specific concerns about the implementation of the
19 existing regulations that can be addressed without
20 weakening the overall impact, which is what I've heard the
21 leaders of your associations say is what you wanted to do.
22 We want the cleaner cars that will save consumers
23 money and are fun to drive, because that's what we do in
24 California.
25 Now, I also want to turn to the industry

1 representatives who are here, and those who are not here
2 but are based in Washington, to say, what were you
3 thinking? What were you thinking when you threw
4 yourselves upon the mercy of the Trump Administration to
5 try to solve your problems? It just does not make sense.
6 And when we hear today that you didn't really mean to
7 question the validity of the California waiver, well, our
8 newly confirmed head of the Environmental Protection
9 Agency said he was prepared to do just that.
10 What did you mean when you said you didn't want
11 to question the overall thrust of the standards? Why do
12 another review if the current program is basically okay?
13 And if there were changes that needed to be made again on
14 the implementation side, bring them forward and have the
15 discussion. We invite you to do that.
16 So that's my opening here for the rest of the
17 Board to chime in. I'm sure people will have other things
18 they wish to say. But I just want to make it clear that
19 the outpouring of support that we have here today is not
20 just unique to California. You've heard from a number of
21 representatives of major state agencies that have also
22 come to be with us. And I hear from consumers and from
23 activists all over the country as well as all over the
24 world who want to be part of the move to a successful
25 zero-emission vehicle market.

1 So let's take action today on the resolution and
2 then let's move on.
3 So, Dr. Sperling, would you care to comment next.
4 BOARD MEMBER SPERLING: I'll follow Chair
5 Nichols' lead on this.
6 I will say, first of all - backing up just a
7 little bit - is the staff did do an extraordinary job. I
8 mean, that was an extraordinarily sophisticated, careful,
9 quantitative analysis of the situation, both for the ZEVs
10 and for the greenhouse gas standards.
11 And I also want to note that this -- I've been
12 particularly impressed with the speakers today. It must
13 have been probably -- well, probably a quarter or a third
14 nailed it exactly at three minutes and did it in a very
15 articulate way. I mean, I think this has been the best
16 group of speakers we've ever had in terms of being
17 articulate and getting the time.
18 Okay. So getting back to the point at hand.
19 You know, the greenhouse -- so let me just delve
20 a little more deeply into this.
21 So the greenhouse gas standard, all of the
22 evidence, all of the analysis, call it science, call it
23 economics, shows that, if anything, these standards should
24 be even more aggressive. And that's because every single
25 study shows that there's more savings than there is cost,

1 with discounted appropriately and so on. I mean, think
2 about it for a minute. That means this is one of the best
3 regulations or policies anyone has ever adopted. What
4 we're saying is that this saves consumers money, it saves
5 economy -- the economy money. Forget about greenhouse
6 gases, forget about air pollution. It's great before you
7 even -- and then if you add those on, I mean it's even
8 better.
9 So to get back to the -- you know, the Washington
10 D.C. story, you go there, and I don't see any way where
11 the evidence can be shown that the standard should be
12 weakened in any way.
13 Now, I understand the industry wanted -- you
14 know, was concerned about some of the details of it, the
15 alignment and flexibility. And I actually agree they had
16 good points on that. How they got themselves into the
17 situation where they are now is probably, you know, not in
18 anyone's best interest. But being that what it is, you
19 know, I agree, there's some changes that should be made.
20 You know, one of them that really irks me that I'd like to
21 see change is that electric vehicles lose all of their
22 multiplier credit and, not only that, but upstream
23 emissions are assigned to it. And I'm not sure exactly
24 how that's going to be done, because if you take the
25 average for the country, you know, in some places the grid

1 emissions are pretty high.
2 And so that takes away much of the motivation
3 certainly from a regulatory perspective for the car
4 industry to be investing in electric vehicles. So it's
5 moving us in the wrong direction, and the industry itself
6 would agree with that.
7 And so, you know, I'm not the politician so I
8 don't know how this is played -- going to play out. But
9 certainly I know California is going to take a very strong
10 position that, you know, if anything is done, that's fine
11 as long as it's more stringent in fixing some of these.
12 So that's the greenhouse gas story.
13 And then the ZEV story, which is to -- the
14 greenhouse gas one, it's so straightforward and obvious,
15 it's like, you know, okay, that's easy. The ZEV story is
16 perhaps a little more complicated. In many ways -- and
17 not only in many ways. I would say the ZEV mandate has
18 been the most important, most effective policy in the
19 world to accelerate advanced technology, advanced electric
20 drive technology.
21 And we're starting to see that. Okay, you know,
22 it took a while. There were some blips along the way and
23 it had a tortured life for many years. But it played a
24 really important role. It sent a signal that was, you
25 know, important to the industry, to battery makers and so

on, and we're seeing that now. We see great tech -- you know, the car -- the car companies have done a great job. The car technology is very impressive. It's getting better and better. I've driven and owned many of them. The battery costs are coming down quickly, much faster than almost anyone expected. But to go back to what John White was saying, when we as a society, economy, and people focus our resources and our attention on something, it's amazing what we can do. And that's what's happening with batteries. And the same thing, you know, as we gear up with fuel cells, we're going to see the same thing with fuel cells, for sure.

I would say -- having said that, we are not alone. And this is actually a good story. China has soared past us in terms of number of vehicles. They sold 500,000 electric vehicles last year, way more than the U.S. did. Over 300,000 cars, a hundred thousand electric buses, 50,000 electric trucks -- heavy-duty trucks.

Norway has over 30 percent market share for electric vehicles. 30 percent. You know, we're at 3 percent.

So this really is an important policy. Now, the point of this policy though, before I get into some more of the details is, the point of this policy is commercialization, to advance the commercialization of

electric vehicles, of zero-emission vehicles, plug-in hybrids, fuel cells. It's not to reduce air quality -- reduce pollution. It's not to reduce greenhouse gases. Yes, we want those benefits along the way. But those benefits are so tiny at the market shares we're talking about, that the point of this is to accelerate commercialization.

So as we think -- go forward, certainly past 2025, as many people have said, there's lots of reasons and lots of motivations to really ramp up the number of zero-emission vehicles, and we need to be committed to doing that. A regulation by itself can't do that.

So as the staff has indicated, as we've heard from other people, we need a lot more focus on incentives, and we have to make those certain, we have to create more of a certainty in them. They should be at point of sale like it was either New York or Connecticut said they're doing. We need better marketing. We need better -- more infrastructure, both hydrogen and electricity.

And the pricing -- electricity pricing. You know, in California we have these tiered rates in most cases. And that means if you add an electric vehicle to it -- you know, to your household, you actually would pay more unless you had some special electric vehicle rates or time-of-use rates.

1 Now, we're making progress on all of these. The
2 PUC is working on the prices. We are funding more
3 infrastructure. But we've got to do it more and better.
4 And I think that, you know -- Chairwoman Nichols has
5 emphasized this in the past. And I think -- you know,
6 we've got to figure out how to double down on all of
7 those. The PEP collaborative is working. And marketing,
8 I would note also, which is important.
9 Okay. So what does all this mean in terms of any
10 changes on the ZEV side? There is one thing that I feel
11 strongly about, a change that I would like to see. And
12 that is -- it's not a change. It's an extension. And
13 that is what's been known as the transportation system
14 credits. And this is something that right now it -- it
15 was snuck through in 2012. That's not a technical word.
16 (Laughter.)
17 BOARD MEMBER SPERLING: And I didn't notice it.
18 I didn't realize it. And, you know, it's scheduled to be
19 phased out at the end of this year. I think that's a huge
20 mistake, because we're talking about -- as we talk about
21 complementary measures in marketing, this is one of the
22 cheapest, easiest ways to do that. Because what it's
23 going to do is it's a way of getting more of the electric
24 vehicles, the ZEVs into car sharing, into some of the new
25 mobility services out there. And what we've -- if there's

1 anything we've learned is people need to have the
2 experience with these vehicles before they buy them. And
3 we've seen -- we've had market research funded by ARB and
4 others that have shown that the knowledge and awareness of
5 electric vehicles is remarkably low, even for people that
6 are buying new cars. And it's really shocking, you know,
7 when you look at, you know, some of those findings.
8 So this is something that does it easy and cheap.
9 And so I would really argue for an extension of that going
10 forward.
11 The other thing I wouldn't argue with quite so
12 strongly but I believe strongly is -- and especially going
13 forward, is with plug-in hybrids, creating more
14 flexibility. The point -- and certainly 2026 and beyond.
15 We -- the point of the ZEV mandate is to get vehicles out
16 there, to get the industry investing in them and the
17 technology. And we don't -- you know, we're not brilliant
18 enough to know exactly how this is going to play out. And
19 the 177 states especially, they have different markets
20 than us; and we understand that even less well than we do
21 the California market.
22 So I would put that on the table as something to
23 think about. You know, I know there's the, you know,
24 waiver issues and so on. But if there's some way to do
25 that certainly for 2026 and beyond, we need to create more

1 flexibility.
2 CHAIR NICHOLS: Are you not worried about the
3 cold start problem?
4 BOARD MEMBER SPERLING: The cold start problem I
5 think is overstated in the sense that if we have, say --
6 if the plug-in hybrids are, say, 6 percent of the market
7 sales in 2025, and -- the plug-in hybrids are, say, 5 or 6
8 percent, and that would mean they're like 1 or 2 percent
9 of the total market -- and now we're talking about a tiny
10 part of 1 percent. So through 2025, no. I don't think
11 that's a big issue. Beyond it, yes. But we are -- I hope
12 we are adopting new test procedures that will make sure
13 that there will not be any of those, that we fix that. I
14 see that as a temporary problem and that we should be
15 focusing on getting more vehicles out there and
16 commercializing them.
17 CHAIR NICHOLS: Okay. Dr. Balmes, you're next.
18 BOARD MEMBER BALMES: Thank you, Chair Nichols.
19 Well, I'm going to sort of get down into the
20 weeds a little bit more. I brought up earlier Tom
21 Cackette's Jetta Diesel. I turned mine in and bought
22 Chevy Volt, and I want to talk about my experience, you
23 know, buying that vehicle.
24 I went to a local East Bay Chevy dealer where the
25 vehicles were prominently displayed. You first came on to

1 the lot, there were several right next to a Stingray, you
2 know, and they sort of caught attention, looked good.
3 They were clean. They were ready to go.
4 Actually the one that I drove was a fancy one
5 with every available option. And because I was getting a
6 good deal for a Volkswagen, my wife let me buy the fancy
7 one with the Bose stereo.
8 (Laughter.)
9 BOARD MEMBER BALMES: It's fun to drive. I
10 bought it in November. I still haven't finished the
11 original gas tank. I have a half a tank left. And
12 there's no reason that these vehicles can't be marketed
13 effectively.
14 That was an example of a, you know, California
15 dealership, but, you know, you can do this in 177 states.
16 And I don't watch much TV, but I'm a big Warriors
17 fan and I watch Warriors games. And do I see
18 advertisements for plug-in hybrids or battery electric
19 vehicles? No, I see ad after ad for Silverados, F-150s,
20 and Ram trucks. I mean, the industry talks about there's
21 no market for these vehicles. Well, you create market.
22 You put millions of dollars into advertising. You say the
23 public doesn't want to buy these vehicles, but you don't
24 try to sell it to them.
25 And, you know, I can only add my support to what

1 Chair Nichols said about, you know, I don't know where you
2 guys are going - and I'm talking to the auto industry
3 here. For the last few years I've been telling -- I've
4 been listening to how you're cooperating with us, trying
5 to move ahead, trying to help us meet our both air quality
6 and greenhouse gas climate change goals. I don't know.
7 You have to work with us to achieve those goals, not work
8 against us.
9 I want to say also that I want to endorse the
10 issue about a reliable ZEV incentive program. I wish our
11 legislators were here today. They were here yesterday. I
12 think that at least Assemblyperson Garcia's staff person
13 is here. Please take the message back to your assemblyman
14 that we need to have a stable ZEV incentive program if we
15 want the public to continue to buy the cars in the numbers
16 that we need to have them do so.
17 I have a specific question to staff. It's an
18 informational question. The MECA representative asked
19 about a -- had a proposal for a voluntary GHG credit
20 related to -- well, a credit for a voluntary use of a gas
21 particle filter. I just would like staff to comment about
22 that. I'll pause for a second, if anybody can do that.
23 DEPUTY EXECUTIVE OFFICER AYALA: Dr. Balmes, I'd
24 be happy to do that.
25 The proposal that MECA has made, we find it to be

reasonable, so we are committed to working with them and trying to figure out what is the right mechanism to try to promote the deployment of the technology. We agree the technology is a good solution. It's not the only solution. So we're in a good place.

BOARD MEMBER BALMES: Okay. Well, thank you.

And my last point is also directed towards staff.

Dr. Sperling doesn't often say that staff presentations are sophisticated.

(Laughter.)

BOARD MEMBER BALMES: And he -- I want to support his compliment. I really thought that the presentation today was outstanding, and -- I'm even getting choked up here -- because, you know, this agency has proposed and has implemented important zero-emission vehicle and fuel economy standards that are impacting the world, and it's been supported by solid work of our staff.

And, you know, the public support for what our staff has proposed I think is proof of the worth of the work.

Thank you.

CHAIR NICHOLS: Thank you.

Ms. Mitchell, you're next.

BOARD MEMBER MITCHELL: Thank you.

One thing I think we can start with is that this

1 program has shown remarkable progress. It began in 2012.
2 We're only five years into this program and we -- this has
3 just been amazing where we are today, which also leads to
4 a conclusion then in the next five years it could be even
5 more amazing.
6 And I expect we will see some very dramatic
7 changes in the transportation industry as we go forward.
8 And I think that the work of this agency has really been
9 the catalyst to get where we are now.
10 With that, I also want to express a really strong
11 support for our Northeast states. While this program has
12 been successful in California, we need it to be successful
13 across the nation. And the Northeast states in the
14 Section 177 program is a pathway to get there.
15 Those of us who are on the Board, we get your
16 comment letters. And one thing I want to remark on is we
17 got 700 letters from residents in the Northeast states all
18 asking for these electric vehicle cars. And these were
19 just people off the street. They weren't people in the
20 industry. It was 700 people who bothered to write us a
21 letter asking for electric vehicles. And that should be a
22 message to our dealers and our OEMs that, you know, there
23 is a demand for these cars. In fact, in conversations
24 with Tesla, I learned that their best market is the
25 Northeast state. And they've solved some of the problems

1 with cold start. And we also know that Northeast states
2 want all-wheel or 4-wheel vehicles because they have
3 weather patterns that demand that. So OEMs should be
4 looking at that as their future manufacturing goal.
5 So some of things that came out of the testimony
6 that I think we should be looking at is charging stations.
7 Obviously we need infrastructure both for EVs and for
8 hydrogen. And I think that should be something that we
9 look at post 2025. And it was mentioned that perhaps we
10 should have a goal for the number of charging stations.
11 So that's something I think our staff could study.
12 Another thing that we need to be thinking about
13 is that we need to have more EVs in clean vehicles that
14 are shuttle vans, that are light-duty trucks, that are the
15 SUVs, because this is what's happening to our market:
16 People are buying these things with low gas prices, but
17 also because that's what's available. We don't have
18 EVs -- or many EVs in that category. I know we're moving
19 in that direction. But if there's a way that we can
20 stimulate that production, that would be good. And also
21 that's a note for the OEMs that are out there.
22 I think the other thing post 2025 is we need to
23 look at the credits in the market, both for EVs and for
24 plug-in hybrids.
25 There -- we know that there is -- some of that

1 has been a little bit skewed because we had advanced
2 faster than we thought, we got better range vehicles much
3 faster than we thought, and that credit market has been
4 kind of slanted because of some of the advancements that
5 we didn't expect. So that's one thing we should be
6 reviewing.
7 It was also mentioned that the PM standard of 1
8 milligram per mile can be even better. It can be 0.5 as I
9 understood it from the testimony. So let's take a look at
10 that too and study it as a possible goal for future.
11 Again, I want to echo what has been already said
12 about a reliable incentive program. That's really
13 important in these early stages, to get that incentive
14 program going so that we move past early adopters and
15 increase this market. It could be rebates. It could be
16 stickers for the HOV lanes. It could be tax credits. And
17 there's probably some other innovative things we could
18 think of that would stimulate the market.
19 I also think as we look at post 2025, let's look
20 at the global market and compare ourselves against what is
21 happening globally. It was mentioned that -- I think
22 Dr. Sperling said 500,000 sales of EVs in China. And I
23 think we should be comparing ourselves against that market
24 so that we're at least trying to move in that direction.
25 And OEMs should pay attention to that too. The market is

1 global. It's not just California and a few states in the
2 United States.
3 And finally, I think we need to be looking at
4 what is the transformative things that are happening in
5 transportation:
6 Car sharing like Uber and Lyft. And some of
7 those are very involved in first and last mile.
8 The other thing is autonomous cars. I once heard
9 a presentation where someone said the worst thing that
10 could happen to us is autonomous cars, because now you'll
11 have a bunch of cars running around with nobody in them.
12 And that is not good for our congestion problem.
13 But autonomous cars that are zero emission is an
14 opportunity. And so that is an area I think we should be
15 looking at. I don't know exactly how we attack it. But I
16 think that we should be taking into consideration these
17 kinds of new things that are happening in transportation.
18 Thank you.
19 CHAIR NICHOLS: Okay. Next I have Dr. Sherriffs
20 and then Supervisor Serna.
21 BOARD MEMBER SHERRIFFS: Thank you very much.
22 One advantage of being way down on the end here,
23 I've got my own camera.
24 (Laughter.)
25 BOARD MEMBER SHERRIFFS: So I had to say

1 something. You know, use the technology.
2 This has been a remarkable morning and early
3 afternoon. Thinking about what is success. And there has
4 been so much success in this process. Really remarkable
5 and really wonderful to be part of all of the energy
6 that's here, and really grateful to people who have come
7 from far to testify and support the work and help advance
8 what's -- what we're working on.
9 You know, really, well, why do we have advanced
10 clean cars? Well, in fact it is to decrease greenhouse
11 gases and to improve air quality. And it's been
12 remarkable the success that this program has had in terms
13 of, as has been pointing out, advancing technology and
14 commercialization of the technology.
15 We pick a lot on the manufacturers and the
16 dealers in terms of supporting this moving forward. And
17 we all have our stories. And I could talk about what it
18 took to get the battery replaced in my car. I will say
19 and -- for the manufacturer, that was great. They stood
20 behind it. But I had to take the car to the dealer three
21 times and point out to the repair person which was the
22 dial we needed to be looking at that indicated there was a
23 problem with the battery.
24 But maybe this will take care of itself, because
25 we look at the global market and we see the sales in China

1 and we see 30 percent of new cars in Norway. Although we
2 had heard that these things don't work in cold climates.
3 And the last time I looked, Norway was still pretty cold.
4 So maybe this problem will take care of itself.
5 But, you know, we were called earlier. And we
6 all recognize, this really is just the beginning. We're
7 always called to do more. This is great success, but it's
8 just moving forward; and we certainly need to be engaging
9 in that process, looking to 2026 beyond. Because we think
10 about incentives, well, one of the great incentives for
11 the manufacturers is having a clear path forward. That we
12 think hard and long and get it right so that it is an
13 appropriate pathway and a pathway that is going to work
14 and can be counted on.
15 Incentives, so important in terms of developing
16 our infrastructure. It's wonderful to hear how successful
17 places like Connecticut have been.
18 You know, this is so important for air quality
19 for the valley. Every zero-emission vehicle in the
20 valley, boy, that is huge in terms of us trying to get to
21 our PM2.5 and our ozone. But, again, the valley presents
22 its own challenges in terms of being a relatively rural,
23 having the corridors in terms of freight so important to
24 the State's economy. But also reminding us as we look at
25 2026 and beyond, boy, we really need to broaden this, we

1 need to do so much more to bring heavy-duty trucks into
2 this, to help the manufacturers move forward with more
3 options in terms of vans, airport shuttles, those types of
4 things.
5 And pickup trucks. I have lots of farming
6 friends in the valley who say, " 100 miles, that'll work
7 for me. But there's no pickup option that's going to get
8 me around my ranch today." And I know for myself,
9 confession: I have a pickup truck. My wife wants me to
10 get rid of it. It could be our electric vehicle, and that
11 would satisfy me.
12 But it's not an option, yet. So I'm looking
13 forward to the future and looking forward to continuing to
14 work 2026 and beyond. And the sooner we start that, the
15 better.
16 CHAIR NICHOLS: Supervisor Serna and then Mr. De
17 La Torre.
18 BOARD MEMBER SERNA: Thank you, Chair Nichols.
19 So Dr. Sherriffs just stole a little bit of what I was
20 going to say. I have a number of things I want to comment
21 on. But I too have a pickup truck. And, you know, it's
22 an aluminum body, F-150, so it's light weight.
23 But it does occur to me and it sounds like others
24 on this Board that that's certainly a part of the market
25 that has not been exploited in the kind of way that we

1 want in terms of advancing battery electric and plug-in
2 hybrids for the purpose of hauling and towing in some
3 cases. And I think that is certainly something that I'd
4 be looking forward to seeing the chart next time that has
5 the pickup truck icon on the chart. So...
6 One of the things that stood out to me today in
7 terms of the testimony was something Bill Magavern said.
8 And I'm not sure if he's still here or not. But, you
9 know, he reminded us that we are here to essentially
10 make -- in this case make the OEMs meet the market. And I
11 think that is something not to be taken lightly. I mean,
12 as regulators and certainly as some of us are elected
13 officials, sometimes that makes you wince a little bit.
14 But I think in this case that's certainly the best way to
15 think about our role in this, is to interject what we need
16 to see happen here in not just the California market but
17 certainly assisting, as has been noted today, other states
18 in terms of expanding the market for ZEVs in particular.
19 I think what Dr. Sperling said earlier really
20 resonated with me, and I presume others, about, you know,
21 just exposing consumers to the experience is something
22 that I think is absolutely critical. And what I haven't
23 heard, and maybe there's someone that can correct me if
24 I'm misstating this, but it seems to me that there are all
25 kinds of opportunities to do that. For instance, just

1 getting here to this meeting the last two days, we had to
2 rent -- a number of us had to rent cars at the airport.
3 And just kind of wondered out loud whether or not any of
4 the rental car agencies are looking at programs that could
5 expose consumers on a -- obviously on a limited time basis
6 to the experience of driving ZEVs or plug-in hybrids or
7 other types of model vehicles that aren't just based on
8 ICE propulsion. So I think that's an option.
9 I think, you know, the dealers when they have
10 loaners -- when they give loaners to their buyers that are
11 having their vehicle serviced, that's another opportunity
12 to expose the market for a limited time and get people
13 thinking, getting consumers thinking about the ben -- not
14 just the environmental benefits of driving something other
15 than an ICE engine vehicle but the quietness, as someone
16 mentioned, of driving a battery electric.
17 These are all the kind of creative things that I
18 haven't heard yet - and again correct me if I'm wrong -
19 that I think ought to be -- ought to be exploited.
20 And lastly, I think certainly the need to expand
21 our infrastructure has everything to do with the
22 ability -- overall ability to see expansion in the market.
23 I had a visit from someone here that -- in
24 California that is in the business of mobile solar
25 charging stations for plug-in vehicles. I think it's

ingenious. These things are -- basically you drop them down and they're ready to go. They charge themselves. Those of us that serve up here in local government capacities I think have a responsibility to seriously look at technologies like that that are relatively easy. You don't have to have an open trench scenario that's costly and disruptive. You can literally just have these things dropped in parking lots. And there's even a model of this portable charging station, if you will, that can be adapted for street use.

So those are the kinds of things in the menu of kind of creative thinking to expand the market that I think we're going to have to see more of.

And then I'll just end by again thanking staff. I think, as was noted earlier, you've just done a yeoman's job of really providing not just this Board but the public with I think some very clear challenges that we have still but certainly all the complementary policy directives that we need to see the market expand.

Thank you.

BOARD MEMBER SHERRIFFS: The Fowler Library has a solar charging station. It's wonderful.

BOARD MEMBER DE LA TORRE: Thank you.

When I came on the Board, one of the -- the first big thing that I faced was that deal in 2012. I came late

1 2011. And I was getting lobbied by many of the people in
2 this room about that deal. And there were so many
3 unknowns around that deal. This Board had a really hard
4 time trying to anticipate what was going to happen. And
5 we all took that leap of faith.
6 And so here we are doing our midterm review,
7 which was part of the deal back then. So we are following
8 through. We've done the analysis. And we are going to
9 vote in a little bit on this. But I can't think -- you
10 know, I'm trying to think back to 2012. And I can't think
11 of anything in this situation that we're in in 2017 that
12 goes against what we sought out in 2012. I can't think of
13 anything that went wrong in these intervening years. I
14 can't think of anything that is shaky or scary today that
15 we didn't know back then. It's turned out pretty damn
16 well.
17 And so when you do a midterm review it's -- in my
18 mind, it's an off-ramp possibility. Well, there is no
19 damn off-ramp. We're doing exactly what we said we were
20 going to do. You're doing exactly what you said you were
21 going to do. In a couple of years we're going to have
22 double the number of electric vehicles on the streets or
23 being offered for sale, which I think is going to really
24 kick in the market with more variety. Some of you have
25 heard me talk about some of the electric vehicles that I

1 think that are less than attractive.
2 (Laughter.)
3 BOARD MEMBER DE LA TORRE: I think that's going
4 to change, because there's going to be so many more
5 options - cool options, big options, small options,
6 different options. 200-mile options. That was not
7 something we were talking about in 2012.
8 Maybe Dan was.
9 (Laughter.)
10 BOARD MEMBER DE LA TORRE: So, I mean, here we
11 are in the middle of this thing -- well, not quite the
12 middle but where we proposed we were going to check this
13 thing out, and it's all working. So why would we take the
14 off-ramp? Because something has happened in Washington
15 D.C.? And I can appreciate how hard it is for the OEMs.
16 It's like being between two bickering parents. Right?
17 (Laughter.)
18 BOARD MEMBER DE LA TORRE: And we're the cool
19 one, by the way.
20 (Laughter.)
21 BOARD MEMBER DE LA TORRE: I can understand. I
22 can appreciate how difficult that is. I can understand
23 that on the one hand you have environmental measures, that
24 is our purview; and on the other hand you might have, say,
25 manufacturing incentives or tariffs that might be

1 implemented on imports. I get it. It's tough.
2 But, I'm going to paraphrase a conversation I had
3 with one of your associations, after the other association
4 sent a letter to the Trump Administration saying you
5 wanted to roll back some of this stuff. And that was that
6 you take a long-term global view of the marketplace: That
7 there is a world marketplace; that there is a United
8 States marketplace; and there's a California marketplace,
9 and those are all woven together. And that you need to do
10 product development over the long term and you need to
11 develop products with an eye toward where that global
12 marketplace is going, to Dan's point about sales in other
13 countries. And you're doing that. You've been doing that
14 for a few years now.
15 So, whether it's four years or eight years, why
16 would you change for U.S. market or for the California
17 market when there's a world market out there that is
18 heading in this direction? And I would argue that the
19 California market and the world market are exactly on the
20 same page regardless of what's going on in Washington D.C.
21 So from a business standpoint of the biggest
22 market and the longer term direction, this is the right
23 way to go to stay on track here. So if a divorce is going
24 to happen at some point, we are going to litigate that
25 divorce strongly.

1 And I think the point that was made from the VW
2 settlement earlier - right? - that there were 500,000 of
3 these cars here in the United States, but 8 million of
4 them in Europe. That should tell you what I'm saying
5 here, that I don't -- I'm not making this stuff up. We
6 are just a little piece of the pie, even the United
7 States. I know it's hard for us to not be, you know, the
8 greatest all the time.
9 (Laughter.)
10 BOARD MEMBER DE LA TORRE: And then in terms of
11 what's going on in Washington, I would just point out, you
12 know, within the first hundred days we've had that
13 spectacular success of the travel ban. And the headline
14 just right now a couple of hours ago, "House GOP gives up
15 on health care bill as Trump suffers first legislative
16 defeat."
17 (Applause.)
18 BOARD MEMBER DE LA TORRE: So when your parents
19 are fighting --
20 (Laughter.)
21 BOARD MEMBER DE LA TORRE: -- you can see which
22 one has their act together and which one doesn't.
23 (Applause.)
24 BOARD MEMBER DE LA TORRE: Again, we understand,
25 I understand this difficult spot you're in. But your

1 interests, your business interests long term and in the
2 marketplace of vehicles in this world are more aligned
3 here than they are elsewhere.
4 And I'll close with again going back to the
5 beginning of all this, which is "a deal is a deal." There
6 were three parties at that table back in 2012. We're one
7 of those parties, and we are going to continue to exercise
8 our authority under that deal until we decide that that
9 deal is no longer valid.
10 Thank you.
11 CHAIR NICHOLS: Thank you. Next in line is Vice
12 Chair Berg, who I believe is going to actually propose the
13 resolution.
14 VICE CHAIR BERG: Well, I do see -- Diane, did
15 you want to make a comment?
16 BOARD MEMBER TAKVORIAN: Is that before --
17 VICE CHAIR BERG: Yeah, I'm going to move. Okay.
18 BOARD MEMBER TAKVORIAN: Thank you.
19 Well, hard to follow Member De La Torre. I would
20 say current White House tenant, 0; human environmental
21 rights, 3. Let's call it that so far, at least on the
22 books. So I'd say bet on California if that's a summary.
23 And I want to thank all of CARB. I am inspired
24 by our Chair's opening comments, and I think that
25 this -- this is a CARB legacy issue. And it's clear that

1 this Board is committed, the staff is committed. You've
2 made it happen, and not just for California and the United
3 States but for the world.
4 Since we're all disclosing our vehicles, I guess
5 I need to say that --
6 (Laughter.)
7 BOARD MEMBER TAKVORIAN: -- I drive a 2012 Volt.
8 And my experience in purchasing was probably different
9 than Dr. Balmes. It actually wasn't in the front lot. I
10 knew what I wanted when I walked in. And there was a
11 sales guy that said, "Really? You sure? I can put you in
12 this" whatever. But I knew what I wanted, and it has
13 since then been a really positive experience. But that's
14 four years -- five years and I think it's really changed.
15 Unfortunately there's one mechanic at our
16 dealership that -- and, you know, we're on a first-name
17 basis and I know what his days on and off are, so I know
18 when I can get service.
19 But -- you know, but I think it's changing and
20 it's great to be part of that evolutionary change and to
21 watch those things happen and to hear these stories.
22 I will say - and no one will be surprised by
23 this - that, you know, one, low income communities and
24 disadvantaged communities are benefiting from these ZEVs
25 being on the road. We are located next to freeways and

1 next to major roadways. So the cleaner these cars get,
2 the less polluted our communities get, the less asthma our
3 kids have. So that's a huge advantage, and no one can
4 deny that.
5 The other fact is is that our communities are not
6 part of this story yet. And we need to be. So we need to
7 improve the incentives. I endorse what folks have said
8 about really needing to make those incentives better, and
9 we need to make them more available for low and moderate
10 income families - I think that's really important - and
11 for the secondary market. It's important for folks to be
12 able to purchase these cars on the second round.
13 So I support the measure and I congratulate
14 everyone who's worked so hard on it. And everyone who is
15 here today, we really appreciate all of your hard work on
16 it.
17 BOARD MEMBER BALMES: Before you go and propose
18 the resolution, I just want to say -- I've already shared
19 this with my partners here -- my Chevy Volt dealer must
20 have heard me, because they're now trying to sell me a
21 Volt. "Electric cars of the future. Come see the new
22 Chevrolet Volt here at" --
23 (Laughter.)
24 BOARD MEMBER BALMES: "Please call for a test
25 drive."

1 (Laughter.)
2 VICE CHAIR BERG: Madam Chair, understanding the
3 only thing that is preventing us to go to lunch is moving
4 Resolution Number 17-3. I propose that we adopt --
5 BOARD MEMBER SHERRIFFS: Second.
6 VICE CHAIR BERG: -- Resolution 17-3.
7 BOARD MEMBER BALMES: I enthusiastically second.
8 CHAIR NICHOLS: All right. Will all in favor
9 please signify by saying loudly aye.
10 (Unanimous aye vote.)
11 CHAIR NICHOLS: Any opposed?
12 None opposed.
13 No abstentions.
14 All right. Thank you all so much.
15 And we will take a lunch break, and we will be
16 back to take up our last item of the day, which is the
17 report on the ZEV investment plan after lunch at 2 -- no,
18 wait -- 3 -- 3 o'clock.
19 (Off record: 1:44 p.m.)
20 (Thereupon a lunch break was taken.)
21
22
23
24
25

1 A F T E R N O O N S E S S I O N
2 (On record: 3:06 p.m.)
3 CHAIR NICHOLS: Ladies and gentlemen, we're ready
4 to resume the meeting.
5 We have quite a number of people who've signed up
6 to talk on this item. So let's just get started with the
7 staff presentation.
8 This is the discussion of the First Draft
9 Volkswagen Zero-Emission Vehicle Investment Plan.
10 The diesel emission enforcement case has been
11 settled through a series of partial consent decrees
12 covering mitigation of the emissions caused by the
13 noncompliant diesel vehicles, vehicle buy-back and repair
14 solutions to address the polluting vehicles and compensate
15 the vehicle owners, and a commitment by the company to
16 invest in zero-emission vehicle programs that will support
17 the ZEV market.
18 Last December, staff updated the Board on
19 activities associated with implementing part of a
20 Volkswagen 2 liter engine diesel partial consent decree;
21 specifically, the zero-emission vehicle investment
22 commitment.
23 Since the December update, a settlement for the 3
24 liter engines and also a penalty settlement have each been
25 agreed on. The two new settlements will bring another

1 $220 million to California along with other benefits such
2 as a required increase in available Volkswagen ZEV models
3 and vehicle types. Today's update is focused primarily on
4 the investment commitment portion of the 2 liter consent
5 decree.
6 Just as a reminder, because this comes up every
7 time this topic comes up again, Appendix C, the ZEV
8 investment settlement, is not either a civil penalty or
9 mitigation. It does commit Volkswagen to investing $800
10 million in California on ZEV infrastructure, brand-neutral
11 public awareness marketing, increasing access to ZEVs, and
12 green city projects.
13 So if done well, this investment will benefit
14 Volkswagen in their new ventures into the ZEV world
15 without a doubt. But it will also benefit equally, if not
16 more so just based on numbers, the other firms and
17 stakeholders that are involved in ZEV as well.
18 In February, staff provided Volkswagen with a
19 publicly available guidance document intended to inform
20 the company's first 30-month ZEV investment plan. This
21 guidance document was based on public input, feedback from
22 the Board, and input from our sister state agencies, as
23 well as the California Legislature.
24 Earlier this month, as required by the consent
25 decree, Volkswagen submitted a draft ZEV investment plan

1 to ARB staff. I look forward to hearing more about the
2 plan, in particular how well it aligns with the
3 requirements of the consent decree and our February
4 guidance.
5 So, Mr. Corey, will you please introduce this
6 item.
7 EXECUTIVE OFFICER COREY: Yes. Thanks, Chair
8 Nichols.
9 So Appendix C of the 2 liter partial consent
10 decree requires investment plans noted by Volkswagen. And
11 Volkswagen must invest, as you noted, $800 million in ZEV
12 projects in California over four consecutive 30-month
13 periods.
14 Eligible projects include installing
15 zero-emission vehicle fueling infrastructure,
16 brand-neutral consumer awareness campaigns to increase
17 awareness of ZEVs, and therefore support growing ZEV
18 vehicle market and projects that will increase access to
19 ZEVs for all consumers in California, including those in
20 lower income and disadvantaged communities. VW may also
21 invest in green city project.
22 As noted, VW recently submitted its first plan to
23 ARB. This plan is currently being reviewed by ARB staff
24 with respect to its alignment with the consent decree and
25 the guidance by ARB to VW. This presentation of the Board

1 will review key elements of the consent decree and the
2 guidance document sent to VW, and provide an overview of
3 VW's draft plan in its adherence to the consent decree and
4 guidance, recognizing we're early in the review process.
5 Ellen Peter, our chief counsel, will now make a
6 brief statement providing the legal context for this item.
7 Ellen.
8 CHIEF COUNSEL PETER: Thank you, Richard.
9 VW has signed settlement agreements with owners
10 and lessees of the 3 liter and 2 liter diesel cars with
11 its VW dealers and with various state attorney generals.
12 In addition, VWAG, the German parent company, pled guilty
13 to criminal charges and must pay a $4.3 billion fine.
14 To date these settlements total over 20 billion
15 in liability. Moreover, many lawsuits are still pending
16 against VW around the country and around the world.
17 There are four settlement agreements that ARB
18 signed with Volkswagen. One is already approved by the
19 Court. And three agreements still need to be considered
20 by the Court probably on May 11, 2017.
21 From the settlements that ARB signed, California
22 will receive 153.8 million in penalties and costs, 423
23 million in mitigation trust monies, and an additional 25
24 million for low income Californians.
25 VW simply writes checks. They cannot touch this

1 money.
2 The market for clean cars was distorted by VW's
3 marketing of their illegal diesel cars. One of the
4 settlement agreements VW signed with ARB requires VW to
5 invest 2 billion nationwide in zero-emission
6 infrastructure and programs over the next 10 years. 40
7 percent of that amount, 800 million, must be spent in
8 California. The shorthand reference to this money is
9 Appendix C.
10 The Court-approved settlement places conditions
11 on those investments. But in contrast to the other
12 monetary relief, this is an injunctive term and it's not a
13 penalty. VW must meet the consent decree's requirements
14 contained in Appendix C, but the penalties are in other
15 parts of the agreement, not in C.
16 Because staff's update today focuses on Appendix
17 C, and since it's only one element of the agreements, I
18 wanted to make this comment first up front just to set the
19 stage.
20 Thank you.
21 EXECUTIVE OFFICER COREY: Thanks, Ellen.
22 Now, I'll ask Jeffrey Lidicker of the Emissions
23 Compliance Automotive Regulation and Science Division to
24 give the staff presentation.
25 Jeffrey.

1 AIR RESOURCES ENGINEER LIDICKER:
2 (Thereupon an overhead presentation was
3 Presented as follows.)
4 AIR RESOURCES ENGINEER LIDICKER: Good afternoon,
5 Chair Nichols and members of the Board.
6 Today I will be providing an update on the
7 implementation of the Volkswagen diesel settlement, in
8 particular Appendix C, the ZEV Investment Commitment. My
9 presentation will then provide a summary of VW's ZEV
10 Investment Plan and, finally, I will go over a timeline of
11 next steps.
12 --o0o--
13 AIR RESOURCES ENGINEER LIDICKER: Before we get
14 into the contents of the submitted Draft ZEV Investment
15 Plan, new settlement agreements have been reached between
16 VW, the U.S. EPA, and United States Department of Justice,
17 and the California Air Resources Board since the last
18 Board update in December. In addition to the approved 2
19 liter settlement, there is now a 3 liter and a civil or
20 penalty agreement pending court approval.
21 First, let's review the 2 liter settlement
22 approved by the federal judge last year. On October 25th,
23 2016, the United States District Court for the Northern
24 District of California approved a proposed partial consent
25 decree between ARB, VW, U.S. EPA, and the United States

1 Department of Justice. The consent decree partially
2 resolves Clean Air Act and California State claims against
3 VW for equipping its 2 liter diesel vehicles with defeat
4 devices. This consent decree mitigates the environmental
5 harm from the violations including the excess emissions
6 from 2 liter diesel cars on the road. There are four
7 elements of the consent decree. Each element is described
8 in a separate appendix.
9 --o0o--
10 AIR RESOURCES ENGINEER LIDICKER: The 2 liter
11 agreement requires Volkswagen to pay billions of dollars
12 to address the vehicles on the road through a buy-back or
13 fix if approved by ARB and EPA. It also establishes a
14 mitigation trust VW will pay for to mitigate excess NOx
15 emissions as well as an excess $800 million -- $800
16 million ZEV investment commitment. About $381 million
17 from the NOx mitigation trust will come to California to
18 be spent by the State.
19 Under the ZEV investment commitment VW will
20 invest in eligible projects including ZEV infrastructure,
21 access to ZEVs via a green city, and awareness, all of
22 which will be discussed in more detail shortly.
23 --o0o--
24 AIR RESOURCES ENGINEER LIDICKER: The VW 3 liter
25 partial consent decree was approved upon in December of

1 last year and has not yet been approved by the judge.
2 Under the 3 liter agreement VW will continue almost $42
3 million to -- contribute almost $42 million to the NOx
4 mitigation trust for the State to spend, and $25 million
5 to the Air Pollution Control Fund intended for the State
6 to spend on ZEV-related projects for low income
7 Californians. Also, in the 3 liter California agreement
8 are requirements for a second green city comprised
9 primarily of disadvantaged communities. Additionally, new
10 ZEV models and vehicle types, such as crossover vehicles,
11 are to be brought to the California market in 2019 and
12 2020. The 3 liter agreement also includes a requirement
13 that VW sell at least 5,000 new ZEVs per year in
14 California from 2019 to 2025.
15 --o0o--
16 AIR RESOURCES ENGINEER LIDICKER: Finally, a
17 civil penalty agreement, which covers both 2 and 3 liter
18 diesel engines, has been reached, but also has not yet
19 been approved by the judge. This agreement provides that
20 VW will pay $153.8 million in penalties into the
21 California Air Pollution Control Fund in addition to
22 injunctive relief.
23 The different elements of the settlement work
24 together to address the need to make the vehicle owners
25 whole through either buy-pack or repair of the vehicles,

1 mitigation of the environmental harm caused by the
2 increased emissions coming from the cars, actions to
3 repair the green car market through the support of the ZEV
4 market and, finally, penalties to push -- punish VW for
5 wrongdoing and deter others from violating our standards.
6 --o0o--
7 AIR RESOURCES ENGINEER LIDICKER: This slide
8 summarizes the VW monetary settlements in one table, and
9 clarifies the distinct intentions for each category of
10 funding. In the far left column, the three parcel
11 settlements are listed.
12 In the middle column are the traditional monetary
13 relief sums, which are mitigation funds and penalties.
14 In the column on the right is the injunctive
15 relief, or more innovative agreement benefits. In
16 particular, the $800 million is a commitment by VW to
17 invest in ZEV support in California. This investment is
18 expected to have global impacts that transcend the borders
19 of California, and that will hopefully support the vehicle
20 market both in California and in the rest of the United
21 States.
22 Although the funds are to be spent by VW,
23 California has retained parameters within which the funds
24 must be spent. We expect that the result is that at the
25 end of the 10-year spending commitment the investments

1 will not shut down, not be removed, but that they will
2 continue on in service. And in order for this
3 self-sustaining goal to be achieved, VW may be able to
4 benefit from its investments and a profit by year 10 is
5 possible and even necessary.
6 Although some of the monetary relief funds go to
7 a trust and some go to the California Air Pollution
8 Control Fund, in total there will be approximately $600
9 million for the State to spend, which is completely
10 separate and different from the sum VW will spend in
11 California.
12 Total settlement funding for California amounts
13 to almost $1.4 billion. To put the $1.4 billion into
14 context, the national amounts VW will spend including its
15 commitment to buy back or fix affected vehicles over $14.7
16 billion, not even including the 3 liter buyback or fixed
17 costs.
18 --o0o--
19 AIR RESOURCES ENGINEER LIDICKER: This slide and
20 the next slide summarize Appendix D, the Environmental NOx
21 Mitigation Trust, which was discussed at the December
22 Board hearing, and provide an update in light of the new
23 arrangements.
24 California will receive $381 million from the
25 trust under the 2 liter agreement and $42 million from the

1 trust under the 3 liter agreement to California to
2 mitigate the total lifetime excess NOx emissions resulting
3 from the use of illegal defeat devices.
4 The trust will fund specified mitigation actions
5 to replace older, dirtier, heavy-duty vehicles and
6 equipment with cleaner vehicles and equipment.
7 The consent decree specifies nine eligible
8 mitigation action categories that can be funded. They
9 include: Scrap and replace funding for on-road freight
10 and drayage trucks; transit, shuttle and school buses;
11 ferries and tugs; and off-road freight equipment;
12 Shorepower for ocean-going vessels; and
13 Up to 15 percent of the trust may also be used to
14 fund light-duty electric vehicle charging stations and
15 hydrogen refueling stations.
16 --o0o--
17 AIR RESOURCES ENGINEER LIDICKER: Based on past
18 experiences with states other than California, U.S. EPA
19 required the use of a trust for the mitigation fund. The
20 trustee, Wilmington Trust, was approved by the judge as of
21 March 15th, and the mitigation trust is expected to be
22 effective later in 2017.
23 VW will deposit the required funds into the trust
24 in three equal annual installments beginning within 30
25 days after the trust effective date. The trustee will be

1 responsible for disbursing the funds. The Governors of
2 each state will name a respective lead agency to manage
3 the trust funds allocated to that state. The lead agency
4 for California has not yet been named.
5 --o0o--
6 AIR RESOURCES ENGINEER LIDICKER: As mentioned,
7 the Governor will identify a lead agency to act on the
8 State's behalf in implementing California's allocation of
9 the trust.
10 Once the Governor has identified a lead agency,
11 that agency's task will include developing, through a
12 public process, a beneficiary mitigation plan that
13 describes the overall use of the funds; implementing the
14 beneficiary mitigation plan and the mitigation actions
15 identified in the plan; and submitting semi-annual reports
16 to the trustee on the implementation status of the
17 mitigation actions.
18 Staff will present a status update on Appendix D
19 to the Board later this year.
20 --o0o--
21 AIR RESOURCES ENGINEER LIDICKER: Now I will turn
22 to the 2 liter agreement's ZEV Investment Commitment in
23 Appendix C. This portion of the 2 liter consent decree
24 includes the following:
25 A commitment for VW to invest $2 billion over a

1 10-year period in ZEV-related programs in the nation. Of
2 that $2 billion, $800 million will be invested in
3 California, which is about 40 percent of the total
4 commitment.
5 The investments will be carried out in four
6 30-month spending cycles, with about $200 million being
7 spent in each cycle. For each ZEV investment cycle, VW
8 will submit a plan to ARB for review and approval, and the
9 investments made will be reviewed annually by a third
10 party auditor.
11 The goals of the investment plan laid out in the
12 consent decree are to promote and advance the use and
13 availability of ZEVs in California by supporting
14 transportation electrification, supporting the next
15 generation of zero-emission vehicles, growing the ZEV
16 market, and supporting access to ZEVs. This could include
17 increasing access to low- and moderate-income consumers
18 and disadvantaged communities.
19 AIR RESOURCES ENGINEER LIDICKER: The 2 liter
20 consent decree establishes eligible investment categories
21 for VW that support the goals of Appendix C.
22 These include: ZEV infrastructure, brand-neutral
23 education and public awareness campaigns, ZEV access
24 programs and a green city initiative.
25 Pending judge approval of the 3 liter Consent

1 Decree, a second green city will be funded from the 2
2 liter funds that must be comprised of primarily
3 disadvantaged communities.
4 --o0o--
5 AIR RESOURCES ENGINEER LIDICKER: We'll turn now
6 to a review of milestones to date for Appendix C and then
7 begin the summary of the VW ZEV Investment Plan.
8 Recall that the 2 liter partial consent decree
9 was approved by a federal judge in October of last year.
10 Subsequently ARB held a public workshop, a public Board
11 hearing, and a public open comment period last year
12 specifically to gather public comment to use in developing
13 the guidance document, which ARB submitted to VW on
14 February 10th of this year.
15 The guidance document represents a summary of
16 California's priorities and advice based on public input
17 regarding ZEV investment opportunities consistent with the
18 objectives and criteria set forth in Appendix C.
19 VW's draft ZEV Investment Plan was posted online
20 for public access and comment on March 14th. At the same
21 time, a notice went out via listserv to notify members of
22 the public that the draft plan was available.
23 --o0o--
24 AIR RESOURCES ENGINEER LIDICKER: ARB approval of
25 the VW ZEV Investment Plan is based primarily on the terms

1 of the 2 liter Partial Consent Decree, specifically in
2 Appendix C. All spending in the plan must be within the
3 eligible spending categories of ZEV Infrastructure, ZEV
4 Access, ZEV Awareness, and Green City.
5 Examples of specific requirements for projects
6 include brand-neutral ZEV public awareness efforts; and
7 should VW create any new companies or services to comply
8 with the consent decree, such as a car-sharing company, EV
9 freight service, or an EV charging company, all associated
10 marketing cannot mention any automobile brand in writing
11 or display any automobile brand logos.
12 --o0o--
13 AIR RESOURCES ENGINEER LIDICKER: The consent
14 decree also requires that the ZEV Investment Plan:
15 Provide a description of all ZEV investments, contain
16 an explanation of how each investment makes progress
17 towards and/or meets one or more of the goals identified
18 in the consent decree;
19 Contain an estimated schedule for implementing
20 each investment and milestone of each project in 6-month
21 intervals; and
22 Contain projections of anticipated credible costs
23 associated with each investment broken out by 12
24 stipulated accounting categories.
25 --o0o--

AIR RESOURCES ENGINEER LIDICKER: I'll turn the presentation now to a summary of VW's first ZEV investment plan submittal. ARB received the plan about two weeks ago and it is undergoing review.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: To start, this slide shows a breakdown of how VW proposes to split its first $200 million investment cycle funds.

The table shows in millions of dollars the approximate allocation of first-cycle funds by spending category. You can also see the national spend along with California numbers and the totals along the bottom.

As you can see, with the national investment of $300 million, the total VW investment in California and the nation combined will be half of a billion dollars.

For California, VW proposes to spend $120 million, or 60 percent of the budget, on ZEV infrastructure; $44 million, or 22 percent, on Green City initiatives; and $20 million, or 10 percent, on ZEV education and access programs. Overhead for all of these activities is projected to be less than 10 percent.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: I will now summarize the EV charging network vision that VW includes in its plan submittal.

1 For locations with long parking times, such as at
2 multiple unit dwellings and at the workplace, VW's plan
3 includes installation of level 2 chargers that have
4 approximately 7.2 kilowatts of power. This power equates
5 to about 20 minutes of range for each hour charge. These
6 installations would benefit a broad cross-section of
7 drivers who have not been served by the traditional
8 at-home charging model.
9 For locations with medium parking times, such as
10 at retail or municipal garages, VW's plan includes
11 installation of level 2 chargers or even 50 kilowatt DC
12 Fast Chargers. VW's plan also includes experimental
13 community depots. These community depots would be
14 conveniently located adjacent to multi-unit dwellings but
15 don't currently have charging access, and will provide
16 fast-charging capabilities.
17 This new concept simulates a gasoline station and
18 has the potential to serve disadvantaged communities.
19 VW's plan notes that some of these community depot
20 stations may be at the "super" 150 kilowatt power level
21 for even faster charge times. DC fast chargers installed
22 to date are typically only 25 to 50 kilowatts by
23 comparison. The community depots are a new concept that
24 would provide data and learnings for the future.
25 For locations with extremely short parking times,

1 such as along highways, VW's plan includes installation of
2 150 kilowatt super fast chargers and also some 320
3 kilowatt chargers. These very high-powered chargers are
4 designed to respond to anticipated future ZEV needs.
5 The plan describes bringing two innovations to
6 the market with these investments: The community depots
7 designed to function as electric gas stations for those
8 who cannot charge at home, and highway fast chargers that
9 are up to six times faster than currently installed
10 chargers. Chargers this fast could provide 200 miles of
11 range in potentially just over 10 minutes.
12 --o0o--
13 AIR RESOURCES ENGINEER LIDICKER: This slide
14 shows the overall EV charging infrastructure budget and
15 timeline in the plan for the first 30 months. The plan
16 allocates $40 million, or one-third of the budget, to the
17 community-based or local charging networks, which would be
18 expected to yield over 350 stations.
19 $65 million, or 54 percent of the budget, is
20 allocated to the long-distance highway network, which
21 would be expected to yield over 50 stations.
22 According to ARB's estimate, the total $120
23 million investment in EV chargers is expected to satisfy
24 less than 10 percent of California's estimated demand
25 based on the State's goal to have enough infrastructure in

1 the State to support 1 million ZEVs by 2020.
2 This table, reproduced from the VW ZEV investment
3 plan, shows the approximate timeline for the development
4 and installation of the EV charging stations over the
5 first 30 months.
6 Even more chargers could be installed in
7 subsequent 30-month cycles. Adherence to this timeline is
8 dependent upon when the ZEV Investment Plan is approved by
9 the State.
10 --o0o--
11 AIR RESOURCES ENGINEER LIDICKER: VW's ZEV
12 Investment Plan describes how the infrastructure plan was
13 developed. This includes the use of a gap analysis to set
14 the number of charging stations and their proposed
15 locations. This gap analysis is based on the difference
16 between the currently installed infrastructure and the
17 projected demand. VW's proposal is to locate stations
18 where they are most needed after taking into account
19 existing stations. This would mitigate the effect on
20 existing companies, as any location that already has
21 adequate infrastructure won't be considered for new
22 stations.
23 The Plan describes the total investment amount
24 for EV infrastructure in the first 30-month cycle as being
25 $120 million. Lastly, the Plan states that the planned

network will be interoperable, meaning that there will be universal access. All chargers would accept several forms of payment, including credit cards, and all nonproprietary charging standards would be supported.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: This slide details -- shows the details of the community or local charging network described in the Plan submittal.

The Plan states that over 350 EV charger stations are targeted to be installed in communities. The plan calls for a mix of charger types including level 2 and multiple power level DC fast chargers. Installations in multi-unit dwellings and workplace locations, on which an emphasize was placed at the Board hearing in December, would benefit underserved communities.

As I'll describe further in coming slides, VW proposes an initial focus for its community and local charging in five metropolitan areas of California.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: Cash guidance to VW articulated the need for investments not to be sprinkled all over the entire state and to learn from mistakes made in the past where some installed infrastructure has gone unused.

VW's plan selects for EV charger installations

five major metropolitan areas that cover the majority of the projected ZEV adoption. VW notes that other areas may be included in subsequent spending cycles.

VW's approach would insure initial investments are utilized, which will ultimately drive success throughout the State of subsequent investments. The following slide describes the methodology laid out in the plan in more detail.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: This image comes from the VW ZEV Investment Plan and shows the process VW describes in the plan to select the five areas for EV charging installation in the first spending cycle. The VW plan states that the decision process for selecting these areas and allocating funds included an analysis of each region's projected needs versus current supply.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: Switching now to the long distance network chargers, this is a map provided by VW in the ZEV Investment Plan submittal that shows the upper two quartiles of the CalEnviroScreen in red and yellow. Imagine, if you will, a highway network of approximately 50 stations spanning east to west and north to south.

VW's plan states that roughly 25 percent of these

chargers will be in communities in the top quartile of the CalEnviroScreen scores, and over 50 percent, or half, of the chargers will be in communities in the upper half of the CalEnviroScreen.

These DC fast charger stations may act as anchor investments supporting communities that currently have little or no ZEV infrastructure. Installation of over half of the VW long-range EV charger stations in disadvantaged communities may spur EV adoption.

Characteristic of long-range charging is the desire for the shortest possible charge time. To answer this challenge, VW proposes a network that would consist of 150 kilowatt and 320 kilowatt chargers, which are three to six times faster than current DC fast charger equipment. These higher power DC fast chargers will enable fast charging times for vehicles on the horizon with longer range. In short, these chargers will be future proofed against technology development over time.

VW describes a network that would cover about 12 highways, with each site in the network having an average of five plugs with some of each charging standard.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: This table from the VW ZEV Investment Plan shows more detail about the charger network locations. The Plan's goal is to create a

1 California highway network designed to place high speed
2 charging stations along the long-distance routes with the
3 highest estimated ZEV traffic, as well as to link the
4 prioritized metro areas to form a cohesive statewide
5 network. Many of these locations could also serve
6 disadvantaged communities.
7 --o0o--
8 AIR RESOURCES ENGINEER LIDICKER: Now I will move
9 on to the Green City portion of the VW ZEV Investment Plan
10 submittal.
11 If the 3 liter agreement is approved by a judge,
12 there will be two Green Cities, with the second one
13 predominantly consisting of disadvantaged communities.
14 Thus, VW's Plan selects the first Green City based on its
15 composition of disadvantaged communities secondarily and
16 primarily for its potential success and potential
17 benefits.
18 This first city will grow the Green City
19 technology and business models, which do not exist
20 anywhere in the U.S. at this time.
21 It will spread the word to other cities, acting
22 as a demonstration ground and as an example or model.
23 Lessons learned from this city would inform
24 planning and decisions for the second Green City and
25 contribute greatly to the second Green City's likelihood

of success.

Although the Plan envisions investing in several services and models relying on technology not yet developed, such as possibly autonomous vehicles in later spending cycles, VW proposes that the first spending cycle consist of ZEV car-share and ZEV delivery services. These are intended to increase accessibility of ZEVs to city inhabitants and create a green mobility habitat. The Plan sees these initiatives as serving as pilots to help spur the widespread adoption of ZEVs and mobility services.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: As mentioned, VW's stated objectives for the Green City program are to offer a set of ZEV initiatives that are accessible to the city inhabitants and create a green mobility habitat. These initiatives should be leveraged to offer residents better quality of life through enhanced mobility and improved air quality.

This edited figure also comes directly from the VW ZEV Investment Plan and presents the analysis that led to identification of the first Green City candidates.

Step 1 on the figure indicates that VW began its analysis by looking for a city with a population size of greater than 400,000 residents, which the Plan describes as a city large enough for scalability of projects, with

1 demand for car-sharing programs and the potential for
2 increasing ZEV access to disadvantaged communities.
3 Step 2 on the figure indicates that VW evaluated
4 each of the remaining cities for Mobility Fit, which it
5 further defined in the displayed subfactors: Mobility
6 demand or the VMT of the city, the community flow patterns
7 specific to the city, and an evaluation of the other
8 transport services available within the city (such as
9 Car-share or Uber or otherwise). The plan explains that
10 these factors are considered against the functionality of
11 ZEVs that will be used in the Green City programs.
12 Step 3 on the figure indicates that VW then
13 evaluated the cities for potential impact, which is
14 further defined in the displayed subfactors: Societal
15 Impact, which refers to the magnitude of the potential
16 change; Implementation Feasibility, which refers to the
17 practicality of implementing such programs in a particular
18 city; and Awareness Impact, which refers to the potential
19 impact on city residents and possibly other entities
20 outside the city.
21 The Plan then combined the scores from steps 2
22 and 3 to arrive at a final score for each city. You can
23 look at the posted ZEV Investment Plan on ARB's website to
24 see the weighting system described in the Plan. ARB staff
25 are still evaluating this city selection process.

1 --o0o--
2 AIR RESOURCES ENGINEER LIDICKER: The Plan
3 identified three potential Green City initiatives on which
4 to focus: ZEV car-sharing, ZEV delivery fleet, and a ZEV
5 taxi fleet provider. To support these initiatives, the
6 Plan proposes the installation of approximately 50 EV
7 chargers for the ZEV Car-share program and 25 more for the
8 ZEV delivery fleet in the first 30-month cycle.
9 The Plan's proposed first Green City is
10 Sacramento.
11 --o0o--
12 AIR RESOURCES ENGINEER LIDICKER: Moving on to
13 the ZEV Awareness Campaign outlined in the VW ZEV
14 Investment plan, we see a budget of $20 million in
15 California for this first 30-month cycle.
16 These programs must be brand neutral, as
17 stipulated in the consent decree, and must not feature or
18 favor VW group vehicles. However, they may say "sponsored
19 by VW" at the end, but neither that message nor VW's name
20 or brand may be prominently displayed.
21 The VW ZEV Investment Plan describes a multimedia
22 or multi-channel ZEV awareness campaign. The proposed
23 multimedia approach utilizes each media channel to deliver
24 a different part of the message. The Plan states that VW
25 would utilize television to expand the audience and

1 familiarize the audience with ZEVs, and outdoor
2 advertising such as billboards or consistent signage at
3 charging stations to show the benefits of ZEVs and
4 charging infrastructure. Digital media, experiential
5 programs, and partnerships with other entities are
6 proposed to further deliver different parts of the
7 message.
8 One example given by the Plan is that television
9 may be used in phase 1 to raise the overall ZEV awareness,
10 while on-line digital media could be used in subsequent
11 phases to disseminate more specific messages and deal with
12 particular issues associated with ZEVs.
13 VW describes plans for experiential initiatives
14 like ride-and-drive events under Public Access
15 Initiatives. In the National Plan, ride-and-drives are
16 considered Public Access Initiatives. California,
17 however, cease sees these activities as public awareness
18 building activities and not access activities.
19 --o0o--
20 AIR RESOURCES ENGINEER LIDICKER: That concludes
21 our summary of VW's ZEV Investment Plan submittal. I'll
22 talk now about how we will go about evaluating the plan.
23 ARB staff is soliciting public comment and
24 direction from the Board on the evaluation of the VW ZEV
25 Investment Plan for consistency with the goals and terms

1 of Appendix C. ARB will approve or disapprove the plan,
2 in whole or in part.
3 Key metrics of the evaluation process will
4 include the plan's adherence to the requirements set forth
5 in the 2 liter consent decree.
6 Quickly, some of the consent decree requirements
7 for what must be included in the Plan are:
8 The plan should include a description of all
9 investments.
10 It should detail how each investment makes
11 progress toward one or more of the goals of the consent
12 decree.
13 EV charging should be able to service all ZEVs
14 with nonproprietary connectors.
15 ZEV investments should not be concentrated in a
16 single area of the State.
17 Investments cannot include research and
18 development.
19 The plan must address charging station
20 maintenance.
21 The plan must include charger implementation plan
22 details, a description of how VW will monitor and
23 maintaining each ZEV investment, the anticipated
24 creditable costs associated with each project, and an
25 estimated schedule for implementing each investment in

1 six-month intervals.
2 --o0o--
3 AIR RESOURCES ENGINEER LIDICKER: Other key
4 metrics to evaluate the plan include those laid out in the
5 Guidance document sent to VW containing further
6 information to be included in the plan and provided
7 information regarding ZEV investment opportunities that
8 are consistent with the objectives and criteria set forth
9 if Appendix C. The Guidance reflects the public input
10 received through late 2016. These include the following:
11 Early, visible progress.
12 Projects that are transformational.
13 EV infrastructure that includes multiple unit
14 dwellings, workplace, public, and long-range sites.
15 Investments be complimentary and additional.
16 Programs prioritize disadvantaged, low-income,
17 and disproportionately impacted communities.
18 Investments include business competition and
19 conduct considerations, including a self-sustaining model.
20 That the Awareness campaign include
21 multi-lingual, multi-cultural elements.
22 Access in Green Cities that prioritize
23 disadvantaged communities and track performance.
24 That Data collection and reporting is important
25 and expected.

And encouragement of hydrogen infrastructure investment.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: After ARB has approved the ZEV Investment Plan, VW has a lot of work to do in a short time frame.

VW has to coordinate the site selection process with input from multiple stakeholders including state agencies, local authorities, and site hosts.

After that will be site permitting and the negotiating and signing of up to hundreds of contracts.

In short, VW will have to spend at an unprecedented rate for an extended period of time.

--o0o--

AIR RESOURCES ENGINEER LIDICKER: This slide reviews the timeline and the process for ARB's eventual decision on the VW ZEV Investment Plan.

The Draft plan was posted on March 14th. Public comment was also opened on this same day with a notice on the website and an invitation for public comment via listserv.

A legislative hearing was held on March 21st and the ZEV Investment Plan has been presented to the Board today.

The public comment period will close April 10th,

1 almost a month after it opened.
2 Briefings for various entities such as
3 legislators and interested Board members will be held, and
4 the target dates for preparing and issuing the decision is
5 late April.
6 --o0o--
7 AIR RESOURCES ENGINEER LIDICKER: But the process
8 does not end once a ZEV Investment Plan is approved. VW
9 will present to ARB staff every six months on its
10 progress, as well as submit written reports to ARB
11 annually.
12 VW has requested ongoing coordination with state
13 and local agencies. The goal is to collaborate on site
14 selection, dialogue with utilities, and help with
15 permitting and easement efficiencies.
16 Working with state agencies will provide
17 additional oversight and help the projects complement the
18 state's investments, and afford the opportunity to ensure
19 project implementation meets the state's goals, especially
20 for investment in disadvantaged communities. ARB's new
21 Assistant Executive Officer for Environmental Justice is
22 expected to be part of this group.
23 Additionally, an independent third-party auditor
24 will provide annual reports on spending and accounting for
25 all projects related to the Plan.

1 And just with you think it's time to rest --
2 (Laughter.)
3 AIR RESOURCES ENGINEER LIDICKER: -- there will
4 be ZEV Investment Plan 2, then the 3rd, and finally the
5 4th over the next 10 years. ARB will main a public and
6 transparent process throughout this 10-year investment
7 period.
8 --o0o--
9 AIR RESOURCES ENGINEER LIDICKER: The investments
10 to be made by VW are coming at a critical time, as the ZEV
11 market ramps up in the coming years. These programs and
12 services have the potential to be transformative and
13 highly supportive of California's efforts to grow the ZEV
14 market and broaden the reach of electrified transportation
15 to all Californians, include those in disadvantaged
16 communities. Beyond California, this commitment by VW has
17 the potential to support additional ZEV markets critical
18 to the overall success of ZEV transportation.
19 Finally, we look forward to keeping the Board
20 informed about the VW ZEV Investment Commitment.
21 Thank you for the opportunity to provide this
22 update.
23 CHAIR NICHOLS: Okay. Let me just make a couple
24 comments before we get started with the witnesses.
25 First of all, I think we're going to invoke the

1 two-minute rule from the beginning here --
2 (Laughter.)
3 CHAIR NICHOLS: -- with 45 people who want to
4 comment. And the amount of comment that's been included
5 already in this process, I don't think we need to have the
6 three minutes from everyone.
7 However, that doesn't mean that we're not going
8 to be hearing from you; because as you can tell, this is a
9 long process. We're going to be with -- we're going to be
10 with this plan for many, many years. And that's a good
11 thing. But we want it to begin in as strong and
12 successful a way as we possibly can.
13 This is -- it's going to be an interesting
14 relationship.
15 I want to make sure that two things are clear.
16 First of all, I don't want to have this Board having to
17 hear every change in the plan, every adjustment in the
18 amount of money that's going to one category or another or
19 every issue that comes up with respect to a project. I
20 expect we'll be hearing from our constituents, you'll be
21 hearing from people on an ongoing basis. We're going to
22 want to be informed. And ultimately I suppose, at least
23 somewhere along the way before we get to the end of the
24 first period, we're going to want to audit, in effect, the
25 expenditures. And I want to be sure from staff that

1 that's your understanding, that we're going to be in a
2 position to do that.
3 I see head nodding, but I just want that to be
4 clear. Because right now what we're looking at is a
5 proposed expenditure plan, which has a fair amount of meat
6 on the bones, but still has a lot of missing detail which
7 will have to be developed in order for them to actually
8 spend the money.
9 Having had conversations with company in, you
10 know, recent weeks, I'm convinced that they are moving
11 fast and smart to figure this out.
12 But we're not going to be sitting back here in a
13 month, you know, line by line going through the
14 expenditure plan.
15 So Mr. Ayala or Mr. Corey, do -- or Ellen,
16 whoever.
17 Ms. Peter.
18 CHIEF COUNSEL PETER: Yes, Chair Nichols. In
19 terms of your request for the audit, built into the
20 consent decree is a third-party reviewer that we approved.
21 And that reviewer will go out and check on the different
22 aspects of it when -- including the money, including the
23 installation since we have on-the-ground checking. We
24 didn't want to take that on ourselves. That's not what we
25 do. But they at their expense has to go out and confirm

that these things are actually being built.

One of the questions that had come up before in other charging situations is maintenance. We've had people come in over the years talking about things not being maintained. In the consent decree, maintenance is required. And this is one of the things that the third-party reviewer will collect that kind of data. So we were trying to design a program, seeing problems we've seen before, build that in, and then also make Volkswagen pay for reviewer to go check that data. So that's built in. Every six months there's a report back to ARB, a meeting at least once every six months. There's annual reports; those would be made public, including the third-party reviewer and the audit. So we want to make sure the money's going where it's supposed to go.

CHAIR NICHOLS: Okay. Thank you.

With that, let's start with our list, and begin with Larry Greene from the Sacramento Air Quality Management District.

MR. GREENE: Thank you. Thank you, Chairman Nichols and members of the Board. I'm pleased to be here and have this opportunity to testify on behalf of my board and our collaborative partners in the Sacramento region.

We commend the Board and staff for staying the course on ZEVs and your great work on the VW case.

1 My testimony is in support of Sacramento as the
2 initial Green Cities location. I guess that's a surprise,
3 right?
4 (Laughter.)
5 MR. GREENE: Our district is part of a strong
6 network in our region. Our PEV collaborative, Take Charge
7 Sacramento, has regular meetings already to coordinate ZEV
8 efforts, and includes the city and county of Sacramento
9 sustainability managers, our fleet managers, our district,
10 SMUD, SACOG, Sac airports and other partners in our
11 region. It's already in place and prepared to help and
12 participate in the effort that -- the Green Cities effort.
13 We coordinate with and apply for grants through
14 the Air Resources Board, CEC, U.S. EPA, and DOE. We have
15 active grants for 29 EV school buses; 8 EVs and a car
16 sharing program in low-income areas; and are developing a
17 robust light-duty EFMP Program.
18 All those programs that I spoke of are directly
19 in or support our CalEnviroScreen communities in
20 Sacramento.
21 We're also collaborating with our regional
22 partners in developing and deploying hydrogen fuel cell
23 locomotive retrofits and hydrogen fuel cell Class A
24 tractors. So we have other kinds of activities that are
25 underway in our area too.

1 This program will roll out in Sacramento overlaid
2 on a robust and experienced set of partners that are ready
3 to help and participate. We will help this effort be
4 successful and look forward to the journey.
5 Thank you.
6 CHAIR NICHOLS: Thank you.
7 MR. SCHEMBRI: Thank you, Chairman Nichols and
8 Board for the opportunity to comment today and for your
9 leadership in ZEV deployment across California.
10 I'm Dave Schembri, CEO of EVgo, the largest
11 provider in the nation and in California of public
12 fast-charging services for all EV models. As of today,
13 approximately 90 percent of the State's population, or 35
14 million Californians, live within 35 miles of at least one
15 EVgo fast-charging freedom station.
16 We believe that the EV charging industry is at a
17 critical inflection point, needing a massive investment in
18 charging infrastructure. EVgo has been and will continue
19 to make investments in California and across the country.
20 But we enthusiastically welcome the $800 million in
21 California and $1.2 billions elsewhere in the U.S.
22 committed under the settlement agreement that will help a
23 broader deployment of EVs.
24 EVgo believes that this funding with the
25 oversight of the Board and active participation of a broad

array of private sector EV charging service providers and suppliers will be critical to making widespread EV adoption possible.

Cycle 1 of the California ZEV Investment Plan is critical to ramping up an effort that focuses on public charging infrastructures in cities and highways while also laying the groundwork for sustained funding over the life of the settlement.

Drivers want EV charging to be easy, accessible, and affordable. EVgo is one of many private-sector participants seeking to do just that. And the bulk of those industry representatives believe that the additional capital into the sector through Cycle 1 will definitely help that effort.

So in conclusion: And we're committed to fulfilling the vision of public charging infrastructure for all. We support Cycle 1 and look forward to continuing to work with the Board over the coming months and years to ensure that this and subsequent segments of the plan work to make EV charging accessible to all Californians.

Thank you.

DR. LANGDON: First of all, thank you for this California ZEV Investment Plan and all the great work that went into this. And thank you for letting me comment.

1 My name is Chris Langdon. I am a research
2 associate professor at the Peter Drucker School of
3 Management at Claremont Graduate University, which is
4 located nearby.
5 Our school has submitted a proposal to
6 Volkswagen, and we are a little bit concerned that
7 something may be overlooked. What we are concerned about
8 can be summed up in just one word: "Customer."
9 Peter Drucker is the father of modern management,
10 and he once famously said, "If there is one purpose in
11 business, it is to create a customer." And though we all
12 agree with this, in reality customer centricity is too
13 often an afterthought. Too often there's a great deal of
14 excitement focused only on the technology side alone.
15 And let me quickly give you two examples in
16 transportation to illustrate the point.
17 Driver assistant systems. Automakers have spent
18 lots of money on this technology. On paper, this
19 technology makes sense. It saves lives. But many
20 customers switch it off. Why? Because it beeps and
21 blinks and distracts us. The fact that the customer has
22 been an afterthought is limiting the technology.
23 And then the example of EV sales. Most people
24 don't drive more than 40 miles per day; and engineers have
25 confirmed this in many, many market tests; and therefore,

they gave their cars double and triple the range just to be safe.

And yet, hardly anybody of us is buying EVs. Why? Because we as customers have anxiety that these vehicles don't have enough range and they're not convenient enough for us.

In engineering theory, 120 miles should be more than enough. But not in consumer psychology.

And this brings me to my point: Your initiative will invest some 120 million in creating more ZEV infrastructure. Is this what is truly holding back the ZEV future?

In closing, if Peter Drucker were still alive today, he would remind us to first do the right thing and before doing it right.

So, and bad customer centricity including customer economics and consumer psychology.

Thank you very much.

CHAIR NICHOLS: No questions?

I have a question for you, Mr. Langdon.

My understanding is that you or some of your colleagues have actually submitted a research proposal to use some of the funds for that purpose.

MR. LANGDON: Yeah, we could use an existing fleet to run experiments, you know, standard academic

1 research. We try to understand how can we really make
2 this more attractive for customers. In other -- yeah,
3 sorry.
4 CHAIR NICHOLS: No, I understand. I think it's
5 very interesting.
6 I guess my question is, is that actually
7 consistent with the consent decree? Can we use it for
8 that purpose? I know the company is doing its own -- I
9 mean quite a bit of internal -- some -- presumably paying
10 for some research to be done. But I don't whether they're
11 charging it against the fund.
12 CHIEF COUNSEL PETER: So research is not a
13 credible cost. But it -- it's like the Devil's in the
14 details. I don't understand what their proposal is. I
15 don't know -- you could -- VW can spend more than 800
16 million.
17 CHAIR NICHOLS: Of course.
18 CHIEF COUNSEL PETER: So you could actually --
19 they could give access to them to the data potentially. I
20 mean, there's different ways to do it. So I can't really
21 comment one way or the other. But pure research is not
22 eligible because we didn't want to have Volkswagen
23 frankly, you know --
24 CHAIR NICHOLS: We want actual --
25 CHIEF COUNSEL PETER: We want projects on the

ground.

CHAIR NICHOLS: Stuff, stuff. But at the same time, in the plan that they submitted to us - and I believe this is in the public plan - it indicates that they've done quite a lot of analysis and modeling of where there's a need and -- as you said, that they've thought a lot about infrastructure. So the question is, if we were -- well guess I can begin and ask the question of the company, what are they thinking in terms of where they should be further asking questions.

So thank you.

MR. LANGDON: Thank you.

BOARD MEMBER SHERRIFFS: Can I -- along those lines though, there is money in the settlement for public education and awareness. And this would certainly -- I mean, that's the implication of this, which is so important. It's great to have highlighted that. I don't know if research per se is going to fit in. But there clearly is money in the settlement, yes, for public awareness and outreach.

CHAIR NICHOLS: Okay. Thank you.

All right. Next.

MR. GROSS: Good afternoon, Chair Nichols and Board members. My name is Tom Gross with Southern California Edison.

1 Edison appreciates the opportunity to speak on
2 the first draft of the California Zero-emission vehicle
3 Investment Plan. Edison supports efforts to increase the
4 availability of electric vehicle infrastructure. We
5 recognize that zero-emission technology is essential to
6 the attainment of the national ambient air quality
7 standards and the State's GHG goals.
8 Electric vehicles with their storage capabilities
9 have the added benefit of allowing for greater utilization
10 of renewable energy.
11 The Volkswagen Zero-emission Vehicle Investment
12 Plan has a number of elements that have already been
13 articulated. And Edison supports these ideas as a part of
14 the plan. The State investor-owned utilities, as directed
15 in SB 350, have submitted applications to the CPUC for a
16 variety of electrification projects; some for light-duty
17 vehicles, others for heavy-duty projects. But there's a
18 great need for additional infrastructure and there's ample
19 space for both the investor-owned utilities projects and
20 the VW plans articulated here.
21 SCE looks forward to closely collaborating with
22 Electrify America on these important projects.
23 Thank you.
24 CHAIR NICHOLS: Thank you.
25 MS. REGE: Good afternoon, Chair Nichols and

1 members of the Board. I'm Julia Rege, Director for
2 Environment and Energy at the Association of Global
3 Automakers.
4 Global Automakers' companies sell 56 percent of
5 the vehicles purchased in California. And Global
6 Automakers has always and will continue to support that
7 all options of -- technology options will be needed to
8 achieve ZEV and climate-change goals going forward. And
9 so our companies are investing billions of dollars in
10 advanced technologies. That means plug-in hybrids,
11 battery electric, and fuel cell electric vehicles.
12 We appreciate the work that's been done to date
13 on the investment plan, but we are concerned it's too
14 narrowly focused on plug-in options. We recommend that
15 the plan include hydrogen as well and devote a portion of
16 funds specifically for hydrogen infrastructure. The
17 inclusion of this will help support this all-inclusive
18 approach that is needed going forward for a low-carbon
19 light-duty transportation fleet.
20 Thank you.
21 MR. LORD: Good afternoon. Nice to be up close
22 again today. I have a quick statement on the Volkswagen
23 Investment Plan. And my name is Michael Lord with Toyota
24 Motor North America.
25 Toyota fully supports ARB's technology-neutral

1 approach to vehicle electrification, and strongly agrees
2 with ARB's view that the VW Investment Plan should follow
3 the same principle and support the rollout of both plug-in
4 and fuel cell technologies.
5 As ARB has recognized, both battery and fuel cell
6 technologies will be critical and necessary to meet the
7 State's clean air and climate goals, and Toyota supports
8 the use of plan funds to support the market for both.
9 We believe the lack of investment in the
10 investment plan on hydrogen hurts the rollout of fuel cell
11 vehicles in relation to battery electric vehicles. By
12 failing to acknowledge the essential role that hydrogen
13 will play in electrification, not just in the light-duty
14 fleet but across the transportation spectrum, the current
15 proposal will seem to follow only one pathway, and a
16 pathway that not all manufactures are pursuing, in the
17 sense a proposal may not only fall short of being
18 technology neutral and serving ZEVs with nonproprietary
19 connectors, but also is arguably not brand neutral.
20 Toyota therefore urges ARB to work with VW to assure that
21 hydrogen is included in this and subsequent investment
22 plans.
23 Thank you.
24 MS. CHEN: Good afternoon, Chair Nichols, members
25 of the Board. I'm Patricia Chen with the countywide

1 planning department at the L.A. County Metropolitan
2 Transportation Authority, or Metro.
3 Metro is the regional transportation planning,
4 programming, construction, and transit operator authority
5 for Los Angeles County. We are located in the South Coast
6 Air Basin, which is a nonattainment area for both
7 particulate matter and ozone. With 26 percent of the
8 State's population and its registered vehicles, including
9 those affected by the settlement, to fully address the
10 Plan's goals, VW must invest significant resources in Los
11 Angeles County. We're grateful for the opportunity to
12 share a few thoughts regarding VW's public plan.
13 We support the inclusion of both community and
14 highway depots in the Plan network vision for chargers.
15 Our EV charger proposal seeks to install EV chargers at 93
16 commuter sites, with access to our rail and fixed guideway
17 customers, making over 400 million boardings per year.
18 Forty of these sites also happen to be located at
19 or near freeways. Widespread availability of chargers in
20 park-and-ride lots will encourage commuters to consider
21 acquiring electric vehicles. So we hope to be considered
22 under the plan.
23 I also want to mention that we agree with the
24 February 10th ARB guidance that transit is an important
25 element of the zero-emissions vehicle charging and

1 deployment system.
2 For our proposed battery electric upgrade of the
3 popular Orange Line busway, the on route chargers are a
4 meaningful incremental investment that can help bridge the
5 gap between current technology and operational challenges.
6 (Laughter.)
7 MS. CHEN: Okay. I wanted to just say that we
8 really appreciate the investment contemplated in
9 disadvantaged communities and also support the other
10 important proposals coming from L.A. County sponsors.
11 Thank you again for the opportunity to comment.
12 CHAIR NICHOLS: Thank you for being here.
13 MS. ADAMS: Hi. My name is Kitty Adams. I'm the
14 Executive Director of Adopt a Charger. Adopt a Charger's
15 a nonprofit organization that solicits sponsorship to
16 install electric vehicle chargers in places like national
17 parks, state parks, museums, and universities.
18 I wanted to thank CARB staff, Board members, and
19 Commissioner Nichols for leading the charge on this. I
20 think this is a wonderful opportunity. In the investment
21 plan they specifically mentioned the California State
22 Parks. I was happy to see that because it aligns with
23 Governor Brown's 2016 ZEV Action Plan that's requiring
24 charging at the parks.
25 I've been working in the park setting for --

since 2011. These are difficult areas to commercialize. The installations are very expensive. And in addition to this, these locations, these high profile destination locations, the intent is to go beyond just charging cars and educate the public. So when we can get the EV curious to engage in conversation with an actual owner, they're going to learn about the benefits of driving these cars.

Another important aspect of these chargers at the parks is it supports the greening of the fleet. It's allowing them to transition their light-duty fleet to plug-in electric vehicles.

Another important aspect to me is the 6,000 employees of the State Parks. This is low-hanging fruit when it comes to selling cars. There's actually pent-up demand with these people to purchase these vehicles.

This investment also complements the CEC grant that was awarded to Adopt a Charger in 2014 on behalf of the State Parks. Part of this we just completed a district-wide survey and we'll be able to prioritize the next round of parks to receive funding.

So thank you very much for considering the parks in this investment.

CHAIR NICHOLS: Thanks for your work.

MR. SHUMAKER: Perhaps I don't need an announcement?

1 Go ahead and start.
2 My name is Cory Shumaker. Thank you again for
3 allowing me to comment on the VW settlement. I represent
4 the California Hydrogen Business Council comprised of a
5 hundred companies.
6 Fuel cells offer a long range and fast refueling
7 capability that is not limited to light-duty vehicles, but
8 can offer -- also offer options for public transport,
9 transit, medium- and heavy-duty goods movement. And it's
10 also good to note that hydrogen is already at least 33
11 percent renewable. So I'd like to leave you with three
12 points.
13 Historically the State has been agnostic in its
14 support for technologies that offer zero tailpipe
15 emissions, which include fuel cell electric vehicles.
16 The CHBC membership voices its profound
17 disappointment in that of the $200 million first round of
18 Volkswagen investment settlement, zero dollars were
19 allocated to hydrogen fuel cell infrastructure in vehicle
20 deployment.
21 Next, by ARB's own AB 8 report projections, in
22 2020 and 2021 there will not be enough hydrogen fueling
23 stations to support the increase of fuel cell electric
24 vehicles on California's roads. Volkswagen's settlement
25 could allow for additional station buildout in time.

1 Which leads me to my third point.
2 California can not wait until the next round of
3 VW funding. Hydrogen infrastructure needs additional
4 support now. The CHBC believes that a lack of investment
5 in hydrogen infrastructure in this funding cycle will also
6 send a signal to other states, discouraging further fuel
7 cell electric vehicle adoption and limiting price
8 reduction benefits associated with higher production
9 volumes.
10 To conclude, the CHBC very much appreciates the
11 great work and immense support from the State's agencies.
12 It is mutual goal to improve the lives of Californians and
13 provide them with the choice of zero-emission vehicle
14 options. Therefore, we strongly believe that the Board
15 should require VW to submit a revised investment plan for
16 settlement moneys to be technology agnostic, provide
17 funding to help the State meet the increasing demand of
18 fuel cell electric vehicles, and to set the right example
19 for the rest of the nation to follow.
20 Thank you.
21 MR. DANGBERG: Good afternoon, Madam Chair and
22 members of the Board. My name is John Dangberg. I'm
23 assistant city manager here representing Mayor Darrell
24 Steinberg, who sends his regrets that he could not be
25 here. But he wanted me to speak on his behalf and voice

1 Sacramento's strong support for the Volkswagen Investment
2 Plan.
3 First, Sacramento is ready and has the ability to
4 deliver on this opportunity for the State and the
5 Sacramento region. This investment in Sacramento will
6 catalyze the advancement and use of ZEV technologies in a
7 manner that is rapidly scalable and transferable to other
8 areas of the State.
9 So why Sacramento? This would be a
10 transformative opportunity for the city of Sacramento and
11 our community. Sacramento is rated as one of the nation's
12 most diverse communities where people of color are the
13 majority. The CalEnviroScreen designates our
14 disadvantaged census tracts in the top 10 percent in the
15 state, and 84,000 people in Sacramento live in high
16 poverty census tracts.
17 This initiative will greatly strengthen
18 affordable clean mobility options, integrate workforce
19 development, and serve as a model for others.
20 We provide a rare opportunity to test programs
21 that can be replicated across a range of communities. And
22 as the State's capital, Sacramento is at the heart of
23 California's policymaking. Showcasing the State's capital
24 as a green city sends a strong message about the State's
25 commitment to sustainability and zero-emission vehicles.

1 Sacramento's readiness is built on our early
2 initial investments in zero-emission technologies and our
3 strong partnership with key organizations, including UC
4 Davis and other regional agency partners.
5 Among other important initiatives, work with key
6 partners resulted in our first regional EV readiness plan
7 in 2013 known as Take Charge; and a second phase is
8 currently underway.
9 While this is a good start, we are in need of a
10 concentrated investment to scale up our efforts and
11 achieve our share of statewide ZEV targets.
12 So I will conclude by saying we stand ready to
13 work with you and your staff and Volkswagen to grow the
14 market for ZEVs, test out innovative ideas that spread to
15 other areas of the State, and provide new transportation
16 options to low income residents in disadvantaged
17 communities.
18 Thank you very much.
19 MS. ROSIA-TREMONTI: Chair Nichols, members of
20 the Board. My name is Ashley Rosia-Tremonti. I'm the
21 Sustainability Manager for the city of San Diego. I
22 report directly to our city's chief sustainability
23 officer.
24 We were pleased to submit a proposal for the
25 invest -- VW investments back in January, and we are happy

today to submit comment on their first cycle investment plan.

Overall we would have preferred additional detailed justification and general transparency within the investment plan, though we are excited to see investments happening in the San Diego region. We do want to ensure that Volkswagen is taking into account local existing plans and that they are collaborating with local governments and local organizations. This will be key to the success of these individual projects.

Per example, San Diego regionally has an EV readiness plan already designed. It was developed by the San Diego Association of Governments and the Center for Sustainable Energy in collaboration with various cities, Caltrans, local labor, universities, the Port of San Diego, and others. It is unclear from the investment plan whether or not these types of plans were taken into account when identifying projects.

Continuing on with the topic -- the important topic of collaboration, I would like to call out figure 3 of the Investment Plan. It demonstrates the number of proposals submitted by region to Volkswagen. And we would like to emphasize that the number of proposals received does not necessarily indicate interest or need for EV investments. As we determined we would collaborate, the

1 City of San Diego reached out to outside organizations and
2 submitted a single proposal. So naturally we had fewer
3 proposals submitted to Volkswagen. But that does not
4 necessarily mean that we don't have the interest.
5 Through this proposal process, we have also
6 researched and determined that the city of San Diego
7 receives about one-third the amount of state funding on a
8 per-capita basis compared to other cities identified in
9 this investment plan, and 30 times less than the city
10 receiving the largest amount of state funding. We want to
11 take opportunities such as this one to close that gap and
12 see beneficial and wise investments made in our region.
13 Thank you.
14 MS. REYES: Good afternoon, Chair Nichols and
15 members of the Board. On behalf of Mayor Garcetti, I want
16 to thank the Board and Electrify America for the
17 presentation and their time, and also to thank Electrify
18 America for the positive recognition of L.A. in the
19 initial ZEV Investment Plan as being a region worth
20 receiving targeted investment.
21 L.A.'s Green City proposal came together as a
22 result of a coalition of organizations. We are the Green
23 City L.A. Coalition, and these members are here today --
24 some of the members, and will be expressing their support
25 and recommendations for why L.A. is ripe for the Green

City designation and investment.

I'm here on behalf of the city to urge Electrify America and the Board to increase investment in L.A.

The Volkswagen settlement stems from a diesel vehicle pollution. No one has been hit harder from diesel pollution than the communities in Los Angeles. In L.A. County alone it represents over half of the state's disadvantaged communities according to the CalEnviroScreen.

It says that the plan should prioritize disadvantaged communities. The plan from Volkswagen indicated that it's a secondary consideration.

Investments in cleaning our air and sustaining livable and sustainable communities will not go to waste in Los Angeles. Dollar for dollar, using funds for zero or near-zero emissions are -- off of these projects maximizes the reach of investments in transportation, mobility, and infrastructure.

L.A. is a city that knows how to accelerate these transformative programs. And we are here to help. The Mayor's office in particular will be eager and excited to work with Electrify America to make this happen within the 30-month period. We are ready. We have projects that are shovel-ready for investments.

Simply put, we believe L.A. is ground zero for

1 the next iteration of urban mobility, technology, and
2 innovation. Investments in electrification are made --
3 you know, that are made in L.A. will be leveraged and
4 maximized in ways that are unequaled throughout the State.
5 Thank you for your time.
6 MS. NORTON: Good afternoon, Chair Nichols and
7 Board members. My name is Hilary Norton and I'm the
8 Executive Director of FAST, Fixing Angelenos Stuck in
9 Traffic, and Fast Links Downtown L.A.
10 (Laughter.)
11 MS. NORTON: Yeah, imagine my job.
12 So I'm also part of the Green City L.A.
13 Coalition. We're committed to transforming the region
14 through a partnership with Metro, the City of L.A., the
15 L.A. Cleantech Incubator, and Green Commuter through our
16 Fast Link DTLA program.
17 Our zero-emission micro-transit and van pools
18 connect to a growing ZEV transit network, encouraging
19 clean air travel and serving disadvantaged communities
20 with ZEV mobility.
21 I'm here to support L.A.'s application to be
22 selected as a Green City. As Susana said, we have over
23 half of the disadvantaged communities in California
24 region. But moreover, we have most of the impressions
25 that -- in this program and the goal to make heavy impact

with measurable results. We have 25 percent of the state's population, 47 million tourists a year, and 7.8 million vehicles currently registered, larger than 45 of 50 states.

Selecting Los Angeles will positively impact both mobility and health in disadvantaged communities. Granting L.A. the designation of Green City will deliver visible and measurable results in the first 30-month rollout, showing transformational change by leveraging L.A.'s existing ZEV momentum and the investment of Measure M funds toward sustainable travel and improved air quality.

As currently a plug-in EV owner, I'm excited for the proliferation of charging infrastructure and ZEV vehicles so that I can increase my -- reduction in my carbon footprint.

L.A. as a Green City will be California's best amplifier of the power of ZEVs, and we look forward to being supported as a Green City in this round.

Thank you very much.

MR. WRIGHT: Good afternoon, CARB members. My name is Jerard Wright, BizFed's Policy Manager. And BizFed is a grassroots alliance of more than 160 diverse business associations representing 325,000 businesses that employ 3 million people in L.A. County.

1 BizFed personally is -- not -- is technically
2 technology neutral in -- in its support -- or in its
3 mission on these items. And what we want to bring to the
4 table is that we believe L.A. is well suited for investing
5 in our transportation infrastructure, because BizFed was
6 one of the key members and key supporters of Measure M,
7 because we felt we were in it to win it for our
8 environment, for our economy -- most importantly for our
9 economy, because advancement of transportation
10 infrastructure such as this would infuse our local
11 economy, improve our environment, in making L.A. County a
12 more desirable place to live, work, and grow business.
13 Thank you so very much.
14 MR. SWORDS: Good afternoon, Chair Nichols and
15 members of the Board. My name is Michael Swords and I'm
16 the Vice President of Government Relations at the Los
17 Angeles Cleantech Incubator, or LACI.
18 LACI is a nonprofit public-private partnership
19 that helps support the growth of early-stage cleantech
20 companies. We are currently supporting 44 promising
21 cleantech startups, eight of which are advanced
22 transportation companies.
23 I am here as a member of the Green City L.A.
24 Coalition to express LACI's strong support for Los Angeles
25 to be selected as one of the two Green Cities under the

1 Volkswagen settlements.
2 Los Angeles has made tremendous progress in
3 cleaning its air over the last few decades. However, we
4 still have a lot of work to do. One only needs to take a
5 short drive on our congested freeways to see that the
6 challenge is still significant.
7 The city has rightfully made the electrification
8 of its fleets a priority. The city has also done a great
9 deal to educate the public about the benefits of the
10 electrification of transportation and has created several
11 programs designed to accelerate the rollout of electric
12 transport.
13 VW's investment could be truly transformational.
14 VW's investment could help us transform that challenge by
15 getting people out of single-car ridership and into
16 ride-sharing and car-sharing options, especially in
17 disadvantaged communities.
18 The city of L.A. owns and operates its own
19 airport, port, and utility, allowing the city to move
20 faster in accelerating VW's ZEV investment.
21 The city also has shown significant commitment
22 and leadership in sustainability and has champions at all
23 levels of government, willing and eager to work with VW to
24 accomplish the ZEV infrastructure and vehicle deployments.
25 For all these reasons, we urge you to include

1 L.A. as one of the first two Green Cities as part of this
2 round of ZEV investment.
3 Thank you.
4 MS. ANDERSON: Good -- I almost said good
5 morning.
6 Good afternoon, Madam Chair and members of the
7 Board. I appreciate -- my name is Marco Anderson. I'm
8 with Southern California Association of Governments. And
9 I'm here today to express support for the city of Los
10 Angeles being selected as one of two Green Cities in the
11 State.
12 I think it's important to note a number of people
13 have already stressed the strengths of Los Angeles as a
14 city. And also I'd like to add the growth of Los Angeles
15 as a regional partner. I don't think seven years ago I
16 would have been authorized by my leadership to come here
17 and advocate for one city over another city. But as we've
18 seen, the region has grown to understand that investments
19 in Los Angeles benefit the region and as well as the
20 diffusion of technology.
21 I think the Green Cities category is about more
22 than just putting charging stations in the ground. So
23 SCAG very much appreciates the investment in the growth of
24 infrastructure, which will allow us to meet our regional
25 GHG reduction targets as well as ARB's vehicle mandate

1 targets. However, the Green Cities is about the full
2 transformation of the entire mobility ecosystem.
3 SCAG had looked extensively at vehicle
4 electrification and also about the revolution that's
5 taking place in car sharing and the future of automated
6 vehicles. If we are to ensure that automated vehicles and
7 car sharing and robo-taxis, whatever form they take, are
8 electrified, it'll require an infrastructure and it will
9 require data and technology that adapts to that
10 infrastructure.
11 The other thing I'd like to highlight is people
12 have mentioned the fact that Los Angeles has its own
13 utility and port. It also is a transit operator and it
14 also owns the curb space that Metro relies on. Adding all
15 those things together, the last thing I'd like to
16 highlight is the city agencies such as LADOT and the
17 LADWP, they've been at the table. Across the state
18 agencies programs are asking for collaboration for team
19 building. There's only so many times you can marshal
20 those teams and come in second. But we keep doing it with
21 federal grants, with statewide grants. And we're hoping
22 to be successful in having a source of funding that that
23 coalition can use to sustain itself.
24 So thank you very much for your consideration.
25 CHAIR NICHOLS: It's Bill Magavern. That's you.

1 MR. MAGAVERN: Thank you. Bill Magavern with the
2 Coalition for Clean Air.
3 I've been very impressed with ARB's response to
4 Volkswagen's criminal conspiracy. You caught them. You
5 enforced against them. You negotiated a favorable
6 settlement. And I think that the way that you're going to
7 choose to invest the resulting funds will probably follow
8 the same kind of success.
9 I also saw -- in the last couple weeks saw Ellen
10 Peter testify to two different legislative hearings on
11 this issue, and she did a superb job both times.
12 If Volkswagen's recovery from its self-inflicted
13 wounds would be to transform itself from a diesel car
14 company into an electric car company, I think that would
15 be an excellent result.
16 As we look to how they invest these funds, I want
17 to emphasize the importance of investing in disadvantaged
18 communities. I hope that they will exceed the levels that
19 are in your guidance document.
20 We came together three years ago with a number of
21 allies to start the Charge Ahead California campaign and
22 worked with Senate President Pro Tem de Leon on
23 legislation which has the goal of giving access to the
24 cleanest vehicles to those in the most disadvantaged
25 communities. So we think this source of funds is another

additional way to augment that; and not only when it comes to light duty but also to get some of the cleanest heavy-duty vehicles into those communities.

And in addition, we agree with those who have said that we think hydrogen fuel cell infrastructure should also be included in the funding.

Thank you.

MS. KINMAN: Good afternoon. I'm Michelle Kinman with Environment California Research & Policy Center, a statewide environmental organization based in Los Angeles.

I haven't had the opportunity to review the proposals submitted by other cities, but I did want to express my support for the strength of the proposal submitted by Los Angeles.

As we all know, L.A. consistently ranks as having the worst air quality in the nation. And as we all know, L.A. is an incredibly important market for vehicle electrification with a large consumer market.

The city is also the first major city to have an electric vehicle car-share pilot in disadvantaged communities. And I've had the opportunity to work with the city firsthand on the development of this pilot program and I'm greatly impressed by the mayor and the city's demonstrated leadership and commitment to an electrified future.

The city worked with a diverse stakeholder group to develop their Green City proposal, resulting in a transformative proposal that would concentrate investment on shovel-ready projects in communities that need it most: Downtown, South L.A., Boyle Heights, Wilmington, Pacoima, and LAX. These areas are some of the most disproportionately impacted by vehicular pollution and could benefit tremendously from ZEV investments.

For all of these reasons we strongly support L.A.'s application to be selected as a Green City under the Volkswagen settlement.

Thank you.

MR. TEEBAY: Good afternoon, members of the Board. Thank you for allowing me to speak. My name is Richard Teebay. I am employed by the County of Los Angeles. I have worked with members of your staff for almost two decades, and my experience, they have been committed, dedicated, helpful, and open.

Last August I spoke with some of you at the Cleantech Incubator in downtown Los Angeles. I was advocating for EV infrastructure for disadvantaged communities. And I was politely told that ARB doesn't fund EV infrastructure. As of today, you certainly influence the funding of the EV infrastructure.

It's appropriate that you're in Riverside. It

1 serves as a dramatic backdrop for the work that you've
2 done at this meeting. This region of six counties within
3 SCAG are home to 18 million of the State's population,
4 almost half. The region consistently has the worst air
5 quality in the nation, not just the State. There's a
6 significant and obvious need for accelerating the
7 transition to zero-emission vehicles.
8 The city -- or the county supports the city's
9 application to be the clean city. Think of the world
10 stage for a moment. Think about the Super Bowl in 2019.
11 Think about the Olympics in 2024. You have a really
12 wonderful opportunity to showcase what a zero-emission
13 future looks like.
14 I'd also like to remind you that in L.A. County
15 alone there were 7.8 million registered vehicles in 2015.
16 That's more vehicles than there are people in the Bay
17 Area.
18 We are a strong advocate for infrastructure in
19 this region, especially in our disadvantaged communities.
20 One quick thought, and then I'll shut up, is
21 this has been totally silent about fleet. And I would
22 love to have a question asked about the fleets and the
23 impact that they can have. I've studied two fleets, the
24 County's and Metro's, And I can speak to that.
25 CHAIR NICHOLS: So just to be clear. Electrify

1 America will be testifying. They're the last on the
2 entire list. And we're gathering questions. I'm sure
3 we'll have many questions for them.
4 MR. TEEBAY: That's fine. Thank you.
5 MR. CAZERAS: Good afternoon, Board members. My
6 name is Fernando Cazeras and I'm the California manager
7 for Climate Smart-Cities at the Trust for Public Land.
8 I'm here to express our strong support for our Climate
9 Smart-Cities partner, the City of L.A., to be selected as
10 a Green City.
11 I'm also a member of the Green L.A. Coalition.
12 While we believe as an organization that part forests and
13 natural lands are important to climate mitigation and
14 resilience. We also know that Transportation is a latter
15 source of greenhouse gases and air pollution in L.A. As a
16 native Angeleno, I also believe that L.A. is on right path
17 to overcome our transportation, air quality, and land-use
18 challenges. But I believe that we need L.A. and the
19 region to resist transformation much quicker.
20 Heat waves are expected to significantly increase
21 in the L.A. Basin, significantly worsening the
22 ground-level ozone and air pollution that already caused
23 too many asthma attacks.
24 Volkswagen's investment presents a unique
25 opportunity to make transformative change in three ways:

1 Helping Angelenos with limited resources get out
2 of car ownership and into ride sharing and car sharing is
3 transformative in its own way.
4 Converting gasoline and diesel vehicles into ZEVs
5 and building out the necessary infrastructure to support
6 those vehicles, and accelerating ZEV freight investment is
7 an area that we believe will achieve Volkswag -- will
8 enable Volkswagen and CARB to achieve the most impact for
9 the funding.
10 I also want to make a note not to get into the
11 weeds, but being in California, I really encourage you to
12 think about this multilingual education and awareness
13 campaign that Volkswagen is able to do, that we make sure
14 that it's culturally and linguistically appropriate. We
15 do have many languages in California.
16 So for these and many other reasons, I urge you
17 to select L.A. as one of the first Green Cities this first
18 round.
19 Muchas Gracias.
20 MS. OHLAND: Good evening, members of the Air
21 Resources Board. My name is Gloria Ohland and I work for
22 Move L.A., and we care deeply about sustainable
23 transportation. I know some of you know our Executive
24 Director, Denny Zane. And we're a very big, broad
25 coalition of civic leaders who were the impetus behind the

1 Measure R Transportation and Sales Tax measure in 2008.
2 And the Measure M Transportation and Sales Tax won 72
3 percent of the vote last November.
4 And I'm here as a member of the Green City L.A.
5 Coalition to urge you to invest that VW settlement money
6 in L.A.
7 Move L.A. is on a steering committee of L.A.'s
8 brand new low income EV car-share project that's opening
9 for business in two to three months; and we've begun
10 outreach in neighborhoods to drum up interest. And I was
11 at one of the meetings on Wednesday night and I was
12 sitting next to a woman who had been playing around with
13 CalEnviroScreen 3.0. And she had found some numbers that
14 made a very compelling case for why disadvantaged
15 neighborhoods in the pilot project area of our car share
16 need EV car sharing. In her neighborhood, for example,
17 the pollution burden was very high, at 92 percent, which
18 my understanding is that means that only 8 percent of all
19 the census tracts in California have more pollution than
20 her neighborhood.
21 The diesel index was 98 percent. The PM2.5 index
22 was 80 percent. And the neighborhood is very poor. 96
23 percent of households are considered housing burdened.
24 And I don't really know that much about air
25 pollution. But I do know that diesel is a toxic

1 contaminant, it contributes to NOx, and it sticks to
2 particulate matter which gets lodged in people's lungs and
3 it's probably second only to cigarettes as cause of
4 cancer.
5 And there are a lot of kids in that neighborhood
6 and there's a big community college.
7 And I know that diesel messes with low income
8 people who live near freeways and heavily traveled
9 transportation corridors with lots of truck traffic. And
10 that's almost all of L.A.'s neighborhoods.
11 So we at the Green City Coalition believe this is
12 exactly the environment that you should invest the VW
13 settlement money in.
14 CHAIR NICHOLS: Understood. Thank you.
15 It's not our money to invest though. Just again,
16 to be clear, we're not investing it. It's their money.
17 MS. OHLAND: Oh. I wish you were.
18 CHAIR NICHOLS: Sorry.
19 Okay. Please, you're done.
20 MS. OHLAND: Okay. Well,
21 CHAIR NICHOLS: Other people are waiting.
22 MS. OHLAND: The only thing I was going to say is
23 we're shovel ready in L.A. with our low-income EV
24 car-sharing --
25 CHAIR NICHOLS: Move L.A. is a great

1 organization, and we appreciate your work. Thank you.
2 MS. BARBERENA: Good afternoon, Chair Nichols and
3 members of the Board. My name is Betty Barberena and I am
4 the outreach manager for the Electric Vehicle Car-share
5 Program coming soon to Los Angeles.
6 As part of the steering committee comprised of
7 community-based organizations, SALEF, KIWA, TRUST, and
8 South L.A., we are working along with the city and Blue
9 L.A. to make sure that this innovative program benefits
10 disadvantaged communities highly affected by
11 transportation-related pollution.
12 L.A.'s vehicular pollution comes from two primary
13 factors. The fact that L.A. is the largest vehicle market
14 in the State; and our port, which is the largest in the
15 U.S. VW ZEV Investment presents the unique opportunity to
16 address these primary factors by helping people get out of
17 their single car ridership and into ride share and car
18 share, especially in disadvantaged communities.
19 The car-share program we are getting ready to
20 implement will provide low income residents of Westlake,
21 Pico-Union, Echo Park, Downtown L.A., and parts of Korea
22 Town with access to clean and reliable transportation
23 because the vehicle fleet will be 100 percent electric
24 with publicly available infrastructure.
25 The community forums we held recently showed how

ready these communities are for ZEVs and the corresponding infrastructure, and to get rid of their diesel vehicles.

Selecting L.A. as one of the first Green Cities will allow VW to maximize its impact by leveraging hundreds of millions in both public and private funding to mitigate diesel emissions in communities that need it the most, to accelerate deployment of ZEVs and the required infrastructure.

So as part of a Green City L.A. Coalition, I urge you to include Los Angeles as a Green City as part of a first round of ZEV investments to achieve maximum impact for transportation electrification and emissions reductions.

Thank you.

CHAIR NICHOLS: Thank you.

MS. HALLS: Good afternoon, Chair Nichols and members of the Board. My name is Cassie Halls and I'm a project associate at the Shared-Use Mobility Center, a technical advisor to the L.A. Department of Transportation. I'm representing the Green City L.A. Coalition.

Volkswagen's ZEV Investment Plan represents an unparalleled opportunity to foster growth of Clean Transit, EV Car Share, and other shared mobility programs. If disadvantaged communities are to be put front and

1 center, it is critical that these programs should be put
2 front and center as well.
3 Investments in EV and shared mobility go a long
4 way. Each car in an EV car-share program is rented six to
5 seven times per day, maximizing investments in EV
6 infrastructure for the greatest public benefit. It is
7 modeled that one EV car-share car can take 9 to 13 carbon
8 emitting diesel and gasoline cars off the road. Our
9 groundbreaking EV car-share pilot program funded by your
10 agency is now under construction and will launch later
11 this year in L.A.
12 This program will serve over 7,000 households,
13 over half of which are low income. Volkswagen funding
14 could help scale this program and others like it 10 to 20
15 times the current size over the next 10 years, maximizing
16 its impact on improving air quality and filling critical
17 mobility gaps in Los Angeles's poorest and most polluted
18 communities.
19 Our share and mobility action plan for L.A.
20 County calls for growing EV car share to 2,000 vehicles,
21 which could serve over a hundred thousand Angelenos and
22 could help reach our goal of taking a hundred thousand
23 cars off the road.
24 Los Angeles has made rapid strides around a wide
25 range of public-private investments in shared mobility

1 that have gained national attention.
2 In addition to the EV car share program, four
3 cities of Los Angeles have launched bike share programs in
4 the last year, and both the city of L.A. and L.A. Metro
5 are planning micro-transit --
6 CHAIR NICHOLS: Okay. Thank you. Not taking a
7 breath does not extend your time. --
8 (Laughter.)
9 MS. HALLS: Can I just say one last thing?
10 Yeah. I just wanted to say that Los Angeles is
11 the place to look, and we know how to invest in
12 disadvantaged communities.
13 CHAIR NICHOLS: Yes, you do.
14 MS. HALLS: Thank you for your time.
15 CHAIR NICHOLS: All right. And you know
16 something. I just have to say, because I'm a resident of
17 Los Angeles and I love Los Angeles. If the issue was who
18 had organized, you know, the most people to make a pitch,
19 you guys would already have won. Okay.
20 So just know that. You're doing a great job and
21 you're doing a lot of good work. So this is all good, and
22 I think it will not be a waste no matter what happens.
23 MR. CORTES: Chair Nichols, Board members, thank
24 you so much for allowing me to address you this afternoon.
25 My name is Carlos Cortes. I'm director of engineering at

1 Broadband TelCom Power. We are an AC and DC fast charger
2 manufacturer located in Orange County. We build mostly DC
3 fast chargers. We have roughly 500 DC fast chargers
4 nationwide.
5 I wanted to come in in support -- in strong
6 support of the Volkswagen ZEV Investment Plan, for a lot
7 of reasons. The first one is, every single DC fast
8 charger we have in the state of California is being
9 heavily used. That's item number 1.
10 We do have a lot of good reasons why we want to
11 install additional DC fast chargers. The first one is
12 because it's really a drop in the bucket as far as the ZEV
13 investment plan. We need so much infrastructure for the
14 one million vehicles that are mandated to be out on the
15 road, that the $800 million investment is really a drop in
16 the bucket as far as what we need for infrastructure. And
17 we can see it in the number of transactions that we get on
18 a per-charger basis in the state of California. So that's
19 number 1.
20 Number 2. We see that the ZEV Investment Plan is
21 really inclusive of a lot of different parties and a lot
22 of different systems, and we do see it as being a system
23 that can actually be utilized in underserved communities.
24 Okay?
25 And then last, and I think the critical point in

1 this whole thing is, we really have truly a
2 chicken-and-egg situation. In order to get more cars out
3 on the road, we need charging systems out on the road.
4 Right? But what we do know because we have the experience
5 in actually installing DC fast chargers, we do know that
6 DC fast chargers by themselves to date don't financially
7 pay for themselves. They don't. So we need government
8 intervention. We do need your help to push forward the
9 investment into electric vehicle charging infrastructure
10 and network so that we can get the electric vehicles out
11 on the road.
12 Thank you so much.
13 CHAIR NICHOLS: Thank you.
14 MR. ZHENG: Good afternoon, Chair Nichols and
15 Board members. Thank you for the opportunity to make a
16 statement at this hearing. My name is Kevin Zheng and I
17 work for SemaConnect.
18 SemaConnect is a leader in developing,
19 manufacturing, and delivering network EV charging
20 solutions for commercial properties in North America.
21 SemaConnect's statement is as follows:
22 The Volkswagen settlement decree represents a
23 unique opportunity to accelerate the EV market in
24 California. Expanding this market would create jobs and a
25 new economic opportunity, help California achieve its

1 climate mitigation goals, and protect the health of
2 disadvantaged communities who face the worst effects of
3 tailpipe pollution. With that as context, SemaConnect
4 strongly supports Volkswagen's first California ZEV
5 Investment Plan. We feel it successfully meets the goals
6 of the settlement decree. We urge CARB to approve the
7 plan as soon as possible.
8 Also we are concerned that the full perspective
9 of the EV charging industry has not been well communicated
10 to the policymakers and other stakeholders so far on this
11 issue.
12 Our company and our EV industry partners are
13 committed to competition and understand how the Volkswagen
14 California ZEV Investment Plan as it is currently written
15 will be beneficial to the public and the industry.
16 As you know, Appendix C of the settlement decree
17 establishes a California ZEV investment plan which
18 requires Volkswagen to invest 800 million in California
19 over the next 10 years.
20 We applaud CARB for securing this requirement as
21 part of the settlement agreement. Along with the rest of
22 the settlement, we believe that Appendix C is an effective
23 mechanism for achieving important public benefits
24 including increasing the rate of adoption of EV cars.
25 California has always been the global leader in

moving automotive market towards a cleaner, more efficient future.

CHAIR NICHOLS: Thank you. Your time is up.

MR. ZHENG: Thank you. Thank you much.

MS. ALI: Good afternoon, Chair Nichols and members of the Board. My name is Fariya Ali and I'm speaking on behalf of Pacific Gas & Electric, the PG&E in California.

We would also like to congratulate the ARB engineers on staff for their important role in actions taken to enforce emission standards.

PG&E supports the increase in electric vehicle infrastructure that the Volkswagen Zero-emissions Vehicle Investment Plan represents and we encourage expediency in approval to allow for a quick start to implementation.

The path to achieve the State's air quality and climate goals will require a major increase in electric vehicle adoption. We believe that some of the proposals in the ZEV Investment Plan will complement actions being taken by PG&E and other utilities to advance the State's EV infrastructure to support this objective.

Another opportunity will be to use greenhouse gas reduction funds for EV and infrastructure incentives in disadvantaged communities.

PG&E's recently approved $130 million EV Charge

1 Network Program is one of the largest single deployments
2 of EV charging infrastructure in the world. And we
3 recently proposed an additional $250 million to support
4 the deployment of DC fast chargers and non-light-duty
5 electric vehicle charging infrastructure.
6 Even with these investments, much more is needed
7 to meet the Governor's goal of developing EV
8 infrastructure to support one million vehicles by 2020,
9 and we hope to see more action to support this goal soon.
10 Thank you.
11 DR. REICHMUTH: Chair Nichols and members of the
12 Board. Good afternoon. My name is Dave Reichmuth. I'm
13 speaking on behalf of the Union of Concerned Scientists.
14 The VW cheating scandal is unprecedented, and
15 this settlement is critical to repair the damages done.
16 I'd like to thank the Board and VW for moving
17 this process forward quickly. We don't want to rush in
18 making these investments, but we definitely want to move
19 expeditiously. These investments need to go forward as
20 soon as possible.
21 We're still reviewing the document and we'll
22 submit written comments later. But we do agree with the
23 comments that were made in terms of the need for hydrogen
24 infrastructure, especially to achieve the brand neutral
25 ZEV infrastructure requirement of the settlement.

1 We also agree with the initial focus on DC fast
2 charging in corridors and multi-use dwellings. It makes
3 sense. But we need to make sure that we're actually
4 serving disadvantaged communities with those investments,
5 to make sure they're in the right places.
6 We'd also want to make sure that these
7 investments coordinate with other actors in this area,
8 especially utilities and charging providers. This
9 investment needs to be complementary to what else is going
10 on in the State. It's a large amount of money, but it's
11 only a fraction of what needs to be invested in terms of
12 the private and public funds. So we want to make sure
13 that this doesn't duplicate or inhibit other programs that
14 are already ongoing.
15 Thank you.
16 CHAIR NICHOLS: Thank you. We agree.
17 MR. SULLIVAN: Good afternoon, Chair Nichols and
18 Board. My name's Joseph Sullivan. I work for the
19 International Brotherhood of Electrical Workers in the
20 National Electrical contractors Association. And than you
21 for the opportunity to comment.
22 Volkswagen's investment represents a substantial
23 opportunity to support California's climate goals, benefit
24 our hardest-hit communities, and create good middle class
25 jobs.

1 Unfortunately the Cycle 1 Investment Plan fails
2 to optimize this opportunity fully. There's no
3 description of how the investment in EV infrastructure
4 will create pathways into skilled training in middle-class
5 careers, by leveraging the State's joint labor management
6 electrical apprenticeship network, by creating
7 family-sustaining jobs with good wages and benefits, by
8 hiring workforce from disadvantaged communities, low
9 income households of veterans. We can either use this
10 money for this infrastructure build-out to create
11 temporary jobs or we can create life-long careers with
12 training and family-sustaining wages.
13 Lastly, the plan doesn't outline how Electrify
14 America will ensure that the ZEV infrastructure will be
15 installed and maintained by qualified electrical personnel
16 and contractors in accordance with State law and industry
17 best practice.
18 Thank you.
19 CHAIR NICHOLS: Again, just to be raising the
20 issue here. There is no prohibition in terms of using
21 money over many of these projects towards training of
22 people who would be doing the work on them, as far as I
23 can tell anyway.
24 CHIEF COUNSEL PETER: Not that I can recall.
25 CHAIR NICHOLS: Yeah. I think it's an important

1 point though, that the opportunity goes beyond just an
2 investment in hardware or even in jobs but in really
3 multiplication if it's done well.
4 Thank you.
5 MR. SHEARS: Good afternoon. John Shears with
6 the Center for Energy Efficiency and Renewable
7 Technologies.
8 First thing I'd like to share the observation
9 that I think that you've spoiled us, CARB, and the way
10 CARB normally workshops processes. Because I do have a
11 complaint in terms of how top down and relatively opaque
12 the development process has been around these
13 investment -- this investment plan.
14 And I hope that going forward for the next round
15 we can maybe figure out how to work with Volkswagen to
16 make that a much more transparent process.
17 What I'd like to recommend in the interim is that
18 there's at least one more, if not two more, public
19 workshops. But given the timeline, we're probably looking
20 at one to air things out more. Because I'm sure all the
21 stakeholders who would want to participate so that we
22 could have a more free back and forth -- or were available
23 in the Senate oversight hearing that Ellen did a masterful
24 job at, that you couldn't watch it live.
25 So just wanted to share that observation.

1 Also disappointed -- or we're disappointed
2 about -- over hydrogen and the lack of mention in there.
3 I want to also point that work -- I work with
4 Peter Cooper at the employment training panel on the
5 employment issue. A letter was submitted, was also shared
6 with CARB staff that we need to incorporate that in as the
7 market grows because we need to have workers who can
8 facili -- work on the vehicles and the infrastructure
9 going forward, and that's got to keep pace.
10 And then, finally, I work in the Central Valley.
11 The major metropolitan areas are not the only areas that
12 have disadvantaged communities. And the most challenging
13 environment from my take because of the capacity issues
14 that are lacking in the Central Valley is that that's --
15 that's a real concern. And what I see in this investment
16 plan is it's sort of like, you know, fly over country in
17 terms of how people talk about nationally. I see the
18 valley. And what I see in this investment plan is
19 drive-through or drive-by country.
20 So if we could deal with that, that would be
21 great.
22 CHAIR NICHOLS: Thank you.
23 MR. MUI: Simon Mui, NRDC. First, thank you to
24 your staff and all of you for bringing light to what has
25 been a dark chapter in the auto industry in terms of the

1 scandal here.
2 We did want to reinforce that we like what you're
3 doing in terms of making sure that the VW investments are
4 complementary and additional to what utilities are going
5 to do. We want to see 1 + 1 = 2 and not 1 + 1 = 1.5.
6 And we think you are doing a good job and want to
7 encourage ARB to continue doing that to make sure that
8 those investments are complementary to what charging
9 service providers as well as utilities are doing.
10 Finally, we want to thank you as well for
11 California's role in this -- in uncovering the VW scandal
12 and really putting California in a much better place
13 versus other states. We work in those other states and
14 they are very envious of the special treatment California
15 enjoys under the consent decree terms. We're only about
16 12 percent of the U.S. market, but the consent decree
17 carves out 40 percent of the Appendix C funds for
18 California. No other state has that kind of certainty.
19 They're all clamoring for VW to come to them.
20 In sum, this is a good deal for California.
21 We do think that ARB should make sure to exercise
22 its oversight on VW's investment plan to ensure they're
23 consistent with the guidance ARB has provided in the terms
24 of the consent decree. And this is very critical, because
25 many are asking for changes. And we just want to make

1 sure that you're careful to avoid asking for modifications
2 to the proposal that could reopen this and require the
3 parties to go back to the judge, resulting in potentially
4 many years of delay in opening up this deal.
5 So in sum, thank you. We like this deal. And we
6 want to prevent it from going back to the Feds.
7 MR. WHEATLEY: Chair Nichols, members and staff.
8 Thank you very much for this opportunity, and thank you
9 for everything that you do to make California this
10 wonderful leader in terms of making the world a better
11 place to live in.
12 I am predictably going to harp on about the fact
13 that we need to be using renewable energy as the primary
14 source for our considerations around ZEV infrastructure,
15 not as an afterthought as it so often is.
16 There is a commercially available and in use
17 today transportable solar-powered electric vehicle
18 charging station which requires no trenching, no
19 foundations, and it is deployed in less than 12 minutes
20 instead of less than 12 months. It was mentioned earlier
21 by Supervisor Serna an by Dr. Sherriffs. Thank you for
22 that.
23 And you yourself, Chair Nichols, have had the joy
24 of driving on sunshine after charging your own electric
25 vehicle on one of these products. Products which, by the

way, was also delivering emergency energy to the city of Los Angeles in the event of a disaster. So that was a wonderful dual use there. Manufactured in California by a team of combat veterans and very worthy of this program.

Now, I arrived here this morning in a pretty filthy mood. In fact, I was imagining all sorts of horrible scenes from Braveheart. Not the romantic ones. And that was because yesterday I received an email which led me to believe that Volkswagen was not intending to use solar in any of their deployments of electric vehicle charging infrastructure.

However, I met with representatives of Electrify America this morning, and they assured me that that's not the case and I was wrong. And unlike William Wallace, I'm prepared to admit it when I'm wrong. So delighted to see that it isn't the case and that we are going to be doing that.

What I would like to see happen is that everything is done to encourage the use of renewable energy, both in this program and anywhere else. And specifically that nothing exists in the language or within the creditable expenses or any of the other parts of the program which might prevent it or discourage it. So please help Electrify America and help everybody else to make sure that we can drive on sunshine because that is,

1 after all, the ultimate promise of this technology.
2 Thank you.
3 MS. TUTT: Good evening, Chair, Vice Chair,
4 members of the Board.
5 CHAIR NICHOLS: It's still afternoon.
6 MS. TUTT: No, after 5:00 I think that's evening.
7 So I'm Eileen Tutt with the California Electric
8 Transportation Coalition. We've been around for decades
9 in support of electrifying everything.
10 (Laughter.)
11 MS. TUTT: So I do -- you have a handout,
12 hopefully, from the clerk. I just want to say that the
13 handout -- I'm not going to go through it -- it's quite
14 lovely though. I encourage you to read it. But it does
15 show that we -- that our assessment agrees with the CARB
16 staff assessment that the need for charging in this
17 State -- and our assessment was only up to a million
18 vehicles, which by the way is nowhere near where we need
19 to be. So even just getting to a million vehicles, we are
20 woefully underfunded in infrastructure. And we agree, VW
21 and, I would say, NRG together is less 10 percent of the
22 need in California just to make the one million vehicle
23 mark, which is far short of where we need to be.
24 I also want to say that I'm really excited to see
25 the outreach and education component in the Electrify

1 America. We keep talking about infrastructure, but that
2 is really, really important. I think that -- I'm really
3 looking forward to seeing what they do.
4 We're not going to pick a city for Green City.
5 But I did like what they were doing in terms of last mile
6 delivery, shared mobility and taxis. We think it's very
7 important to expedite the -- getting this money out. We
8 don't want to see another NRG.
9 And then, finally, on Appendix D - I know that's
10 not the topic - but we do want to see electrification of
11 the medium- and heavy-duty vehicle sector with that money.
12 So hope -- you'll consider that one when you're looking at
13 how to spend it.
14 Thank you.
15 CHAIR NICHOLS: Thank you.
16 MR. ASHLEY: I'll say good afternoon, Chair
17 Nichols and members of the Board.
18 CHAIR NICHOLS: I wasn't ready to face up to it.
19 (Laughter.)
20 MR. ASHLEY: So I'm Tom Ashley. I'm Senior
21 Director of Government Affairs and Public Policy with
22 Greenlots. Greenlots is a leading provider of smart and
23 electric vehicle charging software and services,
24 headquartered in the great city of Los Angeles.
25 I wish to just really emphasize to members of the

1 Board how much of an infrastructure deficit we have in
2 this State, and really in all communities and all
3 geographies across the State. I just cannot emphasize
4 enough how far behind we are and therefore how important,
5 you know, every dollar of investment is in the space, very
6 much including the proposed ZEV Investment.
7 And like many of other voices from the industry
8 that you heard before me, we really feel that we're at a
9 stage of the market where what we need to be striving for
10 more than almost anything else is to scale up where we are
11 in the market and provide opportunities across the market
12 for companies like my own and all types of different
13 communities and drivers. We very much look forward to the
14 Board's approval of the ZEV Investment Plan.
15 Thank you.
16 CHAIR NICHOLS: Mary Kathryn is next -- Mary
17 Kathryn Campbell and then Anne Smart.
18 If she's not here, then it's you, Anne.
19 Hi. Welcome back.
20 I'm going to save you at least a few seconds,
21 each one of you, by having you not introduce yourself
22 because -- or say good afternoon or good evening, because
23 we already know that. Just plunge right in.
24 MS. SMART: Thanks. Well, I'm sure you're all
25 happy to see me up here again on this topic.

1 But there's really only one issue that I would
2 like to discuss today, and that's making sure that the
3 rising VW tide lifts all California's boats.
4 It is difficult to sell a charging station in the
5 city that doesn't already have EVs on the roads or in
6 their local dealerships, and when a local driver's image
7 of a new EV is a car in an affluent suburb and not in
8 their own driveway.
9 The unprecedented $800 million could help
10 underserved communities in California reap the benefits of
11 EVs and help drive demand for automakers across the state.
12 But unfortunately, as written, VW's proposal ignores this
13 opportunity. Instead this is a business plan allowing the
14 largest automaker in the world to inject itself in
15 California's EV charging market and profit from its
16 wrongdoing.
17 Look at where VW's plan investments are going:
18 San Francisco, San Jose, Los Angeles, Sacramento, and San
19 Diego. And which are California's strongest EV markets
20 right now: San Francisco, San Jose, Los Angeles, and San
21 Diego. Where's Fresno in this plan? Where's Stockton,
22 Modesto? Where are those communities that really need ZEV
23 integration in their communities the most?
24 One of the biggest innovations in EVs is how they
25 can integrate into our community and provide benefits for

1 drivers and site owners alike. EV infrastructure is the
2 most helpful to the most people in the communities
3 themselves, not just as an off-ramp or on-ramp on a
4 highway.
5 So these highway corridors for those residents,
6 are they for the residents that live there or are they for
7 drivers just passing through on their way to the beach or
8 Tahoe? We really need to make sure that these stations
9 also per -- charge all EVs and not just the most expensive
10 models.
11 I ask that you please reject the proposal before
12 you and instead ask VW to follow its own guidance and the
13 guidance that you have before you to invest in
14 disadvantaged communities and offer grants or rebates to
15 site hosts to let them choose, not VW, the equipment that
16 they want, the business models they want, and the
17 technology they need to grow us well beyond the limited 10
18 percent that you are suggesting this market will be.
19 Thank you for your time.
20 MS. GALE: I'd like to thank Anne for her
21 comments.
22 I'll save the niceties. Central Valley Air
23 Quality Coalition.
24 I'd like to speak today about specifically where
25 this investment is being made in the State. Our biggest

1 concern is that the plan does not prioritize disadvantaged
2 communities. This Board had urged VW to dedicate a
3 significant percentage of the funds, at least 35 percent,
4 to disadvantaged, low income, and disproportionately
5 impacted communities. However, this plan does not make
6 that commitment.
7 For instance, in the San Joaquin Valley, chargers
8 are only placed alongside the highways, ignoring the
9 opportunity to invest directly into our communities.
10 Ms. Holmes-Gen from American Lung spoke earlier
11 today about the health benefits of zero-emission vehicles.
12 ZEVs save lives. So it only makes sense that we're
13 investing in the communities that need it most. And as
14 some have already said, this plan treats a lot of the
15 valley cities like drive-by communities.
16 In addition, the plan also anticipates the launch
17 of the Green City initiative to be Sacramento. And I
18 personally love the city of Sacramento. It's wonderful.
19 But we all know that that is not where the need is.
20 And I was going to launch into all the statistics
21 on why -- on how the valley is the most -- has the most
22 polluted cities in the nation and has the most
23 disadvantaged communities in the State. But I know this
24 Board knows all of those statistics and knows the need
25 that we have.

1 So in conclusion, I suggest that this Board
2 mandates a 35 percent commitment of the 45 million for EV
3 chargers to be located in disadvantaged communities. And
4 I also ask CARB to reevaluate the Green City proposals. I
5 know that the plan says that the next Green City will be
6 in a disadvantaged community. But I would hate for that
7 to be an either/or of Bakersfield and Los Angeles or
8 neither.
9 So I'd really -- I think it's important for ARB
10 not to pass up the opportunity to be investing in the
11 communities that need it most.
12 Thank you.
13 And I'd also like to say that I'd love if there
14 were 5, 10, 15 of me here today. But know that I
15 represent the 4 million people who suffer from poor air
16 quality.
17 Thank you.
18 CHAIR NICHOLS: Could we please have whoever is
19 doing the timer restart the timer. I don't know what
20 happened. But you need to change it so that Mr. Whiteman
21 gets his full time.
22 Very good.
23 MR. WHITEMAN: Shortly after the financial
24 details of Appendix C were announced late last year,
25 rather than stepping back and allowing this funding to

take our place, Tesla doubled down on its infrastructure investments announcing a 100 percent increase in the number of superchargers between end of year 2016 and end of year 2017 in order to support the rollout of the Model 3, our $35,000 sedan to be built in Fremont and due on the market later this year.

The value and need for EV infrastructure to support long distance travel can not be overstated. Several scientific and many more nonscientific poles point to the supercharger network as a major reason consumers choose to purchase a Tesla. As the EV market moves from early adopters to mainstream consumers, the need for pervasive and accessible charging stations will continue to grow.

The proposed California Investment Plan offers a robust path forward, bringing EV infrastructure to drivers where they are and taking them where they want to go.

DC fast charging is important for long distance travel and combined with level 2 workplace and community focused DC charging as outlined in the plan, EV adoption can become a reality for those lacking off-street parking or who are transient renters.

Through its own experience, Tesla can affirm the value these investments will have across the EV community. As a company famous for never advertising, we have allowed

1 infrastructure investments to be our voice in communities
2 all across the State and country. When people see EV
3 chargers in their community and, even better, when they
4 see them in use, they are more inclined to consider
5 purchase themselves.
6 We recommend the Board expeditiously approve the
7 investment plan and allow for Volkswagen to move forward
8 with its plans here in California. Since the settlement
9 funds cannot be spent to operate Volkswagen's charging
10 network, the investment plan provides Volkswagen an
11 ongoing incentive to introduce more diverse EVs into the
12 market to ensure the infrastructure is used and their
13 investment is not wasted.
14 Thank you.
15 CHAIR NICHOLS: Thank you.
16 MR. ELRICK: Thank you, Chair.
17 Because of the early investment from the Air
18 Resources Board and the Energy Commission, the commercial
19 market for fuel cell electric vehicles began in 2015.
20 This week station number 26 opened here in Riverside, with
21 numbers 27 through 30 opening in the coming weeks.
22 Retail stations are standardized. Every car can
23 use every station, and every customer can use every
24 point-of-sale system with any credit card.
25 CEC has proposed funding for 16 additional

1 stations. And if all these funded stations open as
2 planned, California will have 65 hydrogen stations
3 statewide. We've learned a few things from these
4 stations.
5 First, hydrogen stations mean business in
6 California. We're seeing hydrogen station developer
7 start-ups as well as companies moving from Europe because
8 they believe in this technology and California.
9 Second, drivers love the cars. They aren't held
10 back by range anxiety and/or cars that are too small for
11 their families. The only thing standing in the way of ZEV
12 development are refueling points.
13 We need more stations. And ARB's own analysis
14 has found that if we continue at this pace, there will be
15 more demand for fuel than supply. And if that's happens,
16 fuel cell vehicles will slow down coming to the market.
17 Customers won't buy a car if they can't fuel them.
18 Volkswagen is a member of the California Fuel
19 Cell Partnership and continues to participate in our
20 meetings. They, like most automakers, will bring a fuel
21 cell vehicle to market with -- and will benefit from a
22 growing network of hydrogen stations. They may also
23 benefit from directly investing in the station development
24 start-ups as other automakers have.
25 California has benefited from ARB's fuel-neutral

1 position and commitment to all forms of alternative
2 transportation. Because of the agency's actions, our
3 State is a world leader in the deployment of fuel cell and
4 battery electric vehicles.
5 And I want to thank the Board and its staff for
6 continuing to show their strong leadership and initiative
7 for its citizens.
8 MS. McGHEE: The ZEVs need infrastructure. I
9 suggest we make a requirement for renewable charging. The
10 technology is advanced charging. It is available. It's
11 off the grid. It further reduces emissions and is
12 actually zero-emission charging. It saves ratepayers
13 kilowatt-hour costs. The 150 and 350 kilowatt charging
14 power is not accepted in any car or medium-duty vehicle
15 today. The 50 kilowatt is broadening and it is accepted
16 and it is the future. Transit buses develop charging to
17 accept these levels due to their gross vehicle weight.
18 Most importantly, over 20 kilowatt triggers
19 kilowatt-hour demand fees, which will greatly increase the
20 cost of charging, which increases the cost of a mile.
21 Imagine this: The cost of a kilowatt-hour is absolutely a
22 benefit when compared to fossil fuels. This will
23 accelerate adoption.
24 Renewable infrastructure supports this. It saves
25 money to a ratepayer and it saves admissions. I would

like to invite a consideration. Demonstrations are needed. We still need to know more and learn more about many fleets and other types of charging patterns and behaviors. That would be some of the barriers that we're experiencing with short-range vehicles. This would be specifically well suited for many of the fleets but the inventory is just not available.

Thank you.

CHAIR NICHOLS: Thank you.

Did you have a comment?

BOARD MEMBER RIORDAN: I just wanted to say to the staff, I think you have a very thoughtful recommendation before us in the resolution that you've provided, and I'm sure that in time we are going to improve. We may have heard some things today we'd like to include. But I think, you know, this is a great beginning and I want to thank you very specifically for acknowledging the part of this resolution that says that we are encouraging and investing in activities that do not unduly interfere with or undermined established or emerging businesses. And I felt, you know, that was a key issue for me, that people had gone out on their own and, you know, had certain things before this whole thing began.

And we need to continue to encourage them and

have a whole network of people. So I wanted to thank you.

I guess you have somebody that --

CHAIR NICHOLS: We still have two more witnesses.

BOARD MEMBER RIORDAN: I didn't realize that. I thought we were finished. I wish we were finished.

CHAIR NICHOLS: That's okay. Your comment is still --

(Laughter.)

CHAIR NICHOLS: -- still applicable.

(Laughter.)

CHAIR NICHOLS: All right. We have Mr. Harvey Eder.

BOARD MEMBER RIORDAN: Oh, I didn't know.

CHAIR NICHOLS: And also Brendan Jones from Electrify America.

MR. EDER: Hello.

There shouldn't be money in this that's paid for fines, penalties. That should be something separate. And this money could be used for seed money to leverage in combination with solar for solar electric and solar hydrogen fuel cells. And it could be especially directed towards the low and disadvantaged income.

There -- thank you.

CHAIR NICHOLS: To your point, I don't think there are any monies being spent that should have been

1 penalty money. I know you're going to be back for the
2 public comment because we've already got a card. So we'll
3 hear from you again.
4 Okay. Mr. Jones. Welcome.
5 MR. JONES: Thank you. Thank you, Board,
6 Chairman Nichols, to the CARB staff and the members of the
7 audience. I'm Brendan Jones. I'm the newly appointed COO
8 for Electrify America. Previously before that I was the
9 director of electric vehicles and infrastructure for
10 Nissan and also the vice president of OEM Development for
11 EVgo.
12 I am an EV enthusiast, an infrastructure
13 specialist. I believed in the space. After a 27-year
14 automotive career, I fell in love eight years ago with
15 what I am doing; and until the day I retire, I hope I
16 never stop. I found what I like, and I love what I do.
17 In regards to Volkswagen and our newly formed
18 company, Electrify America, we'd like to thank the Board
19 and thank the audience for the very valid comments we've
20 heard today. The ones that were very nice, were
21 complimentary; and we listened in particular to the ones
22 that had a little more sharp edges on them and elbows.
23 We're going to take all of those into consideration as we
24 move forward, and we look for the Board's and CARB's
25 advice and guidance as we continue to refine the plan.

1 The plan in essence seeks to use all aspects of
2 the EV space today: The providers today, the developers
3 today, the charger manufacturers, the installers, the
4 people that are investing their time and lives in this
5 unique opportunity that we have. We are going to continue
6 to advocate, to move forward, to use all the industry
7 players. And we're also going to do it in a very
8 customer-centric way, building stations that are visible,
9 usable, and convenient to the customers that exist today
10 and will buy EVs today, tomorrow, and into the future.
11 Thank you.
12 CHAIR NICHOLS: Before you leave, I have a few
13 questions for you --
14 (Laughter.)
15 MR. JONES: I almost got there.
16 CHAIR NICHOLS: -- which I hope you'll treat as
17 friendly, because they're meant to be. They're really
18 meant to give you an opportunity to explain more of your
19 thinking.
20 MR. JONES: Sure.
21 CHAIR NICHOLS: Because I've been fortunate
22 enough to read the plan and to read the plan that you --
23 the additional information that you filed with ARB. And I
24 know there's elements of that that are not public
25 information and that can't be discussed in public.

1 But I want to give you a chance - and I encourage
2 you to do more of this going forward - to tell us a little
3 bit more of your thinking how you got to where you are.
4 So, for example, on this issue of other EV
5 infrastructure efforts that are going on, for example, the
6 investor-owned utilities, what have you done or what are
7 you thinking you will be doing in terms of coordinating to
8 making sure that you're not, you know, putting chargers on
9 opposing corners as opposed to spreading them into places
10 that wouldn't -- in theory that would need them the most.
11 That may not be the best example. But I'm thinking of gas
12 stations where...
13 MR. JONES: Understand. And I'm happy to answer
14 that more particularly because I know the red light's not
15 going to go up in front of me.
16 CHAIR NICHOLS: It's not. No, no --
17 MR. JONES: So I feel good about that.
18 CHAIR NICHOLS: -- you can answer -- you can
19 answer it fully.
20 No, seriously, you're --
21 MR. JONES: So there's an ongoing effort with the
22 company right now to reach out and explore opportunities.
23 We heard the 1 point 1 equals 2 -- 1 plus 1 equals 2.
24 Internally we call it 1 plus 1 equals 3, and how do we
25 achieve that.

1 The effort to reach out to both investor-owned
2 utilities and municipal utilities is underway. So that we
3 don't overlap but yet we complement.
4 We've heard comments from others in the room such
5 as Pacific Gas & Electric, Southern California Edison, and
6 other utilities across the country. That is a key part of
7 our rollout plan, is how do we extend the dollars they're
8 investing with the dollars we're investing simultaneously.
9 CHAIR NICHOLS: So you have no reason to want to
10 invest where they are investing if it's already going to
11 happen.
12 MR. JONES: If it's already going to happen, we
13 need to complement that investment and spread. As we
14 heard, our chief concern is looking at the real data. So
15 this investment is only 400 chargers in the state of
16 California. There's 4,000 chargers already in the state
17 of California, so it is small in comparison.
18 And also if we look at the 10 percent that says
19 this investment over its span will only hit 10 percent of
20 the goal.
21 So we have to work with everybody else and make
22 sure that those efforts are complementary, not in
23 conflict.
24 CHAIR NICHOLS: And how are you approaching this
25 issue of investing in disadvantaged communities? What's

1 your -- at this point what's your thinking about that?
2 MR. JONES: Well, there's a two-pronged approach
3 to it first. So right now we've been identified between
4 25 and 35 percent of the investments in disadvantaged
5 communities. There'll be two specific over the life of
6 the investment identified communities. Sacramento is one
7 that is our suggestion. Another a yet to be identified.
8 I think what we owe back to CARB and to the Board
9 is a better definition of where those chargers are going
10 to go and how they're going to impact the community as a
11 whole.
12 We also need to work with those communities to
13 take our investment and expand it. It takes more than
14 just what Electrify America is going to bring to the
15 table. We've heard some statements from others who are EV
16 infrastructure partners and are out there. We encourage
17 them to also work with us in those communities.
18 It's one thing for us to do it. But if we have
19 all the players doing it, we're going to have a better
20 impact. And we want to work with them, not against them,
21 to create this. And I've done that before in a previous
22 job. I think we can do it here once we get past all the
23 details, et cetera. I see a collaborative effort as the
24 best effort for the State.
25 CHAIR NICHOLS: Do you have a response to the

suggestion that you should be investing in hydrogen infrastructure as well?

MR. JONES: Oh, I'll admit at first I'm not the expert on hydrogen infrastructure. It hasn't been a focus of mine. I'm primarily an electric vehicle infrastructure evangelist.

We are looking at it, as my boss has explained to you, I think, several times. It has not been ruled out. But we don't have any firm definition or commitment or how we're going to do that yet. So it would behoove me not to say anything other than that at this time.

CHAIR NICHOLS: Okay. And I guess maybe a last question. Others may have more too. But I want to ask you -- this is obviously a first of its kind -- the first plan of its kind that I'm aware of that anyone has ever done. And it's -- so it's a little bit of a work in progress.

But how do you anticipate that future plans will be different, either in terms of the process or what they can take?

MR. JONES: Well, first I'm hoping I'm less stressed about the future plans, because this one has been very compact. I think, number one, we can learn from the planning cycle we've gone through today. We'll have more time.

1 We are building a strategy team. And the
2 strategy team's sole purpose is to begin planning for the
3 second cycle as soon as we get into the implement phase of
4 the first cycle. So that strategy team is going to reach
5 out and say first let's analyze everything we didn't like
6 about how it happened with the approval of Cycle 1. Then
7 second, we understand that more transparency -- someone
8 made the comment about opaqueness. We have to eliminate
9 both those perceptions and the reality of it both with the
10 public, with CARB, and with the CARB staff and the Board,
11 et cetera. And that doesn't mean just for California.
12 That's across the United States.
13 Then we really have to do a good job looking at
14 what all of our partners are doing, what type of
15 technology is going into the ground today. The first
16 investment takes care of a lot of EV infrastructure, Green
17 Cities. And then we have to look at what more do we need.
18 Demand charges within this State and demand charges across
19 the United States make driving an electric vehicle if
20 those demand charges were passed on to a consumer way more
21 expensive - double, triple, quadruple the price of
22 gasoline.
23 So we have to look at the investment and analyze
24 where does this opportunity allow us to mitigate demand
25 charges? Is it battery backups at each station? Is it

1 demand mitigation software? Is it working with the
2 utilities on a collaborative effort to lower demand
3 charges for consumers who drive EVs?
4 So that planning, along with doing a gap analysis
5 and looking at other investments, needs to happen early so
6 by the time we get to the Board and to CARB, that plan is
7 almost bulletproof and might need only minor modifications
8 over time.
9 CHAIR NICHOLS: How long have you been with the
10 company
11 MR. JONES: Six months.
12 CHAIR NICHOLS: Six months. Okay.
13 MR. JONES: Six months. And I had a full head of
14 hair.
15 (Laughter.)
16 CHAIR NICHOLS: How many people are there?
17 MR. JONES: So right now there's a staff of 13
18 hired from organizations such as Nissan, Greenlots, BMW
19 North America, EVgo and Nissan, G.E. -- I won't go -- give
20 you all their names. So we're bringing in EV
21 professionals who this is what they like. One thing I've
22 learned, that if you're going to be successful in this
23 space, you better like it. And while you can't make that
24 a hard hiring criteria, it is one that we are strongly
25 evaluating. You better like this space, because you'e not

1 going to get anything accomplished. And you better learn
2 to listen; because if you don't listen, it's going to be
3 much harder.
4 CHAIR NICHOLS: So before I let you go or let you
5 answer any other questions, one more question that I was
6 going to ask you, which I found just -- oh.
7 What would you say to my friends and neighbors in
8 Los Angeles who obviously feel very strongly that they're
9 doing tremendous things with EVs and they, you know, would
10 like to do more and would like to be designated by you as
11 a Green City?
12 I need to go visit the people in Los Angeles. I
13 need to get them in a room. I need to explain in detail
14 what we plan on doing and see where there's opportunities
15 to improve upon that plan. I got that as a very clear
16 message. We took notes on that. So we have to plan a
17 meeting and we have to bring all those groups together;
18 because it's about communication. There's some things
19 frankly we will not be able to do in the plan and we're
20 not going to be able to please everybody. But with --
21 still the onus on us is to communicate what we can do and
22 find ways to extend our reach. And that very much is
23 something we'll do after the great folks of the city of
24 Los Angeles brought out the horses, the bandwagon. Not
25 much ammunition in terms of weapons, but everything else.

1 CHAIR NICHOLS: Oh, yeah. It was very positive,
2 I thought.
3 Okay. Just a couple of Board members have raised
4 their hand. So it was -- Alex Sherriffs was first and
5 then it was Senator Florez.
6 So, Dr. Sherriffs, if you want to go first.
7 BOARD MEMBER SHERRIFFS: Sure. Thank you.
8 This is $300 million; and, you're right, this is
9 very fast. And I think -- and, you know, in a sense the
10 transparency, the opacity of the process, I think about
11 what this Board goes through to think about managing $300
12 million and the length of the process. It's daunting what
13 you've been working with.
14 You know, I guess one thing I'm concerned, we've
15 heard about hydrogen and we have tried to be very fuel
16 neutral and, you know, you say it hasn't been ruled out.
17 I think we would like to hear it's in.
18 And if -- you know, it's great that you have
19 surrounded yourself with people that have passion about EV
20 and about electrification. But hydrogen is not going to
21 be on the radar if there aren't people -- their passion
22 about that as well.
23 So that's -- that's -- that's a concern.
24 This is very minor but kind of -- and then I
25 don't know if this is probably in the settlement and so

1 it's neither here nor there, and maybe it's a little bit
2 negative. But, you know, rather than saying "sponsored
3 by," I think what it should say is "Funded by VW
4 Settlement Decree," which carries I think an important
5 message. And I'm happy to see that spread everywhere.
6 The comments have been made about our valley, the
7 Central Valley. And we're only 10 percent of the
8 population. But similar to California getting 40 percent
9 of the settlement, well, in part that's because where the
10 most damage was done was in California when we look at
11 South Coast, Central Valley, the biggest impact of every
12 pollution molecule in terms of how that reverberated. And
13 so, likewise, the Central Valley may be only 10 percent.
14 But I hope in future plans there's a lot more attention to
15 the Valley. And in part, you know, the Valley, they
16 weren't here, L.A. was here. That's great. L.A. had some
17 wonderful ideas. And I hope, I hope Bakersfield, Fresno
18 are here with some wonderful ideas for the second plan.
19 You know, we want this plan to succeed. We want
20 this plan to succeed. We want this to work. You know, I
21 suppose one concern I have is it may pick off a lot of the
22 low-hanging fruit in terms of what other people have been
23 working on, what other groups have been struggling with.
24 So, again, we want it to succeed. There's -- we want it
25 to work.

1 But the complementarity is so important, so
2 critical, to be partnering with the organizations that
3 have been committed and doing so much in the past.
4 So again, you know, one of my major concerns is
5 to be sure that the Central Valley is very much on the
6 radar in subsequent plans.
7 There was an earlier comment, "Yeah, we need to
8 move forward, we need success." So, maybe not doing very
9 much with this first proposal. But, boy, we sure need to
10 look at these issues for the subsequent spending plans.
11 CHAIR NICHOLS: Okay. Senator Florez, followed
12 by Ms. Mitchell.
13 BOARD MEMBER FLOREZ: Mr. Jones, thank you for
14 joining us.
15 So you've been doing this for about six months;
16 correct?
17 MR. JONES: For Electrify America, that's
18 correct.
19 BOARD MEMBER FLOREZ: Yeah. So I guess my
20 question is, were you at our ARB meeting when we went over
21 our criteria in December?
22 MR. JONES: The original criteria meeting, no, I
23 was not in attendance for that meeting.
24 BOARD MEMBER FLOREZ: And were you able to attend
25 the legislative hearing that Ms. Peter went through the

other day at the Capitol?

MR. JONES: No. I received all the notes on the legislative hearing though and read over them.

BOARD MEMBER FLOREZ: Okay. Well, thank you for joining us today.

The reason I asked the question is, obviously you heard a lot today about the 35 percent for disadvantaged communities. In your comments you mentioned 35 percent and 25 percent. And I could see you have a little confusion. In our original PowerPoint presentation in December there was a 25 percent number there. It has been the Board's policy I believe to try to be at 35 percent for disadvantaged communities.

So I'm wondering, where does that criteria specifically fall within the way you made your decisions on this plan?

MR. JONES: So the criteria for --

BOARD MEMBER FLOREZ: 35 percent.

MR. JONES: -- the 35 percent came first as a -- from the guidance document. And when we saw the guidance document, it was the first time we have seen that. We have been working backwards since that date to ensure that where the infrastructure's going to go there's a degree of compliance if not outright compliance with that. We're in the process right now of continuing to refine that. And

1 we have new documentation that further defines, but it's
2 not available to the Board yet.
3 BOARD MEMBER FLOREZ: Got it.
4 MR. JONES: So I think on that topic, we have to
5 have a continuation of a dialogue.
6 BOARD MEMBER FLOREZ: Okay.
7 MR. JONES: I can't commit today of where we'll
8 be on a percentage, because, frankly, it's in flux and
9 it's in motion right now.
10 BOARD MEMBER FLOREZ: Well, that's my -- let me
11 just follow your train of thought then.
12 So you mentioned three words when you gave your
13 opening comment. You said, "Advice, guidance, and
14 refinement," and you just said the same thing again now.
15 So is it safe to say that the document that we have before
16 us today is not complete?
17 MR. JONES: No, it's -- the document is complete
18 in terms of where the investments are going to go. In
19 terms of what those investments --
20 BOARD MEMBER FLOREZ: So how does the 35 percent
21 fit in that then?
22 MR. JONES: Because the analysis wasn't 100
23 percent complete and did all of those chargers fit in if
24 you use the CalEnviroScreen, how much impact, where was
25 the -- when -- there's a geospatial analysis --

1 BOARD MEMBER FLOREZ: No, I get it.
2 MR. JONES: -- that goes in --
3 BOARD MEMBER FLOREZ: I get it.
4 MR. JONES: -- as well. We've just completed our
5 first round on the geospatial analysis, and that even
6 refines it further to say whether it was in. If this
7 particular charging station is in or without, and that
8 refinement is happening right now.
9 BOARD MEMBER FLOREZ: Okay. So when the
10 refinement occurs, will it be for this plan before us --
11 because we say yes or no to it. We don't like write out
12 what we'd like you to do. We simply say yes or no.
13 So I guess my questions is, so if I was looking
14 at 35 percent -- let's just use one of your metrics in
15 your plan. So 75 million for the highway. 25 percent is
16 what you utilized. But if you look at 25 percent of 75
17 million, which is of 200 million, it's about 9 percent
18 that actually go to the lowest quartile of disadvantaged
19 communities. 9 percent. Our standard here has always
20 been 35 percent. So we are severely behind in that
21 metric. And if I were to double it to go to 50th
22 quartile, we'd be at 18 percent.
23 If I were to take the highest number, 75 percent,
24 obviously we'd be at 36 percent.
25 I mean, I guess the point is we -- the way that

1 you have given us your rendition of our guidance leads me
2 to the conclusion that we are not close to the 35 percent
3 at all, which would leave me against the plan, quite
4 frankly; because I think the goal of it is to try to
5 maximize the 35 percent.
6 So let me just go a step further on timing from
7 your perspective. So let's say that Dr. Sherriffs is
8 correct -- and I think you would agree, we just kind of
9 rushed through this, right? I mean, we've had -- we put
10 our plan out. You replied in 10 days or so. And then we
11 are now seeing your plan for 10 days. And then staff told
12 us in their presentation somewhere about the end of April
13 we're supposed to say yes or no. That gives another 20
14 days.
15 So the way I look at it, it's a very fast process
16 for a lot of money, as Dr. Sherriffs said. Normally the
17 Board on that amount of money we'd take a little more time
18 to really kind of think about the metrics. But what's
19 interesting about it is in the next tier, the second
20 decree, are things I really like. So we have our EJ --
21 assistant EJ director involved. We have a target. We're
22 specifically pointing to a disadvantaged community in
23 totality, not as some sort of subsidiary off-highway
24 thing. We are pointing specifically to the
25 CalEnviroScreen. So there's some really like cool stuff

as we start to work out this second decree that I guess we may have learned moving through the first.

So I guess my question is, are we slowing you down or are we slowing ourselves down to just put both together with the same criteria?

MR. JONES: Wow. There was a lot of great content in what you said, and I don't know that I can provide you at this point in time with an adequate response. I mean, I'm not trying to brush off at all.

I think from our perspective, we have to look at the consent decree and the mandates of the consent decree, look at the guidance which we are taking seriously in looking at the guidance, and look at the plan. And that actively is taking place right now, and we're committed to that.

I can't commit to you there's going to be a hundred percent matchup to what the guidance was and what the consent decree mandates. I can commit to you that we're going to take measures to make sure that where possible the chargers will be in those areas. And there's going be no effort on behalf of Electrify America to modernize or not place them there if it meets the plan.

So there's business considerations afoot and also there is social and policy questions afoot, and we're taking all those into consideration.

1 BOARD MEMBER FLOREZ: Okay.
2 MR. JONES: And I'm not trying to be evasive.
3 BOARD MEMBER FLOREZ: No, no.
4 MR. JONES: It's a difficult question.
5 BOARD MEMBER FLOREZ: That's fine.
6 Just a last question just in terms of the timing
7 as you see it. This is a very fast process. We -- the
8 staff took us to the timeline. If you do the days, it's
9 like every note is 6 or 7 or 10 days, and maybe there's a
10 30-day public participation.
11 The reason you saw Genevieve here from the
12 Central Valley as being one of the only EJ folks here is
13 because, when you talk to EJ folks and you tell them about
14 the settlement, they go, "What's going on?" And that
15 tells me there's not enough input, there's not enough
16 discussion, there's not enough dialogue, there's not
17 enough meetings. That means the EJ community should be
18 front and center. I can definitely tell you this room
19 would be filled with outrage if they knew somehow they
20 were part of a, you know, the one I-5 stop off of Harris
21 Ranch, and you had to drive there from Avenal for 30
22 minutes or you had to drive there from Hanford for 30
23 minutes, or you had to drive from Buttonwillow down to the
24 Bakersfield -- I mean.
25 So those are questions that EJ groups I know will

1 have very serious -- want to have some serious discussions
2 on.
3 But I guess to the point of the timeline, the
4 last question I was going to ask you is -- you mentioned
5 the word " complement ." And we have heard a lot in our
6 discussions here in the Board, even at the first
7 presentation about, you know, giving you some sort of
8 competitive advantage in terms of the other companies that
9 are operating in this space. And I was very happy to hear
10 you say complement, because I think that's exactly what
11 the Board would like to do. But I think sometimes when we
12 complement, we kind of pile on in areas where there's a
13 lot of competition and where some of those areas are
14 rather well served, even though they need to grow.
15 Sacramento needs to grow. San Francisco needs to grow,
16 L.A. needs to grow. San Diego needs to grow. They're all
17 big urban centers where all of you folks are going to rush
18 in and hopefully do great jobs of getting the EVs
19 connected.
20 But when I think of the VW issue, I think about
21 sending you to places what you normally wouldn't go, you
22 know, places where you might want to think about
23 interconnective -- interconnecting some communities that
24 might be ignored.
25 So that's just kind of my thought process. So as

1 you start to think about that in the second tier or the
2 second consent decree, I think that's probably what I'd be
3 interested in hearing some of VW's thoughts.
4 The last point is, on the complement side, are
5 you coordinating with PUC in the short process? I mean,
6 it seems like we a had a lot of directive to you in our
7 own directive we put out to -- that you coordinated with
8 PUC, CEC. A lot of folks are putting infrastructure in.
9 How has that conversation gone thus far in these
10 30 days that you've seen the plan?
11 MR. JONES: So there is coordination on the
12 utility level, the depth and nature of it. I have another
13 senior director who handles that specifically. I get the
14 higher level feedback. And if I could recite all the
15 emails and the depth of those emails, I -- I wish I could.
16 And 10 years ago I might have been able to do better than
17 I can do today as well.
18 But I can tell you that I'm confident where it is
19 today, but I'm also cautious of the fact that it needs to
20 get much better.
21 BOARD MEMBER FLOREZ: Got it.
22 MR. JONES: There is newer meetings on the
23 calendar that are coming with the CPUC. I just read one
24 today; and myself and my colleague sitting back were
25 commenting on it.

1 So those efforts are ongoing, and they're also in
2 California and across the United States simultaneously.
3 BOARD MEMBER FLOREZ: Since I have you here, the
4 last -- the last question, I promise.
5 Is there a problem with combining the approach
6 that we're taking in the second decree as opposed to what
7 we're doing with the first? In other words, does it slow
8 you down if you feel that somehow you kind of got it right
9 a little more so on the second decree in terms of
10 disadvantaged communities, of involvement of our assistant
11 EJ director, involvement of CalEnviroScreen, of targeting
12 of both large and small communities where you have urban
13 centers and urban -- metropolitan centers combined with
14 communities, as you put, at least we have, you know,
15 500,000 and below as one of the criteria for you. I'm
16 just -- does that -- I guess the question is, what's the
17 drop deadline for VW for this plan? When does it not work
18 for you?
19 MR. JONES: For Cycle 1?
20 BOARD MEMBER FLOREZ: No, Cycle 1 and 2.
21 MR. JONES: Well, Cycle 1 I believe based on
22 where we're at, the consent decree was signed on October
23 26th, I believe. The clock started on January 1st. We're
24 already behind before we began.
25 BOARD MEMBER FLOREZ: And when you say we're

1 behind, why are we behind?
2 MR. JONES: There's a level of synchronicity
3 between the EPA plan and between the CARB plan.
4 BOARD MEMBER FLOREZ: Uh-huh.
5 MR. JONES: We have confidence that the CARB plan
6 is moving forward on time. We have concerns because we're
7 all still having a lot of debate that we're going to be a
8 little bit more delayed.
9 As the comment relates to the second cycle, I
10 think the second cycle gives us an opportunity to be more
11 clear and more up front in the early stages of planning on
12 what the differences are; and the differences are in
13 expectations. I can't sit here and commit to everything
14 that you're outlining. We have to look at what the
15 marketplace first yields from the first investment plan
16 when it is approved and then begins the implementation
17 phase. And we'll look at where the unmet expectations
18 were and can under the consent decree and the way its
19 established, written and the way we have to adhere to it,
20 do we have the ability to do everything that everyone
21 wants, the entire constituency group, under Cycle 2.
22 We're clearly not going to do everything. But there are
23 three more cycles to go.
24 BOARD MEMBER FLOREZ: Correct. And I just hope
25 you look at the 35 percent. That's really critical.

1 Thank you.
2 VICE CHAIR BERG: Senator Florez, I thought it
3 would be helpful too. Staff has a couple of comments on
4 the timing as well.
5 And so Ellen Peter.
6 CHIEF COUNSEL PETER: Thank you, Vice Chair Berg.
7 So, Senator Florez, just to give a little bit of
8 the timelines. You're talking about the second
9 agreement -- the first agreement and the second agreement.
10 So the one that was first signed by the -- that
11 we negotiated and was already approved by the Court, which
12 was the 2 liter deal. So all of the 800 million is in
13 that agreement. And that was negotiated in the spring of
14 2016 and signed and filed with the Court at the end of
15 June.
16 So at that point we had built in the
17 disadvantaged community as a concept as one of the
18 agreements. At that point, the figure that we used for
19 the CalEnviroScreen was the -- connected with the
20 Greenhouse Gas Reduction Fund. So that was SB 535. So in
21 the spring of 2016 that was set at 25 percent.
22 And so that was the second 2 liter deal that was
23 filed.
24 Then when you referring to the second decree when
25 we started negotiating it in the summer and fall of 2016,

at that point the legislature did two things that were significant in terms of my looking at this, is they had put in a lot of money into the budget for the EFMP Plus Up, specifically for low income people getting ZEVs. And so we -- we're in the negotiations for the next deal. And so the 25 million was basically reflecting that signal from the legislature for that program.

No more money was added into the investment. That was still at 800 million from the beginning.

The other thing, what happened that summer was AB 1555 came in, which for the Greenhouse Gas Reduction Fund went up to 35 percent. So we reflected that percentage in the ARB guidance; but just in terms of the order, they were happening at different times.

And also in that 3 liter agreement, that's when we added the second Green City, with the emphasize that it would be a disadvantaged city. So I think -- you're right. Those concepts change between the 2 liter agreement and the 3 liter agreement, and partially it was reflecting what was happening in the legislature.

BOARD MEMBER FLOREZ: Right. And if the Board liked the second part better than the first, could we not just not approve this plan and have that plan 1 and 2 re-reflective of what you just said?

CHIEF COUNSEL PETER: So they're under an

1 obligation, which was, you know, set in October of 2016,
2 to start moving. And they submitted the plan and they're
3 following all of the deadlines. In terms of that's a
4 30-month cycle.
5 And so we can look at it. And what the plan is
6 in light of the concept decree and our guidance, if they
7 chose to, you know, add more in, they could do that. But
8 there's a tension I think in terms of timing and get the
9 money out the door.
10 Also the 30-month cyc -- the 30-month plan has
11 six-month check-ins and annual reports. So I think Mr.
12 Jones indicated that he was -- they were continuing to
13 look at it. So perhaps there's a process that's already
14 built in the consent decree for touch basis back where you
15 can -- we can -- the issues that you raise, which are from
16 the 3 liter decree, those concepts could be put in. But
17 the investment comes out of the 2 liter deal --
18 BOARD MEMBER FLOREZ: Thank you.
19 CHIEF COUNSEL PETER: -- if that's helpful.
20 MR. JONES: And, Senator, my colleague handed me
21 a document that is outlining some of new work and
22 analysis, and we'll make sure the Board gets it.
23 But the round-up is -- over 35 percent of the
24 investment will fall in areas in the bottom 2 quartile.
25 Now, we owe you more definition on that and we'll

1 work to get it. I want to make it more than just a
2 statement on a piece of paper, and rather something that's
3 meaningful for the staff and for the Board.
4 BOARD MEMBER FLOREZ: Uh-huh. 35 percent in the
5 bottom 2 quartile?
6 MR. JONES: That is correct.
7 BOARD MEMBER FLOREZ On the first --
8 MR. JONES: First investment.
9 BOARD MEMBER FLOREZ: On the first investment?
10 MR. JONES: Yeah, based on the initial analysis, yeah.
11 BOARD MEMBER FLOREZ: But 75 million of 200
12 million total is 35 percent. So you're saying all the 75
13 million is going to the bottom 2 percent quartile?
14 MR. JONES: No, it's specifically on the type of
15 investment instead of the total investment. So an
16 infrastructure investment, so it --
17 BOARD MEMBER FLOREZ: Now you'd do it, it's going
18 to have to add up to 75 million, just so you know.
19 There's no other way around it. It's 35 percent. Okay.
20 MR. JONES: We'll definitely have to allow a line
21 on math, on, you know, what -- is it out of the pure total
22 or the percent that is infrastructure only versus
23 awareness versus Green City? Yes, agreed.
24 CHAIR NICHOLS: Okay. So can we hear from Ms.
25 Mitchell now please.

1 BOARD MEMBER MITCHELL: I'll try make this
2 shorter than Senator Florez.
3 But first thing was, and some of my colleagues I
4 think agree on this, that no hydrogen fueling is in the
5 plan. And I'd certainly like to see some of that. The
6 hydrogen cars are just now coming out, and we need to give
7 a boost to that market. So I think that would be
8 important for you to consider including that. I mean, it
9 is an electric motor and run by hydrogen.
10 So That would be an important component.
11 The other thing I want to mention is that I
12 represent the South Coast Air District, and that's a
13 nonattainment air district. And it would be my conclusion
14 that the VW diesel cars probably contributed a lot to the
15 NOx problem that we suffer in the South Coast District.
16 And to that degree, I think you could consider that some
17 of the funds that you have in this pot should be going to
18 mitigate that damage.
19 And I'll give a shout out to L.A. as the next
20 Green City you choose. And that would be one of the
21 reasons that I think it would be a good choice. But it
22 certainly also has a lot of disadvantaged communities
23 where you could find ways to spend that money.
24 But, anyway, NOx is a big problem for us. And VW
25 actually exacerbated that. So we would hope you would pay

1 attention to that district.
2 Thank you.
3 CHAIR NICHOLS: Okay. Supervisor Serna.
4 BOARD MEMBER SERNA: Thank you, Chair.
5 So I certainly appreciate the fact that you've
6 been up here now for probably 30 minutes asking some
7 important -- addressing some important questions,
8 especially those that come from my colleague, Senator
9 Florez.
10 But I do feel like it's important at this point
11 to note the fact that the designation as the -- of the
12 first Green City deployment and, you know, obviously, as
13 the Sacramento Valley member of this Board, I'm delighted
14 to see that VW is proposing Sacramento for its first
15 deployment. But I think it's important to realize that
16 it's not just one aspect of a particular candidate Green
17 City that you're looking at.
18 I think it's pretty clear, especially in the
19 guidance document, that there are several different
20 contributing factors that will, you know, go into the mix
21 of making that determination. And as was stated by
22 Assistant City Manager John Dangberg, who was here on
23 behalf of Mayor Darrell Steinberg, the fact that
24 Sacramento is diverse -- extremely diverse - in fact, for
25 the last 20 years it's been noted in national media as

1 being one of the top 10 diverse municipalities anywhere in
2 the country.
3 Certainly we have some very, very disadvantaged
4 communities ourselves in not just the city but the county
5 of Sacramento. In fact, the district I represent has some
6 of the poorest census tracts anywhere in Northern
7 California.
8 So, I do appreciate that.
9 And let's not forget too that one of the most
10 important aspects of making a determination of the first
11 deployment is also the likelihood for success. And when
12 you look at what Sacramento has achieved, and has actually
13 achieved years ago - not just recently but years ago,
14 especially as it relates to our Take Charge initiative to
15 be EV ready, that was actually adopted by our Council of
16 Governments -- in fact, I was on the Board in 2013 when
17 that was adopted. And certainly as a county supervisor
18 enjoyed the deployment of that particular directive as it
19 reflects how we've actually incorporated EV readiness into
20 our county building codes and parking codes. So I think
21 complement of all these considerations, all these aspects
22 of what Sacramento has done to really prepare to be
23 successful, I think I have to believe that that is what
24 has really led Electrify America and the Green Cities
25 deployment determination to the conclusion it has in terms

of the proposal that Sacramento be that first Green City deployment candidate.

So again, while I appreciate the fact that -- certainly appreciate the fact that disadvantaged communities has to be, must be a consideration here and how EV deployment and infrastructure to accommodate deployment of EVs is an important factor, it's not the only one.

CHAIR NICHOLS: Thank you.

Okay. Mr. De La Torre, you are next.

BOARD MEMBER DE LA TORRE: You've heard from two of my colleagues about hydrogen infrastructure, and you talk about electric vehicles, we talk about ZEV. We want zero-emission vehicles. So whether it's battery electric or hydrogen fuel cell, we want them both. We want to see this play out. We don't know, you don't know. Maybe you're betting on VHS, maybe you're betting on Beta. We don't know. And so we want to play this out in both marketplaces. My gut tells me they will both be out there and they will be successful. Diesel and gasoline maybe.

So it is very important that we see a benefit from this. And we're not Blanche DuBois here. We're not relying on the kindness of strangers. We are here as a party to a settlement for something that was done that was terrible.

And so we need to have a commitment from you, Electrify America, VW, whatever entity it is, that is going to deliver what we're expecting -- what the people of California are expecting, which is zero-emission vehicles.

So that I think cannot be overstated. Because it's been said by a couple of us, but I want to make it really clear. Does that mean we're going to run to court? Maybe. Does it mean we're going to run to the people of California? Oh, yeah. We can do that.

So you will understand that in light of why we're here, the only Ronald Reagan quote that I ever use, is trust but verify. And so I will expect to see in the fairly near future something that incorporates some hydrogen infrastructure into this plan. That's a lot of money, and the bulk of it can be BEV, but we need to see something a little different as well.

Thank you.

CHAIR NICHOLS: I think "Trust but verify," it was one of Ronald Reagan's made-up Russian proverbs he liked to use, as I recall.

But, you know, I think you've heard from some of our Board members. Not everybody has spoken, but I think you can tell that there's a huge amount of interest in this program going forward.

I just want to say that I appreciate your commitment to the partnership concept. I believe based on what I've read that you want this investment to be a success. I don't usually -- I'm not usually modest about ARB's ability to do absolutely anything, but I don't know that we are the experts on how best to invest ZEV money, to be quite clear here.

I think your need as a company to succeed in this area is at least the equal of our need for you to be successful from a policy perspective. And so I really want to be open to hearing from you, you know, why you make the decisions that you make. I think that is -- if there's one thing that really emerges is there's a need for that ability for all of the interested stakeholders to be able to buy into the thinking that you have.

And so maybe we could just leave it at that for the moment. And since it is now 6 o'clock and really is evening, I'll ask if people are ready to move the resolution that we have in front of us.

BOARD MEMBER SERNA: I'd like to move the resolution.

BOARD MEMBER RIORDAN: I'll second the motion.

CHAIR NICHOLS: Okay. Without any further discussion, all in favor please say aye.

(Unanimous Aye vote.)

1 (Board Member Eisenhut not present.)
2 CHAIR NICHOLS: Opposed?
3 None.
4 And no abstentions on this one.
5 So you have a resolution from us, which basically
6 is saying staff, you go, you know, work on the details
7 here within the parameters that I think we've laid out
8 pretty clearly. Keep us posted. And be well and prosper.
9 MR. JONES: Thank you, Chairman. Thank you,
10 Board. Thank you, CARB staff.
11 CHAIR NICHOLS: Thank you.
12 VICE CHAIR BERG: Mary, we do have --
13 CHAIR NICHOLS: We have one public commenter.
14 We're required by the Bagley-Keene Act to hear from any
15 member of the public who wishes to address us on a topic
16 that was not on the agenda.
17 And we have one speaker who has signed up. He's
18 spoken on every other occasion, on every other item, and
19 in public comment.
20 I don't see him at this moment.
21 Okay. He's coming. He's making his way down.
22 VICE CHAIR BERG: Could we please just sit down
23 for one moment. That'd be really great. We have two
24 minutes.
25 CHAIR NICHOLS: You are the last speaker of the

1 day.
2 MR. EDER: Okay. I want you -- when I was cut
3 off when you were talking to each other, that there was
4 $153 million in civil penalties that was included in that
5 800 million. They don't need that money. It should go
6 for low income solar electric where they can get some
7 equity in co-ops or to actually finance public
8 transportation systems, which is used by other cities --
9 companies that need tax shelter. And been working on
10 models of that.
11 Anyway, everybody's going, so you can -- But I
12 don't think that 153 million -- I think that's in there.
13 It was in the sheet you were hanging up there. It was the
14 second "whereas" on page 4. The first above it was 41
15 million and then it said 153 million to pay civil
16 penalties.
17 And they can pay their own damn civil penalties
18 and do whatever time that they've got coming like anybody
19 else.
20 CHAIR NICHOLS: Right.
21 MR. EDER: Thank you.
22 CHAIR NICHOLS: Okay. Thank you.
23 I think we are adjourned.
24 (Thereupon the Air Resources Board
25 adjourned at 6:02 p.m.)

1 C E R T I F I C A T E O F R E P O R T E R
2 I, JAMES F. PETERS, a Certified Shorthand
3 Reporter of the State of California, do hereby certify:
4 That I am a disinterested person herein; that the
5 foregoing California Air Resources Board meeting was
6 reported in shorthand by me, James F. Peters, a Certified
7 Shorthand Reporter of the State of California, and was
8 thereafter transcribed, under my direction, by
9 computer-assisted transcription;
10 I further certify that I am not of counsel or
11 attorney for any of the parties to said meeting nor in any
12 way interested in the outcome of said meeting.
13 IN WITNESS WHEREOF, I have hereunto set my hand
14 this 10th day of April, 2017.
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16
17
18
19
20
21
22 JAMES F. PETERS, CSR
23 Certified Shorthand Reporter
24 License No. 10063
25

To: Dravis, Samantha[dravis.samantha@epa.gov]; Jackson, Ryan[jackson.ryan@epa.gov]
Cc: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: Laura Kate Bender
Sent: Mon 5/1/2017 9:53:00 PM
Subject: Comment for Docket ID No. EPA-HQ-OA-2017-0190
EPA Regulatory Reform Comment Cover Letter.pdf

Attached please find additional comments from the American Lung Association for Docket ID No. EPA-HQ-OA-2017-0190. Thank you.

AMERICAN LUNG ASSOCIATION.

Harold P. Wimmer
National President and
CEO

May 1, 2017

Samantha Dravis and Ryan Jackson
Regulatory Reform Task Force
U.S. Environmental Protection Agency
William J. Clinton Building
1200 Pennsylvania Avenue NW
Washington, DC 20460

Re: Comments on EPA actions implementing Executive Order 13777, "Enforcing the Regulatory Reform Agenda." Docket ID No. EPA-HQ-OA-2017-0190.

Dear Ms. Dravis and Mr. Jackson:

The American Lung Association appreciates the opportunity to comment on U.S. EPA's actions to implement Executive Order 13777. EPA has requested input on regulations that may be appropriate for repeal, replacement, or modification. The Lung Association urges EPA to recognize the importance of retaining and enforcing a number of lifesaving, health-science-based safeguards under the Clean Air Act. We reiterate our request that EPA extend the comment period for 60 days until July 15, 2017.

The Clean Air Act is one of the nation's greatest public health laws. The standards and safeguards adopted to implement the Act have led to significantly cleaner and healthier air for all Americans, saving tens of thousands of lives each year. These benefits will continue into the future, unless the standards and safeguards are weakened or their implementation is ignored or unfunded. **The Lung Association urges you to recognize and protect these well-established benefits** when reviewing recommendations for repeal, replacement or modification.

The Lung Association further urges you to ensure that any recommendations to alter the regulations currently in place go through a separate transparent, public and accessible review and comment process consistent with the Clean Air Act, a process that is at least as open and thorough as the process required to initially develop and adopt the regulations.

Decades of evidence show the nation has successfully reduced dangerous air pollution thanks to safeguards and standards under the Clean Air Act. Cleaner air reduces the burden on the health and the risk to the lives of millions of Americans. Cleaner air keeps them out of the emergency room and hospital and enables them to continue to attend school and work. The cost of repealing these clean air protections would be high.

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Since 1970, when a bipartisan Congress strengthened the Clean Air Act, the nation has reduced the emissions of some of the most widespread and dangerous air pollutants by more than 70 percent. At the same time, the U.S. economy grew by 240 percent, the population grew by 50 percent and the use of energy increased by 44 percent. [1]

A 2011 peer-reviewed study calculated that the steps put in place to clean up air pollution between 1990 and 2010 prevented 160,000 premature deaths in 2010, and that the annual benefit would grow to 230,000 lives saved in 2020. The study estimated every $1 spent in cleaning pollution generated $30 in benefits.[2]

The standards and safeguards that provide those benefits each included extensive reviews, including of the science and of technology, and involved a public comment process. Some went through repeated reviews, multiple public hearings and extended comment periods.

Solid science provided the foundation of this process. Published, peer-reviewed research informed decisions about complex issues in the standards and safeguards. The reviews explored the evidence based in epidemiological, toxicological, and clinical studies, using research from the U.S. and around the world. For technological requirements on sources of pollution, EPA reviewed and incorporated the best approaches and technology currently in use.

For decades, the American Lung Association has submitted comments on these proposals to EPA that express support for the need to adopt strong, protective standards to comply with the requirements of the Clean Air Act. Since many of these standards may now be under review, the Lung Association submits these comments again to discuss the abundant evidence for their need and to underscore their expected benefits. In many cases, the Lung Association urged EPA to adopt even stronger standards and safeguards for public health than EPA eventually adopted.

Below is a list of the comments attached to this document, each submitted to the previous dockets. In many, public health and medical groups have joined with the Lung Association in submitting these comments.

- Comments from Health and Medical Groups on the Midterm Evaluation of Light-Duty Vehicle GHG Emission Standards (September 26, 2016)
- Comments from Health, Medical & Nursing Organizations to EPA on Methane Information Collection Request (August 2, 2016)
- Comments to EPA on proposed revision to the Cross-State Air Pollution Rule (Feb 1, 2016)
- Health Groups Comments on Proposed Methane Standards (December 4, 2015)
- Comment From More Than 600 Health and Medical Professionals Urging EPA to Adopt Strong Methane Standards (December 4, 2015)
- Comment from national health and medical groups to EPA on the ozone standard: National Health and Medical Groups support strong ozone standard (March 17, 2015)
- Comment from more than 1,000 Health and Medical Professionals re: urging EPA to adopt most protective ozone air quality standards (March 17, 2015)
- Comment from Health and Medical Groups on EPA s Clean Power Plan (December 1, 2014)

- Health and Medical Partners' Technical Comment on EPA Carbon Pollution Standards for New Power Plants (May 9, 2014)
- Comments to the EPA on the proposed New Source Performance Standards for Wood-burning Devices (May 5, 2014)
- Tier 3 Cleaner Gasoline and Vehicles Standards with 8 health and medical groups (July 1, 2013)
- Comment from health and medical professionals: Cleaner gasoline and vehicle standards (July 1, 2013)
- American Lung Association and National Medical and Health Partners on EPA's Proposed Particle (Soot) Standard (August 31, 2012)
- Letter from individual medical and health professionals on EPA's Proposed Particle (Soot) Standard (August 31, 2012)
- Comment to the Environmental Protection Agency with environmental groups on: Proposed Mercury and Air Toxics (August 4, 2011)
- Comment to Environmental Protection Agency re: Clean Air Transport Rule (October 1, 2010)

Sincerely,

Harold P. Wimmer
National President and CEO
American Lung Association

CC: Sarah Dunham, Acting Assistant Administrator for Air U.S. Environmental Protection Agency

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1 U.S. EPA, Air Pollution Emissions Trends Data, 2016; U.S. Department of Commerce Bureau of Economic Analysis, GDP and the National Income and Product Account Historical Tables, 2016.
2 US. EPA. Benefits and Costs of the Clean Air Act 1990-2020, the Second Prospective Study, April 2011.

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Nolan, Rich
Sent: Tue 5/16/2017 5:46:09 PM
Subject: NMA's Comments -- Hope you are well. Rich
NMA Regulatory Review Submission.pdf

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BRUCE WATZMAN
Senior Vice President, Regulatory Affairs

May 15, 2017

Ms. Samantha K. Davis
Regulatory Reform Officer and
Associate Administrator, Office of Policy
U.S. Environmental Protection Agency
Mail Code 1803A
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 Fed. Reg. 17,793 (Apr. 13, 2017); Docket ID No. EPA-HQ-OAR-2017-0190

Dear Ms. Davis:

The National Mining Association (NMA) appreciates the opportunity to submit this letter in response to the U.S. Environmental Protection Agency's (EPA) April 13, 2017 *Federal Register* notice "seeking input on regulations that may be appropriate for repeal, replacement, or modification." 82 Fed. Reg. 17,793. Consistent with the directive contained in E.O. 13777, 82 Fed. Reg. 12,285 (Mar. 1, 2017), our review has focused on regulations that: (1) eliminate jobs, or inhibit job creation; (2) are outdated, unnecessary; or ineffective; (3) impose costs that exceed benefits; (4) create a serious inconsistency or otherwise interfere with regulatory reform initiatives and policies; (5) use secret science; and (6) derive from or implement other Presidential directives that have been rescinded or modified.

NMA is a national trade association that includes: the producers of most of the nation's coal, metals, industrial and agricultural minerals, the manufacturers of mining and mineral processing machinery, equipment and supplies, and the engineering and consulting firms, financial institutions and other firms serving the mining industry. Our members supply energy, metals, minerals and materials used by every sector of our economy that are indispensable for the development of technology and products that improve and sustain our way of life. Their interests span the array of regulations EPA has promulgated that impact the production, movement and use of mined products. As

such, our comments address regulations falling under the purview of numerous EPA offices whose actions weigh heavily on the upstream and downstream production and use of mined materials.

At the onset, we want to thank the administration for providing this opportunity for the regulated community to submit recommendations to reform, repeal or modify regulations that impede economic growth and job creation, place unnecessary and unrealistic burdens on our nation's employers, burden domestic energy production and reduce our ability to compete in the global marketplace.

Following are regulations that impose costs which greatly exceed tangible benefits, duplicate other federal or state regulations, lack a sound scientific basis or lack any compelling purpose or need and are inconsistent with the goals of E.O. 13783, Promoting Energy Independence and Economic Growth. We appreciate the opportunity to provide input on this matter and look forward to working with EPA to revise or eliminate these unnecessary regulatory burdens.

Sincerely,

Bruce Watzman.

National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 Fed. Reg. 17,793 (Apr. 13, 2017)

Air

1. Regional Haze
2. New Source Review
3. Ozone National Ambient Air Quality Standards
4. 1-Hour PM 2.5 National Ambient Air Quality Standards
5. Cross-State Air Pollution Rule Update
6. Mercury Air Toxic Standards (MATS)
7. Primary NO2 National Ambient Air Quality Standards
8. National Ambient Air Quality Standards in Elevated Background Environments
9. Grant of Petition for Reconsideration and Stay of 2008 Fugitive Emissions Rule
10. NSPS and NESHAP Requirements and Restrictions for Stationary Engines
11. Greenhouse Gas Mandatory Reporting Rule – Subpart FF
12. Source Determination for Certain Emission Units in the Oil and Natural Gas Sector
13. NSPS provisions as applied to nonroad engines that temporarily replace a stationary engine
14. "Once in, Always" in policy under the NESHAP program
15. Interpretation of NSPS requirements for primary copper smelters
16. NESHAP requirements for primary copper smelters
17. "Common Control" interpretation for stationary source determinations under NSR and Title V operating permits
18. "Contiguous or Adjacent" interpretation for stationary source determinations under NSR and Title V operating permitting programs
19. Reactivation Policy under NSR and Title V operating permitting programs

Water

1. Steam Electric Power Generating Effluent Limitations Guidelines and Standards
2. Draft Conductivity Methodology
3. Selenium Water Quality Criterion and Implementation Guidance
4. Clean Water Act Sec. 404 Guidance Documents
5. Clean Water Act Sec. 402 Guidance Documents
6. Interpretation of CWA Sec. 404(c) Authority
7. NPDES Updates Rule
8. Compensatory Mitigation for Losses of Aquatic Resources
9. Hydrologic Alteration Report
10. Water Quality Standards Regulatory Revisions
11. Drinking Water Standards for Beryllium

Waste

1. Toxics Release Inventory (TRI) Reporting

Uranium

1. Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings and Uranium in Situ Leaching Processing Facilities
2. National Emissions Standards for Radon Emissions from Operating Mill Tailings

AIR

Regional Haze

I) Regulation

On January 10, 2017 EPA published a final rule, 82 *Fed. Reg.* 3078, implementing the second long-term strategy to achieve "reasonable progress" toward a national of preventing future, and remedying existing, impairment of visibility in certain nation parks and wilderness areas. The new rule establishes "reasonable progress goals" that states must implement to achieve visibility improvements during the second planning period from 2018-2028.

II) Problems with the Regulation

Despite the Clean Air Act's federalism mandate, the final rule imposes unrealistic reasonable progress goals that limit the discretion afforded states as to how to implement the program. This has resulted in EPA disapproving required State Implementation Plans and alternatively imposing Federal Implementation Plans (FIPs) with more stringent and costly federal emission control requirements. These requirements will, if left unchecked, result in the retirement of several coal-fired electric generating units.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) imposes excessive costs with dubious benefit, and (2) has inhibited job creation and economic growth. EPA's preexisting regional haze program resulted in the loss of a significant number of coal-fired electric generating units and the new, revised rule, contains several changes to how EPA will approach regional haze in the future. The agencies decision to impose FIP's in Texas and Arkansas (stayed and remanded to EPA) threatened a large number of coal facilities and the attendant jobs at mines supplying coal to these units. In Texas, EPA Region VI would have required 7 additional FGD retrofits. In the West, EPA Region VII has elected to require SCR retrofits. The seven units threatened under the Texas FIP are responsible for hundreds of jobs at the mines supplying coal to the generating units. The concern centers on the use of the economic test to require additional retrofit control measures at non-BART carl-fired stations even when the current emission levels are below the glide-path required by the regulation.

New Source Review

I) Regulation

NSR is a regulatory permitting program established under Title I of the Clean Air Act and its implementing regulation in 40 CFR Parts 51 & 52. The regulations require major new sources of regulated emission and "major modifications" at existing major sources to obtain preconstruction permits and to comply with stringent case-by-case new source emission limits. For coal-fired generating units NSR review is triggered when (a) the unit undergoes a non-exempt physical or operational change and (b) the change is projected to cause a "significant" increase in annual emissions.

II) Problems with the Regulation

The NSR regulations serve as a deterrent to undertaking improvements at existing sources to restore efficiency that was lost over time through wear and tear. Under the regulation, if a major modification is projected to result in a significant increase in emissions as measured by the total annual emissions (tons/yr.) then it can trigger pre-construction permitting, including the case-by-case new source standards based on the Best Available Control Technology, a process that typically takes two years and frequently even longer for controversial projects. In the Clean Power Plan, EPA took the position that efficiency upgrades that result in lower emissions per unit of electricity produced (lbs/mmBTU) may trigger the NSR requirements because the plant may operate more hours per year after the project resulting in an increase in total tons of emissions from that unit over the course of the year. Any permit for upgrades to existing coal units would almost certainly be controversial and subject to extended permit and legal challenges which would in turn delay and increase the cost of the efficiency improvement projects.

III) E.O. 13771 and 13777 Criteria

NSR is a candidate for revision under (i) Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). The NSR Rules (1) place undue burden on the development and use of domestic energy resources; (2) have the potential to eliminate jobs; (2) are outdated and ineffective; (3) create a serious inconsistency that serves as a deterrent to improved environmental performance; and (4) offers opportunities for reduction in regulatory costs.

Key to maintaining operation of the current fleet of coal-fired electric generating units is efficiency improvements. As utilities assess future generation needs an important consideration is to ensure that all assets are performing optimally – operating as

efficiently as possible. For electric generating unit's, unaddressed inefficiency results in less unit of electricity per input unit of heat. In short, inefficiency and the inability to implement efficiency upgrades without triggering controls for all regulated air pollutants threatens coal-fired units and coal miner jobs.

Additionally, and importantly, the hurdles presented by the NSR regulations prevent the continued reduction of emissions from coal-fired units. A one percentage improvement in the efficiency of a conventional pulverized coal plants results in a 2-3 percent reduction on CO2 emissions, depending on the level of efficiency prior to the change.

To remedy this, EPA should revise several longstanding NSR issues that impose undue regulatory burdens, limit operational flexibility, and result in regulatory uncertainty and enforcement exposure for all regulated sources. For some of these issues, EPA previously developed rulemaking proposals (but never finalized them) including the following:

i. EPA "Aggregation" policy: Through a series of guidance memoranda and applicability determinations, EPA developed a case-by-case, multi-factor approach for determining whether changes over time at a source should be "aggregated" and treated as a single project for purposes of determining NSR permitting requirements. EPA's current approach is cumbersome, prone to inconsistencies, and subject to aggressive/adverse agency interpretations. While EPA developed rule revisions intended to clarify when multiple projects should be aggregated for NSR permit applicability purposes, they were never finalized.

ii. EPA "Debottlenecking" policy: Through a series of guidance memoranda and applicability determinations, EPA developed a case-by-case approach for determining whether a proposed change would "debottleneck" upstream and downstream operations and whether the associated increase in emissions at those units should be included in determining NSR permitting requirements. EPA's case-by-case approach is cumbersome, unnecessarily complicated, prone to inconsistencies, and subject to aggressive/adverse agency interpretations. While EPA developed rule revisions intended to clarify that there must be a causal link between the change and the emissions increase from upstream or downstream units, it never finalized them.

iii. EPA "Project netting" policy: EPA has inconsistently taken the position that "project netting" (considering both emission increases and decreases attributable to project) may not be considered in determining whether the project would result in a significant emissions increase subject to NSR permitting requirements. While EPA developed rule revisions intended to allow project netting, EPA published a notice indicating that it was taking no action in 2009. Subsequent EPA determinations expressly state that project netting is not currently allowed by rule

or policy, which increases the scope of projects that potentially could be subject to NSR permitting requirements thereby subjecting the regulated community to additional regulatory burdens, delay, and costs.

Ozone National Ambient Air Quality Standards

I) Regulation

On Oct. 26, 2015, the agency published a final rule that reduced the ozone NAAQS from 75 to 70 ppb, 80 *Fed. Reg*. 65,292. Under the regulation states are required to designate non-attainment areas which, once designated, require the imposition of permitting restrictions for expansion of existing facilities or construction of new facilities that will contribute to overall ozone emissions.

II) Problems with the Regulation

Adoption of the 2015 NAAQS triggered a series of ongoing implementation dates for which States and sources must plan. In addition, northeastern states and environmental groups have submitted section 126 petitions claiming coal plants in upwind states will impede attainment of the NAAQS limits. Despite extensive comments submitted during the rulemaking, the final rule largely ignored the impact of natural sources of ozone, international transport of ozone and the use of modeling versus air quality monitoring to make determinations for areas as attainment, nonattainment or unclassifiable.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) imposes excessive costs with dubious benefit, and (2) will result in job losses. While EPA estimated net benefits of the final rule of $1.5 to $4.5 billion in 2011$ an independent study conducted by National Economic Research Associates concluded that the rule would reduce GDP by $140 billion per year; result on 1.4 million few jobs at factories, mines, agricultural facilities.

1-Hour PM 2.5 National Ambient Air Quality Standards

I) Regulation

$PM_{2.5}$ primary and secondary standards were last reviewed and finalized on January 15, 2013, 75 *Fed. Reg.* 3085. The rule establishes 35 **m**g/m^3 as a 24-hour standard for $PM_{2.5}$ with a form of the standard: 98th percentile, averaged over 3 years. It also establishes an annual primary standard for $PM_{2.5}$ of 12.0 **m**g/m^3 and an annual secondary standard of 15.0 **m**g/m^3 based on an annual arithmetic mean, averaged over 3 years.

II) Problems with the Regulation

$PM_{2.5}$ standards are being used for modeling compliance that include crustal emissions such as fugitive dust, while the health-based concerns upon which the standards rely are derived from combustion emissions from fossil fuels. The supporting health studies were conducted in dominantly urban areas, where $PM_{2.5}$ emissions are predominantly derived from combustion sources. However, particulate matter emissions in more rural and remote areas are more significantly impacted by crustal material sourced from activities such as agriculture and mining. The health concerns for particulate matter derived from fugitive dust and crustal materials are appropriately addressed by the PM_{10} standards and should not be considered under compliance with $PM_{2.5}$ standards. Modelling compliance with the latest $PM_{2.5}$ standards using EPA's currently approved methodology often shows exceedances when considering crustal-derived particulate emissions from mining activities. This results in either restriction or reduction of existing mining activities that were previously permissible. Capital costs required to overcome this can also render new projects or expansions uneconomic.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) will eliminate jobs or inhibit job creation, (2) is unnecessary, and (3) imposes costs that exceed benefits. EPA should consider redefining $PM_{2.5}$ emissions as only applying to particulate matter from combustion emissions, or excluding (earth material) crustal derived particulate matter from the regulation.

Cross State Air Pollution Rule Update

I) Regulation

The Cross State Air Pollution Rule Update was finalized on Oct. 28, 2016, 81 *Fed. Reg.* 7404. The rule establishes new NOx ozone-season (May through September) budgets for fossil fuel-fired electric generating units in 23 eastern states.

II) Problems with the Regulation

While the final rule was less stringent than the proposed rule, it still poses undue burdens for a number of utilities and could affect coal production and eliminate jobs.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) imposes excessive costs exceeding any reasonable measure of projected benefits, and (3) will result in job losses. The negative impacts of the rule stem from EPA's use of a number of unreasonable analytic assumptions that bias the analysis toward finding that upwind sources are creating downwind nonattainment problems. These assumptions include, among others, the use of outdated data on emissions in upwind states and ambient pollution concentrations in downwind states and the use of a 1 percent threshold to determine whether upwind sources are meaningfully contributing to downwind impacts. EPA should grant pending reconsideration petitions and use the reconsideration process to redo the CSAPR-Update rule modeling based on more reasonable assumptions. The new modeling would likely significantly reduce the number of states that are subject to the rule and, for those states that remain subject to the rule, significantly increase their NOx budgets.

Mercury Air Toxic Standards (MATS)

I) Regulation

On Feb. 16, 2012 (effective April 16, 2012) the agency published a final rule under CAA Section 112 for new and existing coal- and oil-fired electric generating units establishing National Emission Standards for Hazardous Air Pollutants (NESHAPs) for major and areas source of HAPS (mercury, trace metals and acid gases). The rule required EGU's, within 3-years of finalization, to install pollution control equipment at many fossil-fueled power plants or retire a large number of units that cannot now be brought back on line. The rule was challenged and on June 29, 2015 the Supreme Court issued a 5-4 decision granting petitioner's request to strike down the final rule and remand the case back to the D.C. Circuit for further proceedings. Following publication of a supplemental finding EPA, on April 14, 2016, issued a final finding that it is appropriate and necessary to set standards for air toxics from coal- and oil-fired power plants. The finding has been challenged in *Murray Energy v. EPA*, Case No. 16-1127 (D.C. Cir. Apr. 25, 2016)

II) Problems with the Regulation

Despite EPA's claim that the final rule would result in the closure of 5GW of fossil-fueled electric generation coal unit retirements, based on utility reporting, by the 2015/2016 compliance deadline exceeded 50GW.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) is ineffective; and (2) imposes excessive costs with dubious benefit, and (3) will has resulted in job losses. In promulgating the final rule the agency estimated the cost of the rule to be $9.8b per year, but bring, at most, only $4-$6 million in benefits. Additionally, more than half of the cists are attributable to imposing standards for emissions the agency found pose no danger to public health. The direct jobs impacts of the rule have proven devastating for coal miners, power plant workers and other Americans formerly employed in the coal supply chain. More than 65,000 coal miners have lost their high-wage jobs since 2011 with the vast majority attributable to coal-fired power plants clotures as a result of the final rule.

The appropriate and necessary finding on which the rule is based is completely contrived and serves as a negative precedent for future action. Reconsideration would provide value by removing the reliance on a faulty "co-benefits" concept as a precedent for cost-benefit analysis and subject the science underpinning the rule to scrutiny.

Primary NO2 National Ambient Air Quality Standard

I) Regulation

Primary NO_2 standard was reviewed and finalized for the first time to include a 1 hour standard on February 9, 2010, 75 *Fed. Reg.* 6474. The rule establishes 100 ppb as a 1 hour standard for NO_2 with a form of the standard: 98th percentile, 1-hour daily maximum, averaged over 3 years.

II) Problems with the Regulation

A 1-hour low level NO_2 standard is not warranted or necessary. For example, OSHA Permissible Exposure Level for 8 hours is 5 ppm for NO_2 while even California OSHA allows an 8 hour exposure of 1 ppm NO_2. There are no specific tests to diagnose for NO_2 poisoning. So the health-based analyses that EPA relied on are based on probable symptoms and causation statistics. Furthermore, EPA proposed as part of the same rule establishing a more extensive roadside NO_2 monitoring network, indicating that they did not have enough information to really assess NO_2 effects on the populace at large. Modelling compliance with the 1 hour NO_2 standard using EPA's currently approved methodology often shows exceedances due to either conservative model assumptions and/or variations in the meteorological parameters. This results in either restriction or reduction of existing mining activities that were previously permissible. Capital costs required to overcome this can also render new projects or expansions uneconomic.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) will eliminate jobs or inhibit job creation, (2) is unnecessary, and (3) imposes costs that exceed benefits. EPA should consider removing the 1-hr NO_2 standard during the NAAQS review process that is court-ordered for a proposed rule by July 2017. If deemed necessary for health protection, alternatively EPA might consider replacing it with a 24-hour or an 8-hour standard.

National Ambient Air Quality Standards (NAAQS) in Elevated Background Environments

I) Regulation(s)

The most recent example is the Ozone Primary and Secondary standards that were last reviewed and finalized on October 26, 2015, 80 *Fed. Reg.* 65292. The rule establishes 0.070 ppm as an 8-hour standard for Ozone with a form of the standard: annual fourth highest daily maximum 8-hour average concentration, averaged over 3 years.

Another example are particulate matter standards such as $PM_{2.5}$ and PM_{10} which were last reviewed and finalized on January 15, 2013, 75 *Fed. Reg.* 3085. The rule establishes 35 **m**g/m^3 as a 24-hour standard for $PM_{2.5}$ with a form of the standard: 98th percentile, averaged over 3 years. It also establishes an annual primary standard for $PM_{2.5}$ of 12.0 **m**g/m^3 and an annual secondary standard of 15.0 **m**g/m^3 based on an annual arithmetic mean, averaged over 3 years. Furthermore, it confirms the standard for PM10 as 150 **m**g/m^3 as a 24-hour standard not to be exceeded more than once per year on average over a 3-year period.

II) Problems with the Regulation(s)

The ozone standard for example is approaching background concentrations in the Mountain West terrain that is optimal for mining activities. The elevated background concentrations are primarily driven by elevation and geography but are also further exacerbated by stratospheric intrusions, wildfires and international transport. Areas of measured elevated background concentration are in locations where no industrial or urban activities exist within the airshed.

Particulate matter standard can be exceeded periodically in many remote areas due to wind-blown dust in arid desert environments where precipitation is low and vegetation is naturally sparse.

Supporting health studies are typically conducted where there is a significant difference between background concentrations and the standard and not where the background concentration already approaches the standard due to natural conditions.

Demonstrating compliance with the latest Ozone, $PM_{2.5}$, and PM_{10} standards can show exceedances when elevated background concentrations are additive to mining activities. This results in either restriction or reduction of existing mining activities that were previously permissible. Capital costs required to overcome this can also render new projects or expansions uneconomic.

III) E.O. 13777 Criteria

These regulation(s) are candidate(s) for revision under E.O. 13771 as they: (1) will eliminate jobs or inhibit job creation, 2) are unnecessary, and (3) impose costs that exceed benefits. EPA should consider proposing alternative standards for these pollutants that allow for an increment + the background concentration or perhaps allowance for more exceedances. For example, the Ozone standard of 0.070 ppm could be allowed to have an alternative standard in an area with a background concentration of 0.065 ppm in addition to an allowable increment of 0.025 ppm which would be 0.090 ppm in that location. Another possibility: for the PM_{10} standard the alternative to the 150 mg/m^3 might be approached by allowing ten exceedances per year if the background concentration is above 100 mg/m^3.

Grant of Petition for Reconsideration and Stay of 2008 Fugitive Emissions Rule

I) Regulation

In 2008, EPA issued a rule clarifying when fugitive emissions should be considered when assessing emission thresholds for major source construction, as well as major modifications. 73 Fed. Reg. 77882 (Dec. 19, 2008) (The Fugitive Emissions Rule). The rule clarified that fugitive emissions are not to be considered when assessing thresholds for either major modifications or new construction unless the source belongs to one of the 28 listed source categories. In doing so, the rule introduced consistency and certainty into making such determinations. However, in April 2009, EPA granted a Natural Resources Defense Council petition for reconsideration and stayed indefinitely the 2008 rulemaking. *See* 74 Fed. Reg. 50115 (Sept. 30, 2009); 74 Fed. Reg. 65692 (Dec. 31, 2009); 75 Fed. Reg. 6823 (Feb. 11, 2010). EPA has not taken final action consistent with its granting the petition for reconsideration, creating substantial regulatory uncertainty regarding the treatment of fugitive emissions in major modification determinations.

II) Problems with the Regulation

Under the Clean Air Act (CAA), a source must make a threshold calculation of its potential to emit air pollutants to determine whether it is a "major stationary source" or has undertaken a "major modification" for purposes of NSR permitting requirements. EPA historically has not required sources to include fugitive emissions in the threshold calculation for new sources unless the source belongs to one of 28 source categories listed by EPA through rulemaking. (Mining operations are not included in these listed source categories.) EPA's 2009 grant of the Natural Resources Defense Council's petition for reconsideration challenging the 2008 rule raises an inconsistency with EPA's past practice that results in regulatory uncertainty for mining and other industry sectors.

III) E.O. 13777 Criteria

EPA's grant of the Natural Resources Defense Council's petition for reconsideration and the stay of the 2008 rulemaking is a candidate for revision under Executive Order 13777. EPA's approach as articulated in its decision to grant the petition for reconsideration is inconsistent with past practice, and is unnecessary and ineffective.

NSPS and NESHAP Requirements and Restrictions for Stationary Engines

I) Regulation(s)

Applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) are found in 40 CFR Part 63 Subpart ZZZZ. Applicable New Source Performance Standards (NSPS) for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) are found in 40 CFR Part 60 Subpart IIII. Applicable NSPS for Station Spark Ignition (SI) ICE are found in 40 CFR Part 60 Subpart JJJJ.

II) Problems with the Regulation(s)

Given the remote locations of typical mining operations within sparsely populated airsheds, there are minimal health benefits to be gained by restricting owner/operators from using certain stationary engines for applicable uses depending on when the engine is placed in service. Most of these engines are only utilized in an emergency backup capacity with few actual hours of operation on an annual basis. Non-emergency generators are used occasionally in more remote locations where grid power is not readily available. These requirements can mandate substantial capital expenditures to upgrade stationary engines that are fully usable and functional in areas where health impacts are negligible given their location and application.

III) E.O. 13777 Criteria

These regulations are candidates for revision under E.O. 13771 as they: (1) impose costs that exceed benefits. EPA should consider granting an exemption from or eliminating these owner operator requirements and restrictions for Stationary Engines (especially emergency generators) that are located in sparsely populated airsheds (typical for many mining operations).

Greenhouse Gas Mandatory Reporting Rule – Subpart FF

I) Regulation

On Dec. 9, 2016 EPA published a final rule, 81 *Fed. Reg*. 89188 to amend the reporting requirements for 29 subparts, including underground coal mines, to expand monitoring or reporting requirements necessary to improve verification and the accuracy of data submitted.

II) Problems with the Regulation

The reporting requirements for underground coal mines in subpart FF are not warranted or necessary. Coal mine emissions are negligible when compared to overall emissions yet the costs to be borne by the industry are grossly disproportional to any perceived benefit. The rule requires, in many instances, mine operators to utilize continuous emission monitoring systems that have not been designed for use in the underground environment.

III) E.O. 13777 Criteria

The regulation is a candidate for revision under E.O. 13771 as it: (1) imposes excessive costs with dubious benefit. According to EPA "the incremental increase in costs for subpart FF reporters from the revised monitoring requirements are $28,440 per facility in the first year (RY2018) and $14,609 in subsequent years ($2011). The proposed revisions are estimated to affect 65 respondents and would have an industry incremental cost of $1,848,571 in the first year (RY2018) and $949,582 in subsequent years. The annual hourly burden associated with these monitoring costs are 320 hours per reporter in the first year and 165 hours in subsequent years." The incremental cost increase represented a cost increase of over 3 times what underground coal mines operators incurred prior to issuance of the final rule and one member has incurred a cost increase of more than 500 percent to comply with the regulation.

Source Determination for Certain Emission Units in the Oil and Natural Gas Sector

I) Regulation

The Source Determination for Certain Emission Units in the Oil and Natural Gas Sector rule was finalized on June 3, 2016, 81 Fed. Reg. 35622 (Source Determination Rule). The rule clarifies the meaning of the term ''adjacent'' that is used to determine the scope of a ''stationary source'' for purposes of the Prevention of Significant Deterioration (PSD) and Nonattainment NSR (NNSR) preconstruction permitting programs and the scope of a ''major source'' in the title V operating permit program in the onshore oil and natural gas sector.

II) Problems with the Regulation

Historically, the determination of the scope of a stationary source has been difficult in view of the ambiguity surrounding the interpretation of the term "adjacent." The Source Determination Rule establishes definitive criteria for determining the scope of a stationary source and thereby resolving, to a significant degree, the ambiguity surrounding such determinations; however, the rule's applicability is limited to the onshore oil and natural gas industry. The rule's applicability should be broadened to cover other industry sectors and, in particular, the mining sector in view of the commonalities – operations covering large areas and ownership issues – that the mining sector shares with the oil and gas industry.

III) E.O. 13777 Criteria

The Source Determination rule is a candidate for revision under Executive Order 13777. The lack of definition or clarity for the term "adjacent" under the PSD, NNSR and tile V programs (outside of the oil and natural gas industry) is outdated, unnecessary and ineffective, and creates a serious inconsistency.

NSPS provisions as applied to a Nonroad Engine that temporarily replaces a Stationary Engine

I) Regulation(s)

Applicable New Source Performance Standards (NSPS) for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) are found in 40 CFR Part 60 Subpart IIII. Applicable NSPS for Stationary Spark Ignition (SI) ICE are found in 40 CFR Part 60 Subpart JJJJ.

II) Problems with the Regulation(s)

As part of the rulemaking for NSPS Subparts IIII and JJJJ, EPA took the position that nonroad engines (i.e., portable engines that are not used in the same location for 12 consecutive months or more) that temporarily replace a stationary engine would be considered stationary engines. EPA regulates nonroad engines and stationary engines under different regulatory programs that include prohibitions on changing status (from nonroad to stationary and vice versa) unless the engine complies with all requirements under the relevant program. As a result, sources using nonroad engines to temporarily replace an existing stationary engine (e.g., while repairs are conducted) are unnecessarily subject to stationary source permitting requirements, compliance issues, and enforcement exposure.

III) E.O. 13777 Criteria

These regulations are candidates for revision under E.O. 13771 as they: (1) impose costs that exceed benefits and (2) create a serious inconsistency. EPA should consider revising these Subparts as part of required periodic review and include necessary clarifications and corrections to address the use of nonroad engines to temporarily replace stationary engines in accordance with the respective regulatory programs.

Once in, always in policy under NESHAP program

I) Regulation(s)

The National Emission Standards for Hazardous Air Pollutants (NESHAP) are found in 40 CFR Part 63.

II) Problems with the Regulation(s)

Under the NESHAP program, EPA established a "Once In, Always In" policy that requires a source that is a major source of hazardous air pollutant (HAP) emissions on the first compliance date of a particular NESHAP standard to comply permanently with that standard even if the source subsequently lowers HAP emissions below major source applicability thresholds. Accordingly, the policy eliminates any incentive for sources to reduce HAP emissions below major source thresholds to avoid regulatory burdens and costs. While EPA developed rule amendments that would eliminate the "Once In, Always In" policy, EPA took no further action on the amendments after opponents in Congress included a rider in a 2007 appropriations bill prohibiting funding of the amendments.

III) E.O. 13777 Criteria

The "Once In, Always In" policy is a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, or ineffective and (2) imposes costs that exceed benefits. EPA should consider rescinding the prior policy through rulemaking establishing a new policy under the NESHAP program based on the prior proposal.

Interpretation of NSPS requirements for Primary Copper Smelters

I) Regulation(s)

Applicable New Source Performance Standards (NSPS) for Primary Copper Smelters are found in 40 CFR Part 60 Subpart P.

II) Problems with the Regulation(s)

Some EPA representatives have taken the position that the NSPS Subpart P emission standard applies to any emissions from an affected facility rather than those emissions exiting the control device as the achievable standard was developed (i.e., through performance testing) during the initial rulemaking. In light of this interpretation, sources subject to Subpart P are unnecessarily subject to compliance issues, regulatory uncertainty, and enforcement exposure because some smaller levels of emissions (i.e., fugitive emissions that are unable to be collected and controlled) are not amenable to compliance demonstrations through performance testing.

III) E.O. 13777 Criteria

The Subpart P regulations are candidates for revision under E.O. 13771 because as interpreted they: (1) impose costs that exceed benefits and (2) create a serious inconsistency. EPA should consider revising the Subpart P regulations as part of required periodic review and include necessary clarifications and corrections to address the appropriate compliance demonstration.

NESHAP requirements for Primary Copper Smelters

I) Regulation(s)

Applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters are found in 40 CFR Part 63 Subpart QQQ.

II) Problems with the Regulation(s)

The Subpart QQQ regulations contain several errors and ambiguities in the provisions for establishing operating parameter limits for control devices and capture systems as well as associated monitoring. Due to the errors and ambiguities, sources regulated by Subpart QQQ are subject to unnecessary regulatory burdens and costs; regulatory uncertainty; and enforcement exposure.

III) E.O. 13777 Criteria

The Subpart QQQ regulations are a candidate for revision under E.O. 13777 as they: (1) impose costs that exceed benefits and (2) create a serious inconsistency. During a required periodic review of the regulation, EPA should consider including necessary clarifications and corrections to provisions for establishing operating parameter limits for control devices and capture systems as well as associated monitoring.

"Common Control" interpretation for stationary source determinations under NSR and Title V operating permitting programs

I) Regulation(s)

The NSR permitting program requirements are found at 40 C.F.R §§ 51.165, 51.166, and 52.21. The Title V operating permit program requirements are found at 40 C.F.R. Part 70.

II) Problems with the Regulation(s)

EPA's evolving interpretations have taken the position that a contract for hire between two otherwise separate companies can establish "common control" (i.e., one of the elements for determining whether two or more operations should be considered a single source or separate sources for permitting purposes). Based on this interpretation, permitting could be required to allow the operation of temporary contractor-operated equipment and activities within an existing permitted source owned and operated by a separate company—even if the contractor's equipment and activities are already separately permitted.

III) E.O. 13777 Criteria

The "common control" interpretation for stationary source determinations is a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, or ineffective and (2) imposes costs that exceed benefits. EPA should consider rescinding its prior guidance through formal rulemaking establishing a definition of "common control" for purposes of stationary source determinations under the NSR and Title V operating permit programs. EPA should also consider issuing contemporaneous guidance on portable and temporary source permitting.

"Contiguous or Adjacent" interpretation for stationary source determinations under NSR and Title V operating permitting programs

I) Regulation(s)

The NSR permitting program requirements are found at 40 C.F.R §§51.165, 51.166, and 52.21. The Title V operating permit program requirements are found at 40 C.F.R. Part 70.

II) Problems with the Regulation(s)

EPA's evolving interpretations have taken the position that the functional relationship between two operations (rather than the physical proximity) can establish whether the operations are located on "contiguous or adjacent" properties (one of the elements for determining whether two or more operations should be considered a single source or separate sources for permitting purposes). Based on this interpretation, otherwise separate sources located miles apart could be considered part of the same source and potentially subject to more stringent permitting requirement as a single source. Although EPA's interpretation was rejected by the Sixth Circuit Court of Appeals, EPA, in guidance, indicated it planned to retain its interpretation in all areas except those within the Sixth Circuit's jurisdiction. The courts also vacated this guidance as a violation of EPA's Regional Consistency rule. Rather than accept the court's decision, EPA initiated a revision to its Regional Consistency rule. Eliminating EPA's underlying "functional relationship" test would render the litigation moot.

III) E.O. 13777 Criteria

The "contiguous or adjacent" interpretation for stationary source determinations is a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, or ineffective and (2) imposes costs that exceed benefits. EPA should consider rescinding its prior guidance through formal rulemaking establishing a definition of "contiguous or adjacent" consistent with the Sixth Circuit's decision for purposes of stationary source determinations under the NSR and Title V operating permit programs.

Reactivation Policy under NSR and Title V operating permitting programs

I) Regulation(s)

The NSR permitting program requirements are found at 40 C.F.R §§51.165, 51.166, and 52.21. The Title V operating permit program requirements are found at 40 C.F.R. Part 70.

II) Problems with the Regulation(s)

Under EPA's "reactivation" policy, sources that shut down temporarily may be considered "new" upon reactivation (i.e., restart) and subject to regulatory requirements that apply to new sources. While EPA's policy historically focused on whether the shutdown was intended to be permanent (presumed if the source was shut down for two years or more), EPA's more recent positions (e.g., that taken in EPA, *In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc.*) require a continuous demonstration of concrete plans to restart for purposes of rebutting the presumption of permanent shutdown. EPA has also imposed additional tests that could effectively require all reactivations to require permitting as a physical change or change in the method of operation (i.e., from a lengthy period of inactivity to fully operational status).

III) E.O. 13777 Criteria

The reactivation policy is a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, or ineffective and (2) imposes costs that exceed benefits. EPA should consider rescinding its prior guidance and positions through formal rulemaking that codifies a revised reactivation policy.

WATER

Steam Electric Power Generating Effluent Limitations Guidelines and Standards

I) Regulation

The Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG Rule"), which was promulgated pursuant to a settlement agreement with environmental organizations and finalized in Nov. 2015, sets novel, stringent limits on wastewater discharges from power plants under the Clean Water Act. Specifically, the rule imposes new design criteria and numeric limits directly applicable to hundreds of existing coal-fired power generating facilities, as well as even more burdensome standards for new sources.

II) Problems with the Regulation

The ELG Rule imposes excessive compliance costs and regulatory burdens on utilities, which will have serious ramifications on both the utility and coal industries and the large and small businesses that rely on them. In promulgating the ELG Rule, the Environmental Protection Agency (EPA) relied on limited and obsolete data, and withheld much of the fundamental information upon which it relied. As a result, the ELG Rule imposes requirements under a "best available technology economically achievable" standard that are not, in fact, available, feasible or economically achievable. Furthermore, many of the assumptions made in the ELG Rule were based on EPA's Clean Power Plan (CPP) and Coal Combustion Residuals (CCR) Rule, both of which are likely to undergo significant changes which will undoubtedly impact many of the premises upon which the ELG Rule was based.

According to the utility industry, the ELG Rule will force plant closures and lead in many instances to compliance costs in the hundreds of millions of dollars *per effected company*. For example, Dynegy has estimated costs associated with the ELG Rule at $308 million, MRG anticipates costs of approximately $200 million, and AEP has projected costs ranging from $400-550 million through 2023. When combined with the CPP and CCR Rule, the cumulative impacts to coal-fired electric generation are staggering.

III) E.O. 13771 and E.O. 13777 Criteria

The ELG Rule is a strong candidate for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the ELG Rule (1) eliminates jobs and inhibits job creation; (2)

imposes costs that exceed its benefits; (3) relies in part on data, information, and methods that are not publicly available or that are insufficiently transparent to meet the standard for reproducibility; (4) places undue burden on the development and use of domestic energy resources; and (5) offers opportunities for reduction in regulatory costs. Furthermore, review under the relevant E.O.s would allow the Administration the opportunity to comprehensively address the cumulative impacts of the ELG Rule, CPP, and CCR Rule to the coal mining and utility industries. The ELG Rule was based on unsound and, in many cases, undisclosed data, imposes overly stringent limitations not supported by scientific or economic realities, and will lead to excessive compliance costs and the closure of coal-fired power plants.

Draft Conductivity Methodology

I) Regulation

In late Dec. 2016, the U.S. Environmental Protection Agency (EPA) released its draft document, *Field-Based Methods for Developing Aquatic Life Criteria for Specific Conductivity*. The document is intended to provide guidance to states on developing numeric field-based conductivity criteria for flowing waters, and is based in large part on EPA's controversial work, *A Field-Based Aquatic Life Benchmark for Conductivity in Central Appalachian Streams*, which was the subject of a lawsuit brought against EPA by the National Mining Association and the states of Kentucky and West Virginia. Importantly, if finalized, states will have to consider the document in their triennial reviews of their water quality standards packages, and may be forced via EPA or outside lawsuits to adopt numeric criteria for conductivity that they do not believe are based on sound science. Additionally, environmental organizations have already pointed to the document upon which the methodology is based to force post-hoc, court-developed numeric conductivity limits which the state had specifically rejected into coal mining discharge permits.

II) Problems with the Regulation

EPA's draft conductivity methodology suffers from multiple fatal technical and scientific flaws which render the numeric limits it produces not scientifically valid. These flaws include issues associated with data collection and analysis, inappropriate application of extirpation methods and regression models, and the failure to consider multiple factors that could lead to the presence or absence of benthic invertebrates from sample streams. Additionally, the Clean Water Act (CWA) expressly provides for narrative water quality criteria, and it is up to the states to determine how to interpret such criteria – states should not be forced to develop numeric criteria that they do not feel is supported by science.

Importantly, while most coal and hardrock mining operations will have significant difficulty complying with the proposed numeric limits, those limits are so overly stringent that multiple other sectors of the economy – including, among others, agriculture, POTWs, and oil and gas operations – will have difficulty meeting them as well. Furthermore, where treatment is available to meet the proposed limits, significant costs are likely associated. Extremely low conductivity limits can often only be met through the installation of reverse osmosis (RO) technology, if at all. While the costs of RO treatment vary, an example of two municipal wastewater treatment facilities in the Indianapolis area shows that the capital costs for installation of RO technology was $700 million, and annual costs for implementation were projected at $40 million – resulting in overall annualized treatment costs of $116.9 million, assuming that capital

costs would be financed over 20 years. It should also be noted that in some instances treatment technologies might not be available to meet the proposed limits, resulting in lost job opportunities, decreased economic growth, and a failure to develop the U.S.'s vast mineral potential with no corresponding environmental benefit.

Finally, the Obama Administration announced its intention to revise the 1985 *Guidelines for Deriving Numerical National Water Quality Criteria for the Protection of Aquatic Organisms and Their Uses.* Those guidelines provide the basis for deriving EPA's national water quality criteria, and EPA has in the past noted that field-based criteria – like the conductivity methodology – will likely be a focal point of its revisions. It is therefore incredibly important for EPA to review the conductivity methodology to ensure that any field-based methods supported by the agency are technically and scientifically sound.

III) E.O. 13771 and E.O. 13777 Criteria

EPA's draft conductivity methodology is a strong candidate for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the methodology (1) eliminates jobs and inhibits job creation; (2) imposes costs that exceed its benefits; (3) places undue burden on the development and use of domestic energy resources; (4) offers opportunities for reduction in regulatory costs; and (5) intrudes upon the rights of states. The draft methodology will force state regulators to utilize disputed, unsound science and will impose significant, and at times infeasible, treatment requirements upon regulated entities without a corresponding environmental benefit. This will deter the development of U.S. mineral resources, impose substantial costs on existing operations, and infringe upon state primacy under the CWA.

Selenium Water Quality Criterion and Implementation Guidance

I) Regulation

In July 2016, the U.S. Environmental Protection Agency (EPA) updated its chronic selenium freshwater criterion to include, for the first time, fish tissue-based limits that better reflect the fact that selenium toxicity in aquatic life is driven by consumption of selenium-contaminated food rather than direct exposure to selenium dissolved in water. However, while NMA supports the fish tissue-based approach, at the urging of the U.S. Fish and Wildlife Service and environmental organizations, EPA also included overly stringent water column-based limits and, while acknowledging that the fish tissue limits are more scientifically accurate, nevertheless required the water column limits to be applied in a number of permitting situations. Importantly, these default national water column concentrations are below natural background concentrations for certain parts of the country.

Additionally, because of the novelty of a fish tissue-based criterion, EPA also developed four draft guidance documents in Oct. 2016 designed to assist states in adopting and implementing the final 2016 criterion. Like the underlying criterion itself, these documents contain a number of flaws, including an undue emphasis on the water column limits and lack of flexibility for states.

II) Problems with the Regulation

While EPA's final 2016 selenium criterion appropriately utilized a fish-tissue approach, it also includes overly stringent limitations for both fish tissue and water column concentrations that were based on questionable and limited data sets and unduly conservative calculation methods. Furthermore, while recognizing the fact that fish tissue concentrations provide more scientifically accurate measurements of selenium impacts, both the criterion itself and, to an even greater extent, EPA's implementation guidance documents nevertheless require application of the overly stringent water column concentrations in numerous situations. These documents also limit state flexibility in terms of such important issues as National Pollutant Discharge Elimination System (NPDES) permitting, Total Maximum Daily Load (TMDL) calculations, and impaired waters listings.

Significant costs are associated with wastewater treatment for selenium. Notably, stringent limits can often only be met through the installation of reverse osmosis (RO) technology, if at all. While the costs of RO treatment vary, an example of two municipal wastewater treatment facilities in the Indianapolis area shows that the capital costs for installation of RO technology was $700 million, and annual costs for implementation were projected at $40 million – resulting in overall annualized treatment costs of $116.9 million, assuming that capital costs would be financed over 20 years. Furthermore, in

some instances treatment technologies might not be available to meet EPA's stringent limitations, particularly where background concentrations are naturally elevated, resulting in lost job opportunities, decreased economic growth, and a failure to develop the U.S.'s vast mineral potential with no corresponding environmental benefit.

III) E.O. 13771 and E.O. 13777 Criteria

EPA's selenium criterion and draft implementation guidance documents are candidates for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the criterion and implementation guidance (1) eliminate jobs and inhibit job creation; (2) impose costs that exceed their benefits; (3) place undue burden on the development and use of domestic energy resources; (4) offer opportunities for reduction in regulatory costs; and (5) intrude upon the rights of states. The final criterion and its implementation guidance documents utilize unsound science to impose enormous treatment costs upon regulated entities without a corresponding environmental benefit. This will deter the development of U.S. mineral resources and impose substantial costs on existing operations.

Clean Water Act Sec. 404 Guidance Documents

I) Regulations

Several administrative actions over time have fundamentally altered the careful balance between the U.S. Army Corps of Engineers (Corp), Environmental Protection Agency (EPA), and the states in Clean Water Act (CWA) Section 404 permitting. These actions have undermined the principle of cooperative federalism, ignored the Corps' experience in implementing the 404 program, and caused undue permitting delays and expenses that have had a negative impact on economic growth and job creation. Included in these actions are those guidance documents and memoranda related to:

i. CWA Section 401 water quality certifications: Regulatory Guidance Letter 90-04 – Water Quality Considerations, May 13, 1990; and Oct. 29, 2009 Memorandum from Steven L. Stockton, "Water Quality Certification"

ii. Jurisdictional determinations: 43 Opinion of the Attorney General 197, Sept. 5, 1979, "Civiletti Memorandum;" Jan. 19, 1989 "Memorandum of Agreement Between the Department of the Army and the Environmental Protection Agency Concerning the Determination of the Geographic Jurisdiction of the Section 404 Program and the Application of the Exemptions Under Section 404(f) of the Clean Water Act" and its Jan. 19, 1989 amendment; and Regulatory Guidance Letter 16-01 – "Jurisdictional Determinations," Oct. 2016

iii. Aquatic Resources of National Importance (ARNIs): "Clean Water Act Section 404(q) Memorandum of Agreement Between the Environmental Protection Agency and The Department of the Army," Aug. 11, 1992; Jan. 2002 Memorandum, "Designation of Aquatic Resources of National Importance Under Clean Water Act Section 404(q) Memorandum of Agreement with the Army Corps of Engineers;" Oct. 30, 2006 Memorandum for the Field, "U.S. Environmental Protection Agency (EPA) coordination between Regional offices and Headquarters on Clean Water Act (CWA) Section 404(q) actions;" and May 1, 2008 Memorandum, "Revised Coordination between EPA Regional Offices and Headquarters on Clean Water Act Section 404(q) Actions"

II) Problems with the Regulations

These administrative actions do not have a basis in the text of the CWA, have undermined the rights of states to protect their land and water resources, and have caused the 404 permitting process to become overly cumbersome and subject to undue bureaucratic delays. With respect to Sec. 401 water quality certifications, despite the fact that the CWA very clearly provides primacy states with the authority to develop and

determine compliance with state water quality standards, the aforementioned documents allow EPA to impermissibly override state decisions in the context of Sec. 404 permitting. Likewise, the listed actions related to jurisdictional determinations permit EPA to override Corps' jurisdictional determinations, even where neither the State nor the Corps believe federal jurisdiction exists. This authority is not found in the text or legislative history of the CWA, and ignores the Corps' primary role in issuing Sec. 404 permits. Additionally, under the guise of "minimizing duplication and delays," EPA created from whole cloth the "ARNI" designation, which permits EPA to "elevate" 404 permits on an ad hoc basis, delay their issuance, and demand additional extra-regulatory measures from permittees. All of these actions have led to permitting delays and red tape that has stifled economic growth and undermined the role of the states in the CWA.

III) E.O. 13771 and E.O. 13777 Criteria

The listed Sec. 404 administrative actions are candidates for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the documents (1) eliminate jobs and inhibit job creation; (2) impose costs that exceed its benefits; (3) place undue burden on the development and use of domestic energy resources; and (4) infringe upon state primacy under the CWA.

Clean Water Act Sec. 402 Guidance Documents

I) Regulations

The Obama Administration undertook several executive actions that set up barriers to cooperation between the U.S. Environmental Protection Agency (EPA) and the states in the implementation of Clean Water Act (CWA) Sec. 402 – the National Pollutant Discharge Elimination System (NPDES) permitting program. These actions have violated both the text of the CWA and the principles of cooperative federalism established therein, weakened environmental protection, and undermined the relationship between state and federal partners. They include: (1) *Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order* (July 21, 2011 memorandum); (2) Letter from EPA Administrator Lisa P. Jackson to Acting Assistant Secretary (Civil Works) Terrence Salt regarding the review of 110 pending permit applications in Appalachia (June 11, 2009); and (3) *Enhanced Surface Coal Mining Pending Permit Coordination Procedures* (July 11, 2009).

Additionally, EPA's policy documents on the scope of the permit shield provision found in CWA Sec. 402(k) are outdated and do not directly address situations where states include narrative (rather than numeric) limitations in NPDES permits. Those documents include the July 1, 1994 memorandum, *Policy Statement on the Scope of Discharge Authorization and Shield Associated with NPDES Permits*, as well as the memorandum from Robert Perciasepe, Steven A. Herman and Jeal C. Nelson, *Revised Policy Statement on Scope of Discharge Authorization Associated with NPDES Permits*. While the policies espoused in the documents remain sound, courts have inappropriately applied them, particularly in the context of narrative limits, to the detriment of permittees and the primacy of state CWA agencies.

II) Problems with the Regulations

The Obama Administration's guidance documents permit EPA to trample on the rights of states with primacy to administer the Sec. 402 program. Most notably, they espouse the position that EPA may effectuate a de facto change in a state water quality standard via its permit-specific objection authority under the guise of "interpreting" a state standard; attempt to substitute EPA's scientific judgment for the scientifically defensible judgment of the states; attempt to force states to determine when and how to conduct reasonable potential determinations; and inappropriately attempt to substitute a preferred approach to impaired waters listings and total maximum daily load development.

Furthermore, the permit shield documents should be updated to address recent situations, such as those involving the application of the permit shield to the application

of narrative water quality criteria. This lack of clarity has caused courts to limit the scope of the shield in a manner inconsistent with the text of the CWA, EPA's implementing regulations, and EPA's prior interpretations of the scope of the shield. By way of example, one court in West Virginia recently held that a coal company was liable for violating a non-existent "limit" in its permit because the permit generally alluded to narrative water quality standards, and the court – at the behest of environmental organizations – determined that the permit shield did not protect against the imposition of a post-hoc, judicially created numeric limit "interpreting" one such narrative standard that the state agency had expressly rejected during the permitting process. EPA should therefore update its permit shield policies to, among other things, provide for appropriate protections for dischargers in the context of narrative water quality criteria. In particular, EPA should clarify that dischargers can rely on a state's interpretation of what is required to meet both its numeric and narrative water quality standards – including a state's decision not to include any limit on a pollutant in an NPDES permit.

III) E.O. 13771 and E.O. 13777 Criteria

The Sec. 402 guidance and policy documents are candidates for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the documents (1) eliminate jobs and inhibit job creation; (2) impose costs that exceed its benefits; (3) place undue burden on the development and use of domestic energy resources; and (4) infringe upon state primacy under the CWA.

Interpretation of CWA Sec. 404(c) Authority

I) Regulations

On Jan. 13, 2011, the U.S. Environmental Protection Agency (EPA) withdrew the use of certain waters as disposal sites for discharges of fill material that had been authorized under a 2007 Clean Water Act (CWA) Sec. 404 permit for the Spruce coal mine located in West Virginia. The permit had been issued after nearly a decade of environmental reviews conducted by EPA, the Army Corps of Engineers (Corps), and the state, and EPA's withdrawal – which was done over the objection of the state - amounted to the first ever retroactive veto of a CWA Sec. 404 permit. EPA's action effectively eliminated 88% of the Spruce operation. While the D.C. Circuit eventually upheld EPA's action, in a strongly worded dissent Judge Kavanaugh objected to the fact that EPA did not consider the economic costs of its revocation, and found that "EPA's utterly one-sided analysis did not come close to satisfying the agency's duty under the Administrative Procedure Act to consider and justify the costs of revoking [the Spruce permit]."

Then, in July, 2014, EPA again took an unprecedented step with respect to CWA Sec. 404(c), and issued a proposed determination effectively vetoing any mining activities at the Pebble copper, gold, and molybdenum deposit. Importantly, that veto was done prior to the submittal of any 404(c) permit application, and was based on a highly questionable hypothetical mine scenario created by EPA scientists without adequate input from Alaska, the Corps, or, perhaps most notably, mining engineers. This process bypassed the proper state and federal CWA channels for evaluating any given project, and ignored the extensive (8-year, $120 million) environmental studies conducted by the proponents of the Pebble Mine. By stopping mine development, the Obama Administration halted the creation of thousands of near-term construction jobs and 1,000 full-time jobs throughout the mine's first 25 years, and stranded over $700 million in investment in addition to 80.6 billion lbs. of copper, 5.6 billion lbs. of molybdenum, and 107.4 million oz. of gold.

II) Problems with the Regulations

EPA's application of 404(c) during the Obama Administration thwarted the concepts of due process and fundamental fairness, and had significant negative impacts on economic investment and job growth. Investors are unlikely to risk their capital if they know a permit is only as permanent as the current election cycle, nor are they likely to explore opportunities in a regulatory atmosphere that allows the federal government to veto projects before project proponents have even applied for a permit. As underscored by the plethora of amicus briefs filed in the Spruce case, these concerns span the entire spectrum of sectors in the U.S. economy. By allowing the Pebble permitting process to move forward, and by reevaluating the Spruce decision in light of its devastating

economic impacts and failure to properly consider the views of the state CWA agency, the new Administration has the opportunity to reinvigorate investment in U.S. industries and stimulate economic growth and job creation.

Furthermore, EPA should consider updating the regulations related to the use of CWA Sec. 404(c) to ensure that any proposed future use of 404(c) has taken into account economic considerations and is based on sound science.

III) 13771 and E.O. 13777 Criteria

EPA's CWA Sec. 404(c) vetoes of the Spruce and Pebble mines, and 404(c) regulations, are strong candidates for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the regulatory actions (1) eliminate jobs and inhibit job creation; (2) impose costs that exceed their benefits; (3) place undue burden on the development and use of domestic energy resources; (4) offer opportunities for reduction in regulatory costs; and (5) intrude upon the rights of states.

NPDES Updates Rule

I) Regulation

The National Pollutant Discharge Elimination System (NPDES) Applications and Program Updates Rule (NPDES Rule), proposed in May 2016, includes proposed changes to NPDES permit application requirements, the U.S. Environmental Protection Agency's (EPA) ability to object to administratively continued NPDES permits, the general water quality-based permitting process, state documentation of permitting decisions and the Clean Water Act (CWA) Sec. 401 state certification process.

II) Problems with the Regulation

While the proposed rule contains numerous problematic provisions, the most grievous from the perspective of NPDES permit holders is the provision allowing EPA to designate certain administratively continued permits as "proposed permits" if EPA determines that states are not acting quickly enough on renewal applications. Pursuant to that provision, EPA could designate administratively continued "environmentally significant" permits (which would include, among many others, all mining-related NPDES permits which have been administratively continued for either two or five years) as "proposed," thereby effectively taking over the permitting authority of the state on an ad-hoc, permit-by-permit basis. Notably, often times states have not acted on renewals because they are looking at complex scientific, legal, or technical issues associated with the permit, and the proposal provides no evidence that EPA is in a better position to more quickly or efficiently resolve such issues.

The proposal also includes incorrect language with respect to anti-backsliding, as well as multiple other provisions that infringe upon the CWA authority of the states, such as requirements concerning data analysis and dilution.

III) E.O. 13771 and E.O. 13777 Criteria

EPA's final report, *Protecting Aquatic Life from Effects of Hydrologic Alteration*, is a candidate for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the report (1) is unnecessary; (2) intrudes upon the rights of states; and (3) inhibits job creation.

Compensatory Mitigation for Losses of Aquatic Resources

I) Regulation

On Apr. 10, 2008, EPA and the U.S. Army Corps of Engineers jointly promulgated a rule establishing requirements for compensatory mitigation associated with Clean Water Act (CWA) Sec. 404 permits. Those requirements can be found at 40 CFR Part 230 and 33 CFR Parts 325 and 332.

II) Problems with the Regulation

The compensatory mitigation requirements contained in the 2008 rule have been subject to multiple interpretations and inconsistently applied at mining operations. This has resulted in constantly changing requirements and unjustified mitigation rations. The rule has also led to the imposition of requirements that are not practical or appropriate when applied in the context of mining operations, such as certain financial assurance, long-term management, conservation easement and advance mitigation requirements. The inconsistent and inappropriate application of the rule's requirements have imposed considerable costs on the mining industry.

III) E.O. 13777 Criteria

The 2008 compensatory mitigation rule is a candidate for revision under Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda) as it inhibits job growth and contains costs that exceed its benefits. Significant revisions to the rule are required to provided much-needed regulatory certainty with respect to mitigation requirements in the context of the 404 program.

Hydrologic Alteration Report

I) Regulation

In late Dec., 2016, the U.S. Environmental Protection Agency (EPA) and U.S. Geological Survey (USGS) finalized a technical report, *Protecting Aquatic Life from Effects of Hydrologic Alteration*. The report outlines the impacts hydrologic alteration, particularly stream flow modification, can have on aquatic life, and provides a framework states can use to develop numeric flow regime targets necessary to support the biological integrity of streams and protect aquatic ecosystems. While the document is purportedly non-prescriptive in nature, it remains to be seen whether states will have to consider the report in triennial reviews of their water quality standards packages, or how environmental organization may utilize the document in the context of Clean Water Act (CWA) citizen lawsuits. In particular, states that utilize narrative (non-numeric) flow criteria, and permittees that have narrative flow criteria limits, could be especially susceptible to outside lawsuits.

II) Problems with the Regulation

The final report is premised upon the incorrect assumption that any modification in natural stream flow results in a degradation of downstream aquatic life, and as such fails to acknowledge the potential benefits of flow alteration and the fact that numeric flow targets can conflict with CWA programs, state water rights, the Surface Mining Control and Reclamation Act (SMCRA), and other applicable federal and state laws. EPA and USGS also failed to consult with relevant state and federal agencies before finalizing the report, and as such the report fails to provide states that have adopted narrative flow criteria with information critical to implementing that criteria in a manner that best protects water quality goals.

Additionally, while the final report removed an inaccurate legal analysis contained in the draft version, it fails to acknowledge that the only federal case to look at the issue has held that, because flow is not a “pollutant,” it is not within EPA’s authority to regulate under the CWA. That failure could lead to outside organizations and courts misapplying the document, particularly in the context of CWA National Pollutant Discharge Elimination System (NPDES) permitting situations. This is particularly critical since mining – as well as many other activities such as water management, groundwater pumping, urban development, thermoelectric power generation, and agriculture – often require some form of hydrologic alteration.

III) E.O. 13771 and E.O. 13777 Criteria

EPA’s final report, *Protecting Aquatic Life from Effects of Hydrologic Alteration*, is a candidate for revision under Executive Order 13771 of January 30, 2017 (Reducing

Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda). Specifically, the report (1) eliminates jobs and inhibits job creation; (2) imposes costs that exceed its benefits; (3) places undue burden on the development and use of domestic energy resources; (4) is unnecessary; and (5) intrudes upon the rights of states.

Water Quality Standards Regulatory Revisions

I) Regulation

On Aug. 21, 2015, EPA finalized changes to the federal regulations governing the Clean Water Act (CWA) water quality standards (WQS) program found at 40 CFR Part 131. Under the CWA, approved states and tribes are the primary administrators of the WQS program while EPA retains certain oversight authority. The rule updated several aspects of the WQS program in a manner that limited and infringed upon state authority, including the regulations governing designated uses, triennial reviews, antidegradation, and the use of variances and compliance schedules in National Pollutant Discharge Elimination System (NPDES) permitting.

I) Problems with the Regulation

The 2015 water quality standards revisions have infringed upon the primary role of the states in setting CWA WQS, and unnecessarily restrict the use of available CWA mechanisms necessary for the establishment of appropriate WQS and NPDES permit limits. Specifically, the rule: (1) inappropriately codified a "rebuttable presumption" that the uses specified in CWA Sec. 101(a)(2) – fishable/swimmable – are attainable unless a costly use attainability analysis is performed which justifies removing the use, leading to overly stringent and costly permitting requirements; (2) requires states to review any new or revised Sec. 304(a) criteria and explain any decision not to adopt such criteria; (3) established inappropriate stringent new requirements for identifying high quality waters, analyses of alternatives and antidegradation implementation methods; and (4) placed new burdens on the use by states of variances and compliance schedules in NPDES permitting.

EPA also assumed that the proposal would not have an economic impact on the regulated public. However, in doing so, EPA ignored the fact that the regulated community would be substantially impacted by the requirements contained in the rule, and must either directly undertake or pay for the procedures outlined in the rule to be completed when states are unable to fund them.

I) E.O. 13771 and 13777 Criteria

The 2015 water quality standards rule is a candidate for revision under Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs), and Executive Order 13777 of February 24, 2017 (Enforcing the Regulatory Reform Agenda), as it (1) inhibits job growth, (2) is unnecessary, (3) contains costs that exceed its benefits, (4) places undue burden on the development and use of domestic energy resources, (5) offers opportunities for reduction in regulatory costs, and (6) intrudes upon the rights of states.

Drinking Water Standards for Beryllium

I) Regulation

EPA's six-year review of drinking water standards identified beryllium (and 9 other chemicals) as a candidate for an increase in its maximum contaminant level goal formerly established by EPA based on a new health assessment. 82 Fed. Reg. 3518, 3527 (Jan. 11, 2017). However, in its announcement EPA proposes not to pursue this revision of the beryllium drinking water standards because of its belief that there is not any meaningful opportunity for costs savings from an upward revision. 82 Fed. Reg. 3525.

II) Problems with the Regulation

EPA's position is incorrect. EPA failed to consider several ways in which public and private sector costs would be saved if EPA were to increase the drinking water standards for beryllium. There is no benefit to an overly protective beryllium drinking water standard, but it does impose significant cost penalties. The beryllium drinking water standard is used by numerous federal and state agencies in establishing surface water, groundwater and soil cleanup levels in a variety of programs. For example, EPA requires that remedial actions for contaminated groundwater at Superfund sites attain the agency's drinking water standards. OSWER Directive 9281.1-33 requires that aquifers be restored to drinking water standards wherever possible. EPA's Superfund Management System reports that beryllium was identified as a surface water or ground water as a constituent of concern requiring remediation at 212 National Priority List (NPL) sites. Similarly, EPA reports that beryllium was a contaminant of concern in soils, sediments or sludge at 222 NPL sites. The drinking water standard for beryllium is used to derive the cleanup levels for these media as well.

The beryllium drinking water standard is similarly used in other federal and state remediation programs. For example, remediation by the US Army Corps of Engineers under the Formerly Utilized Sites Remedial Action Program utilizes this standard in soil and water remediation. Developers of brownfield properties under the Ohio Voluntary Action Program are required to remediate groundwater to this standard. In all these programs, requiring cleanup to a standard that is lower than what is necessary to protect public health increases remediation and redevelopment costs and slows the return of properties to productive use and the jobs that result therefrom.

III) E.O. 13777 Criteria

The drinking water standards for beryllium are a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, and ineffective; (2) imposes costs that exceed benefits; and (3) is not based on sound science. As EPA recognizes, the beryllium

drinking water standard is outdated in light of new health assessment information; and to the degree that the current standard is overly stringent, it is ineffective in improving health results and imposes nationwide, adverse effects on remediation and redevelopment costs and jobs.

WASTE

Toxics Release Inventory (TRI) Reporting

I) Regulation

The Toxics Release Inventory (TRI) established under Section 313 of the Emergency Planning Community Right-to-Know Act (EPCRA) requires industrial facilities to report annually the "release" of certain toxic chemicals that meet threshold quantities for specified activities (*e.g.*, manufacture, process, or otherwise use) to the environment (*e.g.*, placed in some type of land disposal or emitted to the air or water). 42 U.S.C. § 11203. The purpose of the TRI is to: (1) inform the public about releases of toxic chemicals to the environment; (2) assist governmental agencies, researchers, and other persons in the conduct of research and data gathering; and (3) to aid in the development of appropriate regulations, guidelines, and standards. 42 U.S.C. § 11023(h). In 1997, EPA added the metal mining sector to the list of industries subject to TRI reporting. 62 Fed. Reg. 23,892 (May 1, 1997); 40 C.F.R. 372.22. The mining industry has been reporting under TRI since 1999 – 16 total years. EPA publishes annual reports on its website. The public can also access company reports.

II) Problems with the Regulation

The TRI was originally established for the manufacturing sector, in response to a series of chemical plant accidents, to support and promote emergency planning and provide information to the public on releases in their community. Today, EPA touts the TRI program as being a part of a "new approach to environmental protection" wherein information disclosure programs can be used to "create a strong incentive for companies to improve environmental performance." EPA emphasizes this aspect of the TRI program by highlighting a sector's pollution prevention (also known as P2) efforts in its annual reports.

Importantly, however, the application of the statutory terminology through regulation to mining has resulted in the requirement to report as "releases" on TRI reports the trace amounts of naturally occurring metal and metal compounds that are present in the rock and dirt that is moved and managed at a mine site. In fact, the vast majority of what the metal mining industry reports – from 85 to 99 percent – consists of the management of these naturally occurring substances in on-site land-based units. These units are engineered facilities permitted and regulated by exacting state and federal laws.

The sheer size of the mining industry's reported "release" numbers dwarfs TRI reporting by any other industry. Most recently, the metal mining sector remains the largest reporting sector at 37 percent, which is more than twice the chemical sector at 15 percent. As EPA acknowledged in the 2015 TRI National Analysis, "toxic chemical quantities reported by [the metal mining] sector are not especially amenable to source reduction, because they primarily reflect the natural composition of the ore and waste rock."

TRI release estimates reported under the TRI program are consistently misused by the public and EPA's program offices to irresponsibly paint an alarmist and inaccurate picture of the metal mining industry's potential for posing health and environmental risk. Most recently, EPA's Office of Land and Emergency Management relied in part on TRI data to target the metal mining industry as a "high risk" sector that warranted new financial assurance requirements under the Comprehensive Environmental Response, Compensation, and Liability Act. *See* 82 Fed. Reg. 3477 (Jan. 11, 2017). The TRI program, however, is strictly a volume-based reporting requirement, not an assessment of risk to public health or the environment.

III) E.O. 13777 Criteria

The TRI program is a candidate for revision under E.O. 13777 as it: (1) is outdated, unnecessary, and ineffective; and, (2) imposes costs that exceed benefits. Over 15 years ago, two successful cases brought by the mining industry produced court rulings that should have substantially reduced the scope of these reporting requirements. *NMA v. Browner*, 2001 U.S. Dist. LEXIS 915 (D. Colo. Jan. 16, 2001); *Barrick Goldstrike Mines v. Whitman*, 260 F. Supp. 2d 28 (D.D.C. Apr. 2, 2003). EPA has resisted full implementation of those rulings in a manner that would imbue the reporting requirements with more rational and less misleading information about the performance of the mining sector. This paperwork exercise burdens the mining industry with millions of dollars of compliance costs annually.

URANIUM

Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings and Uranium in Situ Leaching Processing Facilities

I) Regulation

The U.S. Environmental Protection Agency (EPA) has proposed revisions to "40 CFR 192, Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings and Uranium In Situ Leaching Processing Facilities." The proposal would create new groundwater data collection, monitoring and restoration standards for facilities that recovery uranium via *in situ* recovery (ISR) processes. The rulemaking is premised on the allegation that ISR activities may impact adjacent aquifers that either are now or could someday be sources of drinking water. Under the Atomic Energy Act (AEA) as amended by the Uranium Mill Tailings Radiation Control Act (UMTRCA), EPA does have a role in setting generally applicable environmental standards uranium recovery facilities. The U.S. Nuclear Regulatory Commission, however, is charged with implementation and enforcement of such standards. The proposed rule goes well beyond setting standards, a concern raised by the NRC's General Counsel.

II) Problems with the Regulation

The primary flaw with the rule is EPA's failure to properly assess the risks of ISR operations to groundwater. The agency provides no evidence in the rulemaking record that ISR facilities have ever adversely impacted an adjacent aquifer. Tellingly, EPA admits that the agency finds "it difficult to characterize the probability or magnitude of future contamination problems, or the costs inclined in remediating such future contamination." EPA's unrealistic assumptions about modeling groundwater contamination scenarios and associated cancer risk exposure pathways skewed its risk analysis to justify the rule's long-term groundwater monitoring provisions. Specifically, EPA modeled failure scenarios (catastrophic spills) that are not representative of groundwater incursion scenarios that long term monitoring requirements are designed to prevent and used a model that ignored existence of best management practices routinely used to ensure detection and remediation of leaks before they reach nearby receptors.

In addition, EPA minimizes the importance of studies that show adjacent aquifers have been adequately protected by existing federal and state programs, even their own. As an example, EPA's underground injection control (UIC) program under the Safe Drinking Water Act (SDWA) is designed to prevent endangerment of underground sources of drinking water (USDWs). EPA maintains that reliance on the requirements of the UIC program alone would not adequately address groundwater protection at ISR facilities, given there are not groundwater restoration requirements under the UIC program. EPA is correct that such restoration requirements do not exist but fails to note the lack of such requirements is due to the fact that ISR operations can only occur in exempted aquifers. In order for an ISR operation to proceed, a UIC permit is required and typically, an aquifer exemption is needed. In the case of ISR operations, the aquifer

exemption is granted either due to the mineralization or the poor natural quality of the water or both. The aquifer exemption effectively removes the aquifer from the protection of the SDWA due to the finding that it does not now currently serve as a source of drinking water and it cannot now and will not in the future serve as a source of drinking water. Additionally, EPA ignores the fact that both NRC and state regulatory authorities do require restoration of ISR operations under existing programs. A major flaw in EPA's proposed rule is the failure to adequately acknowledge the impact of existing federal and state programs in protecting adjacent aquifers from any potential risks of ISR operations.

EPA's cost benefit analysis for the rulemaking is also fatally flawed, particularly the calculations relating to social benefits. The analysis is Inconsistent with OMB Circular A-4 because it quantifies social benefits using avoided costs of remediating a hypothetical groundwater plume. EPA's own economic guidelines only allow use of replacement costs when: (1) damage to the asset is the only cost of the environmental deterioration; and (2) the least expensive way to achieve the level of satisfaction realized before the deterioration would be to replace the asset. Further, EPA's analysis ignores many of the costs related to the rule's long-term stability monitoring requirements including costs related to bonding; land rental/mineral rights; labor; utilities; regulatory compliance; transfer payments such as royalties to the Bureau of Land Management, NRC fees and taxes. With all costs and revenue impacts considered, several impacted companies determined that compliance costs per pound of uranium recovered would exceed the current per pound sales price.

III) E.O. 13777 Criteria

This rulemaking is a candidate for revision under E.O. 13777 as it: (1) eliminates jobs and inhibits job creation; (2) is unnecessary as EPA has not identified a risk to human health or the environment; (3) imposes costs that exceed benefits; and (4) creates a serious inconsistency with other federal and state programs.

National Emissions Standards for Radon Emissions from Operating Mill Tailings

I) Regulation

The U.S. Environmental Protection Agency (EPA) finalized its rulemaking, "40 CFR Part 61, Subpart W: Revision of National Emission Standard for Radon Emissions from Operating Mill Tailings" on Jan. 17, 2017. This rulemaking marks an expansion of EPA Clean Air Act (CAA) National Emissions Standards for Hazardous Air Pollutants (NESHAP) authority to include fluid retention impoundments such as evaporation ponds, storage ponds, and other similar ponds at uranium recovery facilities (non-conventional impoundments).

II) Problems with the Regulation

The rulemaking is an unnecessary and unlawful expansion of EPA's Subpart W CAA authority in a manner that undermines the jurisdictional limits placed on EPA in the Atomic Energy Act (as amended by the Uranium Mill Tailings Radiation Control Act). The rule contradicts 20 years of consistent interpretation that Subpart W is only applicable to uranium mill tailings impoundments. EPA's position is inconsistent with the language and the rulemaking history associated with Subpart W since Subpart W specifically references "uranium mills and their associated tailings." In addition, the preamble to the preexisting rule specifically states that the radon cover requirements in Subpart W's work practice standards are not intended to apply to such fluid retention impoundments.

EPA's decision to regulate these non-conventional impoundments means that uranium recovery licensees are now required to obtain an EPA construction permit for each impoundment and evaporation pond *as well as* a U.S. Nuclear Regulatory Commission (NRC) license for the same facilities. This duplicative regulation imposes new costs that are entirely unnecessary as EPA specifically acknowledged in the proposed rule's preamble that the scientific data shows that such impoundments pose little risk to human health and the environment. Recent science confirms EPA's earlier conclusions that risks are minimal. Despite any evidence of risk, non-conventional impoundments will be subject to the burdensome and onerous requirements including the requirements for daily inspections and weekly collection of photographic evidence to verify water levels in such impoundments.

III) E.O. 13777 Criteria

This rulemaking is a candidate for revision under E.O. 13777 as it: (1) is unnecessary as EPA has not identified a risk to human health or the environment; and (2) creates a serious inconsistency with other federal and state programs.

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III) E.O. 13777 Criteria

This rulemaking is a candidate for revision under E.O. 13777 as it: (1) is unnecessary as EPA has not identified a risk to human health or the environment; and (2) creates a serious inconsistency with other federal and state programs.

To: Jackson, Ryan[jackson.ryan@epa.gov]; Dravis, Samantha[dravis.samantha@epa.gov]; Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]
From: Hilary Moffett
Sent: Mon 5/15/2017 9:52:45 PM
Subject: API Comments on Task Force
API EPA reg reform final comments 5-15-17.pdf
API Attachment 1 - Comments on specific regulations 5-15-17.pdf

Good afternoon,

Attached, please find a copy of API's comments that were submitted just moments ago. We will reference these comments in out meeting tomorrow.

Thanks,

Hilary

To: Dravis, Samantha[dravis.samantha@epa.gov]
From: Khary Cauthen
Sent: Thur 5/25/2017 11:48:25 PM
Subject: FYI: API letter requesting withdrawal and revisitation of the Oil & Gas CTGs
API Comments on Draft CTGs 12042015.pdf
2017-05-25 Letter to EPA re CTGs Final.pdf

From: Howard Feldman
Sent: Thursday, May 25, 2017 5:06 PM
To: Dunham, Sarah (Dunham.Sarah@epa.gov)
Subject: API letter requesting withdrawal and revisitation of the Oil & Gas CTGs

Sarah,

Please see the attached letter from API requesting that EPA withdraw and revisit the *Control Techniques Guidelines for the Oil and Natural Gas Industry* (CTGs), released on October 27, 2016. Please let me know if you have any questions.

Be well,

Howard

Howard J. Feldman

Senior Director

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December 4, 2015

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2015-0216
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane

emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, carbon dioxide (CO_2) emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (NSPS Subpart OOOOa, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

Howard J. Feldman

Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

Attachment

API Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry

December 4, 2015

Docket ID No. EPA-HQ-OAR-2015-0216

Executive Summary

As detailed in our comments, API has numerous concerns with EPA's draft Control Techniques Guideline (CTG) for the Oil and natural gas (O&G) sector. EPA has indicated the desire to finalize the draft CTG in early 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments. This is an unrealistic schedule for issuing a complex guidelines with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final guidance to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of EPA's draft Reasonably Available Control Technology (RACT) recommendations and the associated model regulatory text. The one-size-fits-all approach is not appropriate for an industry that varies greatly in the type, size and complexity of operations. EPA has supported its RACT recommendations using economic studies based on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

EPA Must Develop Applicability Thresholds Based On VOC Content To Avoid Requiring Controls That Are Clearly Not Cost Effective And Not RACT For Areas With Low-VOC Gas

Issue – By performing all RACT analyses using a single representative gas composition, EPA has recommended RACT for several fugitive sources that will result in cost effectiveness values considerably higher than EPA considers acceptable in many areas of the U.S. The volatile organic compound (VOC) content of the gas at a site is directly related to the VOC emissions, and thus, the VOC emission reduction when controls are applied. By using a single gas composition for all RACT analyses, EPA did not properly evaluate the VOC cost effectiveness for dry gas, coal bed methane, and other areas that have low-VOC gas. API has performed an analysis that provides recommendations for these thresholds that are technically sound.

Recommendation – Include VOC content applicability thresholds that ensure that areas with low VOC gas are not subject to controls that are not cost effective.

Refer to Section 2.0 for detailed comments on this matter.

Storage Vessel Monitoring Requirements

Issue – The CTG model rule includes onerous continuous parameter monitoring requirements for storage vessels that are considerably more stringent than EPA has proposed for NSPS. The RACT monitoring requirements for storage vessels should not be more stringent than the Best System of

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Emission Reduction (BSER) monitoring requirements in the NSPS. Further, EPA did not include the costs of this more stringent monitoring in the impacts assessment for storage vessels.

Recommendation – Make the continuous compliance requirements in the CTG consistent with the proposed requirements in NSPS subpart OOOOa.

Refer to Section 13.8 for detailed comments on this matter.

Fugitives At Well Sites And Compressor Stations

Issue – The draft CTG has a process that requires significant, unnecessary recordkeeping and reporting, and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation – Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Section 17.0 for detailed comments on this matter.

EPA Should Delay Finalizing the CTGs Until Six Months After NSPS OOOOa is Finalized

Issue – The CTGs and NSPS OOOO/OOOOa regulate the same type of equipment. Proposing these two actions at the same time resulted with significant inconsistences that appear to be unintentional and would be illogical if the inconsistences were intended. Finalizing these two actions at the same time is like to result in inconsistences in the final actions, as well as duplication of technical errors.

Recommendation – The CTG actions can be delayed without significant impacts. EPA should delay finalizing the CTGs until six months after NSPS OOOOa is finalized.

Refer to Section 1.0 for detailed comments on this matter.

The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 Tpy VOC

Issue – The proposed rule applies the same 6 TPY VOC applicability for new storage vessels to existing storage vessels. Cost of control is higher for existing storage vessels than new storage vessels. EPA's cost estimate underestimates the retrofit costs for an existing storage vessel by ignoring other costs such as purchasing additional land to meet safety buffers for combustion devices. Some existing storage vessels would need to be replaced since they could not handle the additional pressure required for a closed vent system to a control device. These additional considerations make a 6 TPY VOC applicability threshold economically unreasonable for existing tanks.

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Solution – Increase the applicability threshold to 10 – 15 TPY VOC to assure that controls are economically feasible.

Refer to Section 13.2 for detailed comments on this matter.

EPA Should Exempt Natural Gas Pneumatic Pumps That Emit At A Rate Lower Than A High Bleed Controller

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit.

Recommendation – EPA should exempt low emitting pumps, i.e. pumps that emit at a rate lower than a high bleed controller. This should include low usage equipment as well. This is consistent with the position taken in subpart OOOO and reinforced under the subpart OOOOa proposal for pneumatic controllers.

Refer to Section 15.4.1 for detailed comments on this matter.

Pneumatic Pump Control Technical Feasibility

Issue – EPA has ignored major technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should provide an exemption from the requirements to control pump emissions where it has been determined to not be technically feasible.

Refer to Sections 15.0 for detailed comments on this matter.

Common Sense Voluntary Reductions And Incentives Will Lead To Increased Early Emission Reductions

Issue – The CTGs should work in concert with the Methane Challenge Voluntary Initiative to seek common sense voluntary reductions and incentives, which will lead to increased early emission reductions. If the Administration wishes to seek additional reductions through a federal framework, the best approach would be a voluntary program without duplicative mandatory regulation. The industry is interested in participating in a well-constructed voluntary program, and has shared options for achieving substantial methane emissions reductions more rapidly than regulations would allow. Industry and EPA's incentives are aligned in desiring to keep methane in the pipeline, to reduce losses and improve product recovery. Industry members strive to evaluate options for cost effective measures to reduce emissions and implement them where they can achieve the greatest reductions. For example, EPA recently reported that total methane emissions from natural gas systems are down 11 percent since 2005 despite significant growth in production. To continue this progress and maximize the results, the industry requires flexible voluntary programs with appropriate incentives, not inflexible regulatory mandates.

Solution – Eliminate duplicative regulation of emissions.

Refer to all sections for detailed comments on this matter.

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Attachments

Attachment A - Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

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GENERAL COMMENTS

1.0 GENERAL PROCEDURAL AND LEGAL COMMENTS

EPA has requirements in the proposed Control Technique Guidelines (CTG) on the same sources regulated in NSPS, Subpart OOOO, including currently proposed amendments, and the proposed NSPS Subpart OOOOa. Writing two separate rules on the same equipment at the same time inevitably cause inconsistences between the rules, as has been the case in these proposed rules. For instance, continuous parameter monitoring systems (CPMS) are required in the proposed CTGs for control devices, regardless of what type of affected source the emissions are coming from. However, NSPS Subpart OOOOa requires CPMS for emissions coming from centrifugal compressors or pneumatic pumps, but only sensory monitoring and inspection requirements for storage vessels. Discussions with EPA indicate they intended to propose the same compliance assurance in both NSPS Subpart OOOOa and the CTGs.

An existing storage vessel regulated by the CTG may be located right next to a new storage vessel regulated by NSPS, Subpart OOOOa. Requiring stringent CPMS monitoring for the existing storage vessel and visual inspections for the new storage vessel will be very confusing to both the agency inspectors and to the oil & gas industry personnel in trying to comply with the two different sets of requirements. Retrofitting existing equipment is more expensive than the respective increased cost for new equipment, thus you would expected existing equipment to have less stringent requirements than those for new equipment. The opposite occurred in the proposal. EPA widely utilized Best System of Emissions Reduction (BSER) as Reasonably Available Control Technology (RACT), which is not always supportable. However, in all cases BSER should be considered a cap to RACT (see Section 4.1).

For this reason, API requests that EPA delay finalizing the CTGs for at least six months after the NSPS, Subpart OOOOa rule has been finalized. Finalizing the NSPS first allows the requirements to be implemented during the initial equipment construction when it is most effective. Additionally, the existing CTGs are expected to have the most impact on existing equipment in new nonattainment areas designated due to the lowering of the Ozone NAAQS in October 2015. These new nonattainment areas are not expected to be finalized until October 2017. Further, the CTGs require state regulatory actions before these requirements can be implemented. Thus, delaying the finalized CTG until early in 2017 will cause no delays in implementation for these areas . The CTGs are not expected to have significant impact in existing ozone nonattainment areas, since RACT requirements are already in place (i.e in Denver, CO; Houston, Dallas, and Beaumont, TX; etc .). Where states feel that regulatory changes are needed promptly, they can proceed with those actions based on the NSPS OOOO/OOOOa final rule.

2.0 EPA MUST DEVELOP APPLICABILITY THRESHOLDS BASED ON VOC CONTENT TO AVOID REQUIRING CONTROLS THAT ARE CLEARLY NOT COST EFFECTIVE AND NOT RACT FOR AREAS WITH LOW-VOC GAS

CTGs are required by the CAA to help an area obtain the NAAQS. As such, CTGs cannot consider the benefits of methane reductions in the economic analysis of control options. As proposed, the CTG would require controls in production fields (i.e. coalbed methane or dry gas fields) where little to no VOC reductions would occur. EPA should adopt minimum VOC thresholds for fugitive monitoring, pneumatic pumps, pneumatic controllers and centrifugal

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compressors, below which no controls would be required to maintain the cost effectiveness of controls where little or no benefits to NAAQS attainment would occur.

2.1 Cost Effectiveness Is Key Element Of RACT

As stated in Chapter 1 of the draft CTG, EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 FR 53761 (September 17, 1979). Historically, the primary measure that EPA has relied upon to assess economic feasibility is the cost of the emission reduction in relation to the level of emission reduction. This "cost-effectiveness" is calculated by dividing the annual costs of the control (including capital recovery along with operating and maintenance costs) by the annual emission reduction.

EPA calculated and showed the cost effectiveness for every option considered. The cost effectiveness values for the fugitive emission sources that EPA recommended as RACT are summarized in Table 2-1.

Table 2-1 EPA VOC Cost Effectiveness Values from CTG

Source	Cost Effectiveness ($/ton VOC reduced)	
	without savings	with savings
Reciprocating Compressor (Gathering and Boosting Station)	$1,132	$298
Reciprocating Compressor (Processing Plant)	$334	($500)
Pneumatic Controller (Well Site)	$210	($627)
Pneumatic Controller (Processing Plant)	$2,807	$1,970
Pneumatic Pump (Diaphragm) – Existing Control Device	$312	$312
Pneumatic Pump (Piston) – Existing Control Device	$2,840	$2,840
Equipment Leaks (Processing Plant)	$2,844	$2,010
Fugitive Emissions (Natural Gas Well Site)	$2,945	$2,111
Fugitive Emissions (Oil Well Site)	$12,294	$11,460
Fugitive Emissions (Gathering and Boosting Station)	$2,710	$1,876

It is evident that EPA relied on the cost effectiveness in determining the economic feasibility of controls for the oil and natural gas industry, as every section of the document that discusses the recommended RACT level of control includes a discussion of cost effectiveness. For example, on pages 7-17 and 7-18 of the CTG, EPA states:

> *"Our rationale for selecting 95 percent control when there is an existing control device is that, as presented in Table 7-4 in section 7.3.1.4 of this chapter, the VOC cost of control when an existing combustion device is available on-site was estimated to be $312/ton for diaphragm pumps and $2,850/ton for piston pumps. As presented in Table 7-6 in section 7.3.1.5 of this chapter, the VOC cost of control when an existing VRU is available on-site was estimated to be a cost savings for diaphragm pumps and $2,007/ton for piston pumps. We consider these costs to be reasonable. Requiring control where there is not an existing control device on-site was not considered to be reasonable available technology, and the costs per ton of VOC reduced are estimated at greater than $20,000 per ton of VOC reduced for diaphragm pumps and over $200,000 per ton of VOC reduced for piston pumps."*

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This citation also shows that there are levels at which EPA considers the cost effectiveness for VOC to be reasonable, as well as levels that EPA considers to be unreasonable. Historically, EPA has avoided establishing a bright line that separates reasonable versus unreasonable, but past EPA decisions do provide insight into what constitutes reasonable.

The best and most relevant example of EPA's view of a reasonable cost effectiveness level for VOC for the oil and natural gas industry was provided in EPA's final decision related to the 4 tpy alternative emission limitation for storage vessel affected facilities under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429.

> *". . . . our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately $5,100 per ton. This cost increases to approximately $6,900 per ton at an emission rate of 3 tpy, and to approximately $10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of $5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy."*
>
> *"In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy."*

There are several key facts worthy of note regarding these statements related to establishing a reasonable cost effectiveness level for RACT for fugitive sources from this industry.

1) This decision was specific to the exact industry that is covered by the oil and natural gas CTG.
2) The 2007 rulemaking cited as precedent was for fugitive sources analogous to most of the sources covered in the CTG. Specifically, this rulemaking was for "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; Final Rule."
3) This threshold was used by EPA to establish a cost effectiveness level considered unreasonable for BSER, which is by definition, more stringent that RACT. Therefore, based on clear precedent summarized above, EPA must consider any cost effectiveness value greater than $5,700 per ton of VOC reduction to be unreasonable for the purpose of recommending RACT for fugitive source the oil and natural gas industry.

2.2 Cost Effectiveness Of Recommended Fugitive RACT For Oil Wells Is Unreasonable

Given this fact, an obvious first observation is that the cost effectiveness for EPA's recommended RACT for fugitive emissions at oil wells is well above this reasonableness threshold. EPA provided a vague and unsupportable rationale for ignoring the results of their own analysis and recommending level of control estimated to have a cost effectiveness of $11,460 (considering savings), which is more than double the level previously determined to be unreasonable (see

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pages 9-32 and 9-33 of the CTG). Without any consideration of any other factors discussed below, EPA must not finalize a recommendation of any fugitive leak monitoring program as RACT for fugitive emissions at well site. This is discussed in more detail in section 17.0.

2.3 Variation In VOC Content Of Gas Directly Impacts Emission Reductions And Cost Effectiveness

A lower VOC content would reduce the emission reduction achieved by a technology, thus increasing the cost effectiveness. For instance, consider a fugitive emission source where the cost of reducing the emissions is $10,000 per year. If the VOC emissions reduction for this measure at a site with a gas stream consisting of 20% VOC by weight is 5 tons per year, the cost effectiveness would be $2,000 per ton. However, applying the same reduction measure to a site where the gas content of the stream is 5% VOC by weight, the VOC emission reduction would be reduced to 1.25 tons per year and the cost effectiveness would increase to $8,000. Therefore, this difference in VOC content causes the cost effectiveness to be reasonable (by EPA's previous determination) at one site and unreasonable at another.

All the analyses in the CTG were conducted using a single representative gas composition.[1] For oil and natural gas production, this gas composition included 6.8% VOC by volume and 18.3% VOC by weight.

API notes that the documentation for the selection of this representative composition is lacking. In Table 1 of the 2011 EC/R memorandum, gas composition information from a variety of sources was presented. After a review of the available data, the outcome was that only data provided by the Gas Research Institute (GRI) data during the 1995 MACT development was used to calculate the representative gas compositions. Part of the rationale for relying on this GRI data was that a comparison of the GRI data to the other information showed that the GRI data was representative. However, Table 1 and the paragraph that describes this conclusion are severely flawed. For example, the memo states "For production, the 1995 GRI data is well within the ranges of the other data sources, which range from 1.19 to 11.6 percent for VOC by volume." However, the maximum VOC content shown in Table 1 for the other data sources is 5.7 volume percent. Also, Table 1 presents the average VOC content of the other data sources as 3.5 volume percent, as compared to an average of 3.66 volume percent for the GRI data. However, in Table 5 of the EC/R memorandum (which summarizes the GRI data) the sum of the volume percentages of the VOC components is 6.8 percent. Not only does this not match the 3.66 percent provided as the average in Table 1, it is also higher than the maximum VOC content of all the other data sources evaluated. This raises questions about the overall credibility of the analysis leading to EPA's representative composition. It also indicates that EPA may have significantly overestimated VOC emissions when this representative composition was used. In order for the public to have confidence in EPA's overall impacts assessment, EPA must explain these discrepancies in the documentation of the representative analysis and make corrections as necessary.

Despite the significant errors discussed above in EPA's documentation, API believes that the resulting representative gas composition (containing 6.8 percent VOC by volume and

[1] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

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18.3 percent VOC by weight) is a reasonable portrayal of an "average" gas composition across the U.S. However, API strongly disagrees with the use of this representative composition to establish a universal RACT recommendation. It is inappropriate to use these general averages for determining whether particular existing oil and natural gas sources should be subject to VOC regulation and what is a cost-effective level of RACT control. The gas compositions in oil and natural gas fields in ozone nonattainment areas and the transport region where these RACT regulations will apply vary widely. In many areas, the VOC content is considerably lower than level in EPA's representative composition.

2.4 Evaluation Of Cost Effectiveness For Sites In EPA's Dataset

As noted above, the average VOC content for the GRI data set chosen by EPA to establish the representative composition was 6.8% by volume. The cost effectiveness calculated by EPA for the recommended RACT level of control for fugitive emissions from gas wells, using this representative composition, was $2,111 (considering savings). EPA considers this level to be reasonable. However, the VOC content of the gas compositions for the individual sites in the GRI data set ranged from 0.59% to over 28% by volume. This significant difference in gas composition would have a tremendous impact on the emission reductions, and thus, the associated cost effectiveness. Table 2-2 estimates the cost effectiveness values for each of the sites in EPA's GRI data set.

Table 2-2 Estimated Cost Effectiveness for Recommended RACT for Fugitive Emissions at Gas Well Sites at Sites in EPA's Gas Composition Data Set

Site	VOC Content (vol %)	Estimated Cost Effectiveness
Representative Composition	6.82%	$2,111
GRI1	0.59%	$24,414
GRI2	2.20%	$6,547
GRI3	3.93%	$3,665
GRI4	28.13%	$512
GRI5	7.15%	$2,015
GRI6	8.64%	$1,667
GRI7	7.01%	$2,055
GRI8	10.09%	$1,428
GRI9	6.22%	$2,316
GRI10	2.41%	$5,977
GRI11	3.21%	$4,487
GRI12	2.30%	$6,263

Considering the actual compositions from EPA's own dataset shows that the recommended RACT level for fugitive emissions as gas well sites would result in many gas well sites being subject to controls that have cost effectiveness values above the $5,700 level which EPA has previously determined to be unreasonable for this industry. In fact, four of the twelve sites in EPA's data set, or 25%, would incur what EPA itself has determined are unreasonable costs when considering the VOC emission reduction. This includes one site that would be required to install controls at a cost effectiveness of over $24,000 per ton of VOC reduction.

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2.5 Evaluation Of Cost Effectiveness With Varying VOC Composition In Gas

In order to demonstrate the overall impact of varying VOC content on cost effectiveness, API conducted a succinct analysis for the fugitive emission sources at oil and natural gas sites covered by the CTG. This analysis was conducted using two different costs. The first analysis was conducted using EPA's estimated annual costs as provided in the CTG without adjustment. However, as discussed throughout this document, API believes EPA's costs in the CTG underestimated the actual impact that will occur in several instances. Therefore, the second analysis uses API's updated cost estimates.

2.5.1 Analysis Using EPA Costs

As noted above, EPA's representative gas composition consisted of 6.8% VOC by volume and 18.3% VOC by weight. The cost effectiveness values that were provided in Table 2-1 were based on emissions calculated using these weight percentages. Cost effectiveness values were calculated at varying concentrations of VOC by assuming a linear relationship between VOC emission reductions and the VOC content. Figure 2-1 through Figure 2-4 show the results of this analysis. For reciprocating compressors at processing plants and pneumatic controllers at well sites, EPA estimated that there would be net savings due to the recovery of natural gas. These sources were not included in this analysis.

Figure 2-1 CTG Cost of Control – Reciprocating compressors at Gathering and Boosting Stations

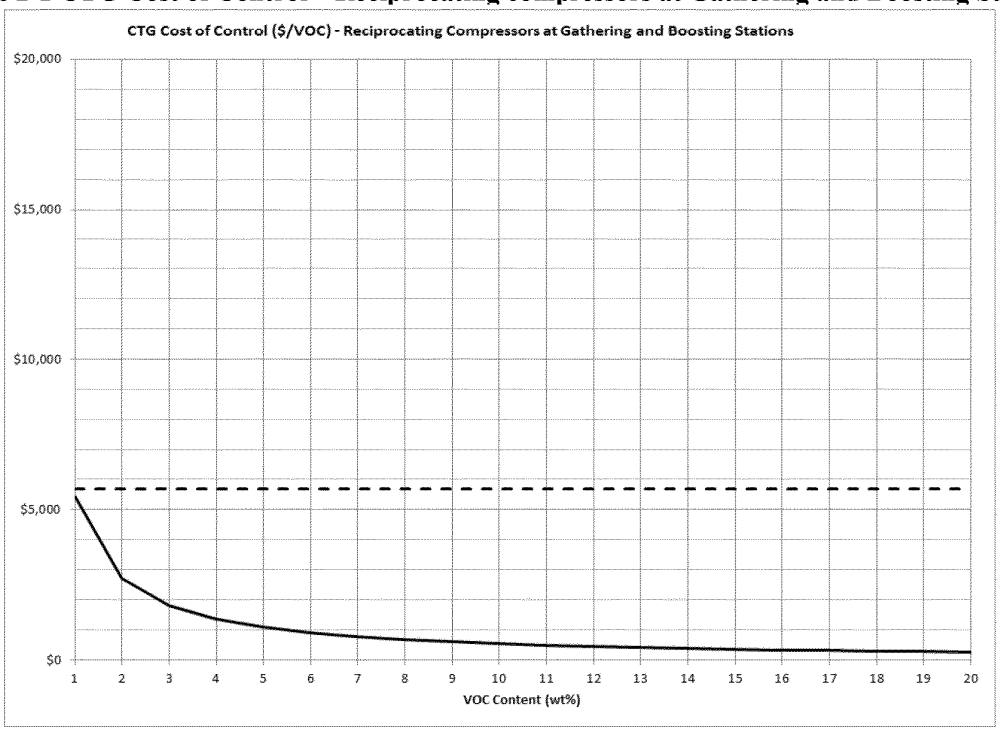

Figure 2-2. CTG Cost of Control – Pneumatic Controllers at Processing Plants

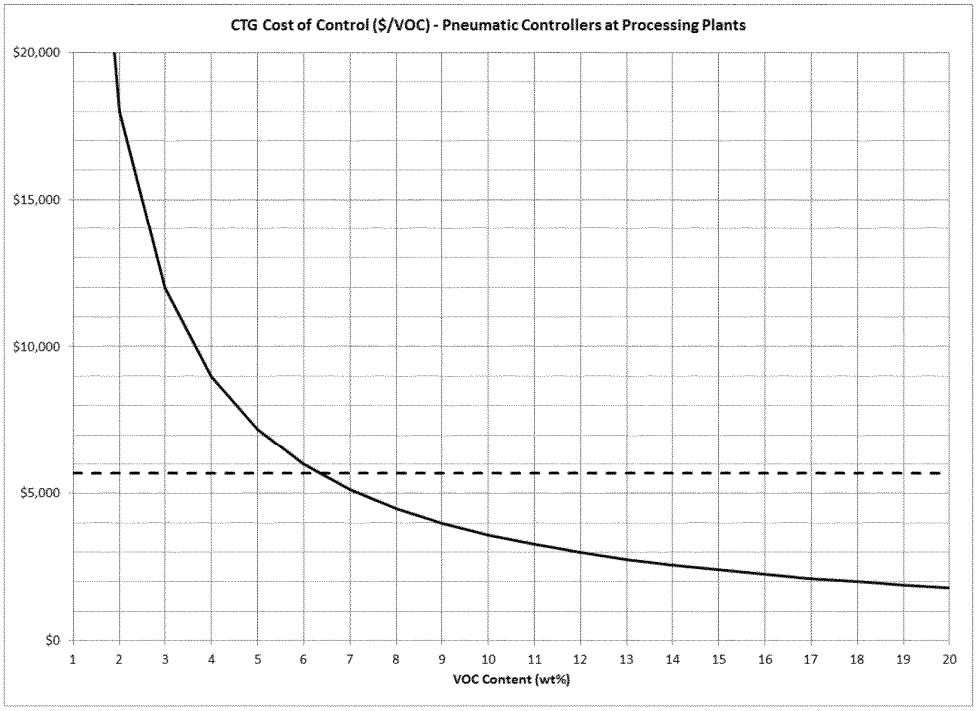

Figure 2-3. CTG Cost of Control – Pneumatic Pumps

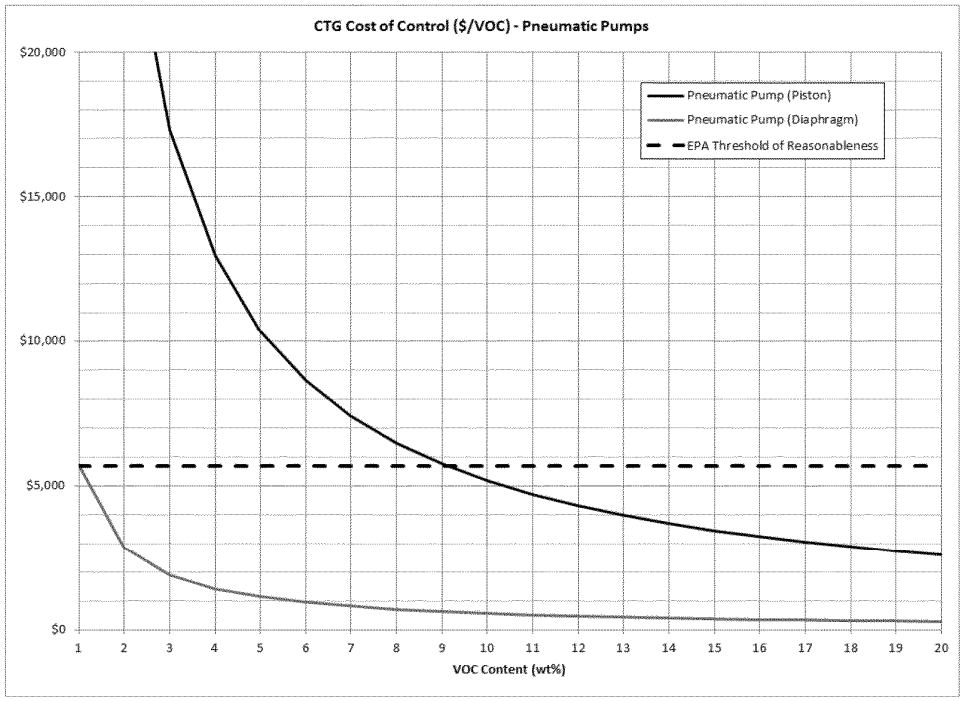

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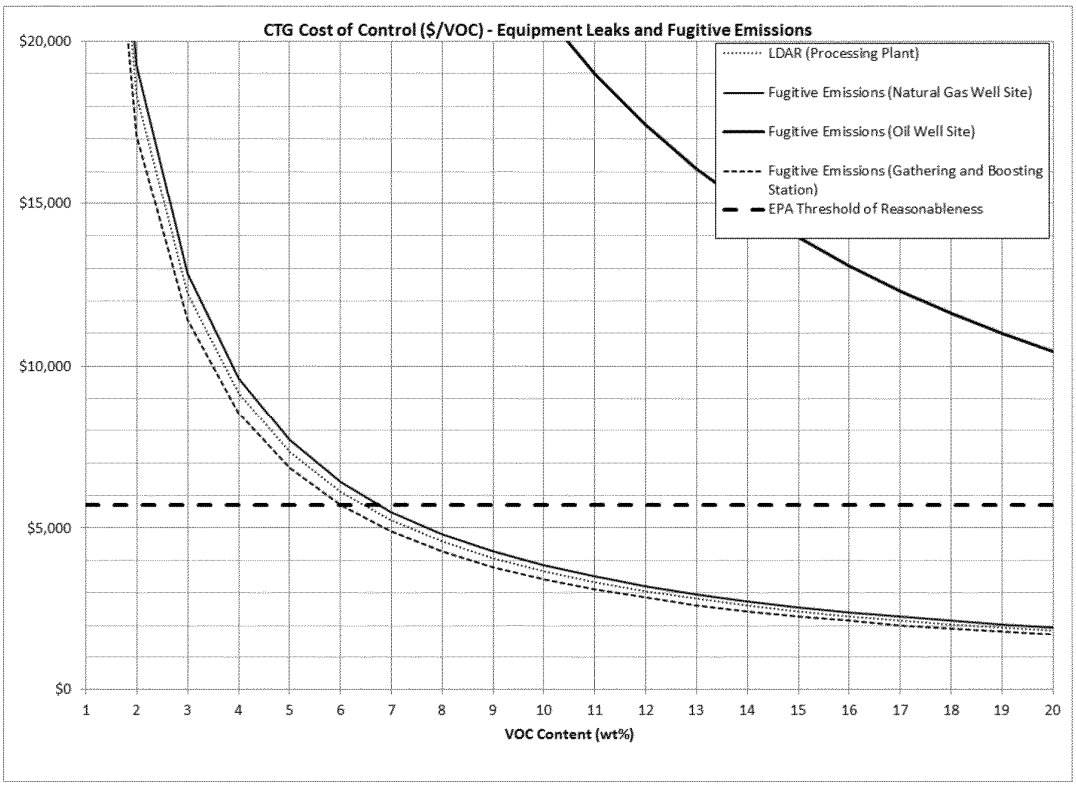
Figure 2-4. CTG Cost of Control – Equipment leaks and Fugitive Emissions



The conclusion of this analysis based on the EPA costs, are as follows:

- For reciprocating compressors at gas processing plants, the cost effectiveness is below $5,700 for VOC concentrations down to 1% by weight.
- The cost effectiveness for fugitive emissions control at oil well sites is greater than $5,700 and thus unreasonable at all VOC concentrations.
- For pneumatic controllers and LDAR at gas processing plants, pneumatic piston pumps, and fugitive emissions at natural gas well sites and gathering and boosting stations, the cost effectiveness rises above $5,700 at VOC concentrations about 6 and 7% by weight.

2.5.2 Analysis Using Updated API Costs

For pneumatic pumps and fugitive emissions from well sites, EPA significantly underestimated the cost of control. API provides detailed analyses of these costs in sections 15.0 and 17.3 for pneumatic pumps and fugitives, respectively. Table 2-3 shows the difference in the annual costs estimated by EPA and the corrected costs based on API members' extensive experience installing and implementing these controls.

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Table 2-3. Comparison of EPA and Updated API Cost Estimates

Source	Annual Costs (including savings)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	$4,359
Pneumatic Pump (Piston)	$201	$5,024
Fugitive Emissions (Gas Well Sites)	$1,599	$7,712
Fugitive Emissions (Oil Well Sites)	$2,079[a]	$8,192[a]

[a] EPA cost is for semi-annual OGI program. API cost is for annual program.

Table 2-4 shows the cost effectiveness calculations using API's updated annual costs. Note that these are based on the VOC emission reductions estimated by EPA using the representative gas composition.

Table 2-4. Comparison of EPA and Updated API Cost Effectiveness Calculations

Source	Cost Effectiveness ($/ton VOC reduction)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	$4,790
Pneumatic Pump (Piston)	$2,007	$50,240
Fugitive Emissions (Natural Gas Well Site)	$2,111	$10,147
Fugitive Emissions (Oil Well Site)	$11,460[a]	$45,511[a]

[a] EPA cost is for semi-annual OGI program. API cost is for annual program.

As seen in Table 2-4, the cost effectiveness values for EPA's draft RACT recommendations for fugitive emissions programs at well sites and for pneumatic piston pumps are well above EPA's reasonableness threshold of $5,700/ton. The diaphragm pneumatic pumps are below this threshold. However, this cost effectiveness is based on the 18.3% by weight VOC content in EPA's representative composition. As discussed above, many areas have gas compositions much lower than this level. Figure 2-5 illustrates the cost effectiveness at different VOC composition levels. As can be seen, the cost effectiveness crosses the $5,700 reasonableness threshold at around 15% VOC by weight.

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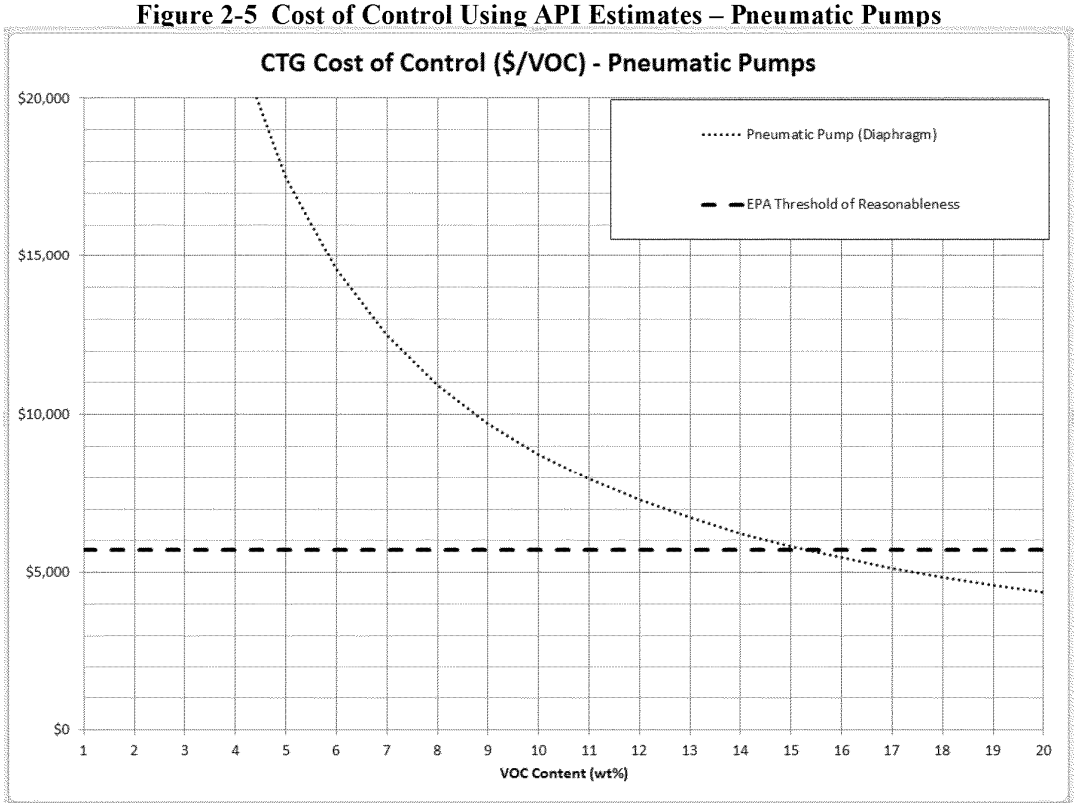
Figure 2-5 Cost of Control Using API Estimates – Pneumatic Pumps



2.6 Many Areas That Will Be Impacted By The CTG And Model Rule Are Low VOC Gas Areas

The oil and natural gas produced in the US varies considerably. This can range from very heavy, thick crude oil (a.k.a. black oil or dead oil) that has no associated natural gas, to light hydrocarbon liquids (a.k.a. condensate) that co-produce VOC-laden gas, to gas that is almost 100% methane with no associated liquids. Each type of formation may have some similarities, but still can have wide variation. Some tight sands behave like sand stone and can produce significant amounts of heavier hydrocarbons. Shale fields run the gamut from wells that produce nearly 100% methane to wells that produce significant quantities of hydrocarbons that are liquid at stock tank conditions. The definitions of the various types of reservoirs are very broad and the defining characteristics have little to do with the reservoir's potential to emit VOC or HAP.

As evidenced by the brief discussion above, areas that produce low VOC gases are likely to be adversely and unfairly impacted by high costs with little VOC emission reduction. However, this is not just a theoretical exercise, as there are numerous areas that will be impacted by EPA's RACT recommendation and model rule and the resulting SIPs where low-VOC gases are prevalent.

There are several active oil and natural gas production areas that are in the ozone transport region or ozone nonattainment areas (or in areas likely to be nonattainment under the new 70 ppbv ozone NAAQS) where the VOC content is very low. These include, but are not limited to the Marcellus, New Albany, Barnett, and Mancos areas. It is estimate that there are over 23,000

wells in these low-VOC areas.[2] While not all of these areas will be in moderate or above ozone nonattainment areas where RACT is required, States may choose to voluntarily implement these recommended RACT requirements to address the VOC from oil and natural gas operations.

In addition, coal bed methane (CBM) typically is produced at low pressures and contains very high percentage of methane (often as high as 97% by volume) and almost no hydrocarbons heavier than ethane. Coal has classically been thought of as a "cap rock", not a reservoir rock. This means that the pore volume (i.e., porosity) is on the order of 0.25%. This very low porosity demonstrates that the only gases that can be stored in the coalbed must be of a size that allows them to be adsorbed to the surface of the coal. Coal has a high affinity to accept CO_2 onto its absorption sites, and a slightly smaller affinity for methane. Heavier hydrocarbons do not "fit" on the adsorption sites (the traces of heavier hydrocarbons that are sometimes reported in CBM fields have come from the very small pore volume, not desorption). Consequently, CBM fields tend to have zero or near zero VOC emissions. There are also several CBM areas that are in the transport region or potential ozone nonattainment areas including, but not limited to, the Black Water, Appalachian, and Uinta areas. It is estimated that there are over 10,000 CBM wells in these areas.[3]

Therefore, a large number of low-VOC sites could be impacted by the RACT rules resulting from this CTG. These sites will be subject to requirements that clearly have costs at a level that EPA has considered unreasonable in relation to the associated VOC emission reductions. Therefore, EPA must include VOC applicability thresholds in the RACT recommendations and model RACT rules to avoid these high cost impacts with very minimal environmental benefit.

2.7 There Is Precedent For VOC Applicability Thresholds In Ctgs And Federal Regulations

There are precedents in many NSPS and other federal regulations where EPA has recognized that the composition of the gas impacts the level of emissions, and thus has included applicability thresholds. This is particularly prevalent for regulations that focus on fugitive emissions, such as the 1983 CTG for fugitive monitoring in Gas Processing[4] (which stated 1% VOC by weight; see section 16.2.8), and multiple NSPS subparts. For example, NSPS subparts VV and VVa only cover equipment "in VOC service," which is defined as equipment that "contains or contacts a process fluid that is at least 10 percent VOC by weight." In other words, equipment components that contact a process fluid with less than 10 weight percent VOC are exempt from the leak detection and repair requirements.

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[2] Marcellus - http://stateimpact.npr.org/pennsylvania/drilling/
New Albany - http://www.in.gov/dnr/dnroil/files/og-NASWellsByStatus1990to2013.pdf
Barnett - http://www.tceq.state.tx.us/assets/public/implementation/barnett_shale/bs_images/bsOilGasWells.png
Mancos - https://www.env.nm.gov/aqb/4C/Documents/Mancosshale_May30_2012.pdf

[3] Black Warrior - http://www.gsa.state.al.us/gsa/cbm/Coalbed%20Methane%20Research.htm
Appalachian – http://www.dcnr.state.pa.us/cs/groups/public/documents/document/dcnr_007916.pdf
Uinta - http://www.blm.gov/style/medialib/blm/ut/vernal_fo.Par.57849.File.dat/GCW%20Cums%20TSD%2003-22-12%20final.pdf

[4] http://www3.epa.gov/ozonepollution/SIPToolkit/ctg_act/198312_voc_epa450_3-83-007_leaks_naturalgas_processing.pdf

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2.8 Conclusion: EPA Must Include Applicability Thresholds Based On VOC Content In The Gas

The discussion above clearly proves the need for EPA to include applicability thresholds based on VOC content in the gas for the RACT recommendations and model rule for several fugitive emission sources where it is proven that the cost effectiveness levels are at unacceptable levels as VOC content decreases.

Specifically, API recommends that EPA exempt the following emission sources from RACT requirements in the CTG if the gas composition at the site exceeds an appropriate threshold. Using EPA's proposed cost estimates that threshold is 7.0 % VOC by weight or less:

- Pneumatic controllers at gas processing plants,
- LDAR at gas processing plants,
- Pneumatic piston pumps, and
- Fugitive emissions at natural gas well sites and gathering and boosting stations.

Considering API's more accurate cost estimates, requirements for fugitive VOC emissions at all well sites and pneumatic piston pumps are not cost effective even using EPA's representative composition. Further, the cost effectiveness for the requirements for pneumatic diaphragm pumps becomes reasonable at 15 % VOC by weight.

3.0 EPA SHOULD APPLY LOW PRODUCTION EXEMPTION TO ALL EMISSION SOURCES AND THIS EXEMPTION SHOULD APPLY WHENEVER THE AVERAGE PRODUCTION OF A WELL SITE FALLS BELOW THE 15 BOE/DAY LEVEL

In Section 9.1 of the CTG, EPA states: "For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrels of oil equivalent per well per day (15 boe/day), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved."

This exemption is specific to the fugitive emission requirements at well sites. However, the reasons stated by EPA are applicable to all emission sources at low-production well sites. Therefore EPA should universally apply this exemption and totally exempt all sources at well sites with average production of less than 15 boe/day from all requirements.

Furthermore, this exemption should apply throughout the life of the well site. In other words, whenever the average production of a well site falls below 15 barrel equivalents it should no longer be subject to any RACT requirements.

4.0 THE CTG DOCUMENT DOES NOT ADEQUATELY COVER ALL THE DATA REQUIRED BY THE CLEAN AIR ACT, WHICH INCLUDE RETROFIT COSTS, OPERATIONAL COSTS, ENERGY REQUIREMENTS, ENVIRONMENTAL IMPACTS, AND FUEL COSTS.

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Clean Air Act Section 108(b)(1) outlines the information that EPA is required to provide to states and other air pollution agencies related to air pollution control techniques for criteria pollutants associated with NAAQS. Specifically, this paragraph states that EPA "shall include data relating to the cost of installation and operation, energy requirements, emission reduction benefits, and environmental impact of the emission control technology. Such information shall include such data as are available on available technology and alternative methods of prevention and control of air pollution. Such information shall also include data on alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions." In this CTG, EPA failed to comply with this requirement. Not only did lead to insufficient information being provided for states, it led EPA to recommend RACT requirements (which are reflected in the model rule) that are not based on accurate information. Throughout these comments, API points out examples of the inadequacies in EPA's cost estimates.

4.1 The CTGS Must Take Into Consideration The Impacts And Costs Of Retrofitting Existing Sources

EPA is not taking into account the significant cost differences between applying a control in a new and existing operations. Applying BSER controls to existing source controls are more expensive (not RACT) for several reasons. As economically feasible is part of the definition of RACT, these costs must be considered.

- Existing controls may not be adequate for CTG compliance. There will be situations where the control device itself is not designed adequately or does not have the necessary uptime and efficiency, or is designed for testing and monitoring. Furthermore the existing control device may not have the monitoring systems required by the CTG. The control device may have been installed for state permitting or regulatory compliance, or maintaining emissions below a threshold, In these situations the existing control device and monitoring systems would need upgrade, potentially significant upgrade. Those costs must be considered by USEPA in their evaluation.
- There may be permitting implications if a flare is the chosen control device.
- New land may be required to add control devices to existing sites.
- Existing vapor recover units, compressors, and storage vessels may require early retirement.
- Existing controls may have remaining useful life and will require early retirement.

4.2 EPA Should Consider The Cost Of Disturbance Of Land To Install New Controls

One of the elements that EPA did not consider in estimating the impacts of these RACT requirements on existing sources is the cost of disturbance of land to install new controls. Industry standards and insurance typically require that combustion devices must be placed 50-150 feet from equipment containing hydrocarbon to avoid explosions from thermal radiation. Due to the spacing requirement for control devices, adding a control device may require additional surface disturbance beyond the existing pad location. There are numerous repercussions of additional land disturbance including:

- Additional land may have to be purchased. EPA has not included in the cost estimate for the control devices the cost of the additional land that would be required.

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- Wetlands may be further impacted requiring additional wetland mitigation and/or a Corps 404 Permit under the Clean Water Act. EPA has not considered the additional cost for wetland mitigation and permitting.
- The additional land needed may encroach on endangered species habitat and may not be allowed to be developed or require additional mitigation. EPA has not considered the impacts of this situation.
- Federal land will potentially require NEPA analysis for the additional disturbance. EPA has not considered the great cost and effort of a NEPA analysis for additional disturbance on Federal land.
- National Historic Preservation Act review may be required for the additional disturbance. EPA has not considered the impact under the NHPA.

4.3 EPA Should Not Require The Same Controls As In The NSPS, Which Is For New Sources

On September 18, 2015, EPA proposed NSPS Subpart OOOOa, which covers all the same emission sources addressed in the draft CTG but for new sources. The Clean Air Act has requirements for evaluating the stringency of controls for the different programs.

Control Technique Guidelines define Reasonably Available Control Technologies (RACT) as the following:

- "RACT emissions limitations are the lowest emissions limitations that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[5]
- While EPA has not set a financial threshold for RACT, per a 2006 EPA memo[6], generally the VOC cost threshold has been approximately $2000 per ton in 1980 dollars ($5,784.37 in 2015 dollars[7]).

New Source Performance Standards outline the Best System of Emissions Reduction (BSER)

- "For purposes of this section, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. (CAA – U.S. Code Title 42 Chapter 85 Subchapter I Part A 7411 (h)(1)."

Despite this difference in statutory authority, in this package of rulemakings, EPA has determined in almost every case that the exact same controls are appropriate for new sources and existing

[5] http://www3.epa.gov/ttn/atw/ctg_act.html
[6] http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf
[7] http://www.bls.gov/data/inflation_calculator.htm

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sources in non-attainment areas. In other words, EPA determined that BSER and RACT are equal. In a few cases (alternative emission limitation for storage vessels, continuous monitoring provisions for storage vessels), the RACT requirements in the model rule in the appendix to the CTG are more stringent than the NSPS. EPA cannot propose the same requirements for BSER and RACT without an explanation. EPA must re-evaluate RACT based on the appropriate criteria and re-issue the draft CTG based on these appropriately conducted analyses.

5.0 EPA SHOULD REITERATE THAT EACH STATE IS ABLE TO ADOPT OTHER EXISTING REGULATIONS IN LIEU OF CTGS AS RACT.

EPA has defined RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). Since the cost effectiveness tabulations are based upon a nationwide average, economic feasibility[8] may vary from state to state. Thus, while EPA considers CTGs to constitute "presumptive" RACT, states are not required to adopt the control measures specified in CTGS as RACT. CTGs may not meet the definition of RACT[9] in terms of being reasonably available for a specific source or source category for a particular area.

Additionally a RACT analysis might conclude different control measures should include the application of a VOC threshold for the implementation within a particular area based upon the sources in that particular area.

According to 2006 Guidance from Harnett[10], in response to a question regarding how to address requirements as part of the SIP where a State determination that sources subject to Federal rules meet RACT by compliance with those requirements:

> To rely on federal rules to meet the RACT requirement, the State must incorporate these requirements into the SIP. For example, a State could incorporate by reference the Federal requirement or could submit a permit that includes this provision as a SIP revision.

The same guidance points out that "a State may rely on control obligations required by federally enforceable permits by submitting the relevant portions of these permits (i.e., the portions establishing the VOC and NOx obligations) as SIP revisions along with a demonstration that such controls are RACT." And "a RACT analysis needs to be done for all CTG sources and all major non-CTG sources. While the CTGs and ACTs provide a starting point for such an analysis, RACT can change over time as new technology becomes available or the cost of existing technology adjusts. States are encouraged to use the latest information available in making RACT determinations, whether that information is in CTGs, ACTs, other guidance that is available or through information submitted during the public review process."

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[8] 1994 guidance indicates that cost effectiveness should be within $160 to $1300 per ton.
[9] Note that API does not agree with this presumption, as there is no basis under the law for the suggestion that EPA's recommendations carry any greater weight than individual state determinations.
[10] http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf

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While a CTG is the starting point for a RACT analysis for a source category covered by a CTG, the analysis must still be conducted to identify "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." EPA should reiterate this obligation and that it is wholly acceptable that such an analysis may conclude that existing regulations satisfy the RACT obligations for a source category and the CTG need not be adopted as written.

An example of where this is especially true relates to monitoring, inspection and performance testing requirements. States typically have their own policies and procedures on these requirements. It is less burdensome for state agency personnel and the regulated community to use the state compliance assurance requirements in lieu of the EPA style requirements included in the model rule. If EPA includes compliance assurance requirements in the model rule, EPA should specifically state in the preamble that state may utilize their own compliance assurance provisions in lieu of those in the model rule.

6.0 API REQUESTS THAT THE CONTROL TECHNIQUE GUIDELINES FOR THE OIL AND NATURAL GAS INDUSTRY AND EPA'S SIP PLANNING GUIDANCE ENCOURAGE STATES NOT TO REQUIRE EMISSIONS OFFSETS FOR MINOR OIL AND NATURAL GAS EMISSIONS SOURCES.

States with marginal non-attainment areas and above are subject to the non-attainment new source review requirements including offsets for increases of emissions for new or modified major stationary sources. While the Clean Air Act only requires emissions offsets in the Non-attainment New Source Review (NNSR) program for major sources in non-attainment areas, some States additionally require offsets for minor sources (Wyoming – WYDEQ). Additionally, some State statutes do not distinguish between major sources and minor sources in their Prevention of Significant Deterioration (PSD) programs applicable to attainment areas with respect to the requirement that new or modified facility does *"not cause or contribute to an exceedance of a NAAQS."* (e.g. Wyoming WAQSR Chapter 6, Section 2(c)(ii)), which can result in air quality offset requirements for minor sources. In rural areas of the US, where most oil and natural gas development occurs, there are limited opportunities to acquire emission or air quality offsets. In the event emissions offsets are required, new oil and natural gas production could be significantly restricted.

With Control Technique Guidelines and NSPS OOOO/OOOOa, the value of additional VOC offsets through beyond-the-requirements control of minor sources is even further diminished. Additionally, virtually no offset opportunities exist for oil and natural gas in rural areas. Thus, API requests that the CTGs and EPA's SIP planning guidance specifically encourage states not to require emissions or air quality offsets for minor oil and natural gas emissions sources.

7.0 STATES SHOULD BE ALLOWED TO DETERMINE WHAT CTGS SHOULD BE APPLIED

The precursors to ozone formation are both VOCs and NO_X. The net impact of ozone formation depends on the NO_X, VOCs, and meteorology for a particular location. As noted in EPA's

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Integrated Science Assessment for Ozone[1] , "Duncan et. al 2010[2] found that O3 [ozone] formation over most of the U.S. became more sensitive to NO_X over most of the U.S. from 2005 to 2007 largely because of decreases in NO_X emissions." Further control of VOC in many areas may result in no discernible ozone reduction. Moreover, control of emissions with combustion devices results in increases of NO_x. The ozone formation for most of the U.S. is NO_X limited; therefore, in most areas of the country adding more NO_X could result in increased ozone formation and implementing a CTG RACT rule would be counterproductive. Analysis for particular areas could find that there was no benefit to ozone reductions with application of CTGs, or in the worst case, such an analysis may find that the net result of controlling VOC emissions with combustion creates *more* ozone since it would add NO_X emissions. EPA should allow the states to determine whether incorporation of the CTGs into RACT SIPs is beneficial through analysis of the air quality for the particular area.

8.0 THE FINAL CTG SHOULD INCLUDE A FEDERAL FRAMEWORK FOR ENCOURAGING VOLUNTARY METHANE REDUCTIONS FROM EXISTING OIL AND NATURAL GAS SOURCES

The incentive to generate voluntary methane reductions from existing oil and natural gas sources will be significantly undercut if EPA adopts CTGs that apply to all existing oil and natural gas sources, including those highly-controlled sources that have voluntarily implemented "best management practices" (BMP) under the Methane Challenge Program. In particular, the adoption of CTGs applicable to the entire source category will trigger a requirement for states to establish RACT standards for all sources, including the BMP-controlled sources, which are located in ozone nonattainment areas and ozone transport areas classified as moderate or higher. The imposition having to change from the BMPs to the RACT requirements once they are finalized will deter many companies from trying to implement the BMPs. Furthermore, once the RACT requirements for the CTGs are included in a state's regulations and State Implementation Plan (SIP), companies will be unable to get offset credits from reduction implemented under a BMP that they make legally and practically enforceable.[11]

To correct this problem, EPA should establish in the final CTGs a federal framework that encourages, to the maximum extent permissible under the CAA, voluntary methane reductions from existing oil and natural gas sources. Such methane reductions are necessary to help ensure

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[1] US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R–10/076F.

[2] Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NOx and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223. http://dx.doi.org/10.1016/j.atmosenv.2010.03.010

[11] The CAA establishes specific rules for the generation of offsets. One key requirement is that the emission reductions must not otherwise be required by some other CAA program or regulation. *See* Section 173 (c)(2) of the CAA (providing that "Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement"). EPA has also established federal guidance providing that to the extent that the emission reductions are in fact required by CAA, those reductions are not "surplus" and consequently may not be used to generate offsets. *See* Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 Fed. Reg. 43,814, (December 4, 1986).

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the achievement of the Administration's goal to cut methane emissions from the oil and natural gas sector by 40-45 percent from 2012 levels by 2025.

This important policy objective can easily be accomplished by narrowing the scope of the oil and natural gas sector subject to the CTGs as well as setting the control thresholds for sources such as storage vessels at a higher level than the NSPS OOOOa levels. Also the final CTGs should include language that excludes sources that have established legally and practically enforceable limits for already implemented BMPs under the Methane Challenge Program from implementing the CTG requirements. Sources that are controlled and following the BMPs for the Methane Challenge that have made them legally and practically enforceable could use the reductions as offsets since they are not under the CTGs. Allowing companies to be exempt from the CTGs that implement the BMPs and make them legally and practically enforceable to get offsets will encourage companies to make reductions earlier than when the would be required for newly designated ozone nonattainment areas under the 2015 ozone NAAQS. Final designations will be issued by October 26, 2017 and the RACT SIPs will be due by October 26, 2019 that would need to include the CTGs. Any reductions made after the designations years of 2013-2015 or 2014-2016 could still be used for Reasonable Further Progress demonstrations and used as offsets as long as they are done before the RACT regulations are put in place. If the CTG fails to provide a source category exclusion for those sources that have voluntarily implemented BMPs for reducing their methane and VOC emissions, the only option available to generate offsets will be for existing sources to achieve VOC reductions that exceed the RACT control levels specified in the CTGs. Under this "RACT-Plus" approach, sources could generate offsets for only a small increment of the total VOC reductions that the company could achieve by the implementation of BMPs under the Methane Challenge Program. This small increment would be those VOC reductions that are in excess of the VOC reduction levels mandated by the state in the VOC RACT standards applicable to affected oil and natural gas sources.

Only a small increment of the total VOC reductions achieved by companies under the Methane Challenge Program would be available to generate a correspondingly small amount of offsets once the CTGs are incorporated into the state regulations. This small amount of offsets may not be a sufficient incentive to encourage robust participation by many companies to achieve substantial methane emission reductions under the Methane Challenge Program above any VOC RACT standard. Furthermore, the states could impose stricter requirements for RACT in their regulations and RACT SIPS beyond the CTGs leaving no further reductions available. The window to do reductions that would still be creditable by making the BMPs legally and practically enforceable but before CTGs are incorporated in the regulations and the RACT SIPs will only be from 2017-2019 giving companies a very small window to acquire offsets.

9.0 THE CONTROL DEVICE TESTING AND MONITORING COMPLIANCE ASSURANCE REQUIREMENTS ARE NOT APPROPRIATE

9.1 Oil and Natural Gas Production Sites Are Unique From Traditional Stationary Sources

The sources that will be subject to RACT rules based on the recommendations in the CTG are unique from typical stationary sources in that they are small sites, located in remote areas, dispersed from each other (often requiring an hour or more travel time between regulated sites), and typically unmanned. These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. Because EPA has "force fit" the testing, monitoring, and other compliance assurance requirements designed for traditional stationary sources to the oil and natural gas industry, the proposed testing and monitoring requirements result in unnecessary

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burden without a commensurate benefit. Sections 9.1.1 through 9.1.3 briefly describe some of the unique aspects of the oil and natural gas industry. Sections 9.2 and 9.3 provide specific examples of the inappropriateness of these requirements and provide recommendations that will ensure compliance and environmental benefit without creating unnecessary and costly burdens on the industry.

9.1.1 Oil and natural gas Production Operating Conditions Are Not Steady State

Oil and natural gas operations are unique due to the dependence on the naturally occurring underground nature of the resource being harvested. This section summarizes some of those unique characteristics and their impact on emission control devices (primarily combustion control devices).

Unlike other industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas is located thousands of feet below the surface and must flow in two or three phases to the surface. Ideally, this flow would occur at a relatively steady rate at a velocity fast enough to suspend small droplets of produced water and liquid hydrocarbons during the vertical ascent to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system. This may occur at times, but it is not typical.

As production declines and velocity in a vertical pipe decrease, the small droplets start to move slower than the gas combine into larger and larger droplets. These eventually form slugs of liquid that must be pushed up the pipe. The increasing back-pressure on the reservoir reduces in-flow, production, and hence velocity. As backpressure on the reservoir increases and the velocity continues to decrease, the liquid column in the wellbore can stop the gas flow until the gas pressure below the slug increases sufficiently to push the liquid to the surface. The management of these wellbore liquids is a major concern throughout the life of a well that mandates changes in both down hole and surface equipment. The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible.

9.1.2 Production Separator Operation

The purpose of the two or three-phase production separator is to separate the two or three-phase flow from the well to make sure that only natural gas goes to the gathering system and only liquid hydrocarbons and produced water are sent to their respective storage vessels. Separators are sized to give sufficient "residence time" to allow the separation of phases to take place. Since the actual mix of gas, oil (or condensate), and produced water varies randomly with time, it is impossible to predict when or how often a given control-action will occur.

The flow into the separator is made up of the fluids that the reservoir produces at any given moment, as modified by the transport of those fluids to the surface. The liquid levels in the separator are maintained by valves (often called dump valves) on the separator outlets to the oil/condensate storage vessel and the produced water storage vessel (although liquid collection systems are sometimes used in lieu of a storage vessel). The dump valves are sized to handle the highest flow rate of liquid that the separator can be expected to receive. Because of the highly

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variable flow conditions, separators normally provide flow to storage vessels in short spurts, typically lasting only seconds, to maintain the required liquid levels and dump cycles may be separated by many minutes, hours, or even days.

9.1.3 Closed Vent System Flow Rate

Gas flow from the storage vessel into the closed vent system (CVS) predominantly results from flashing vapors (resulting from the spurts of liquids from the separator) and dwarfs the working and standing/breathing emissions typical from storage vessels (that occur between spurts). However, the CVS and control device must be sized sufficiently to handle the peak vapor volumes expected. Measuring the flow in CVS causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology (see "Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas", Attachment A). Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds, and be able to go back to zero just as quickly. The hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients. Currently for minerals accounting purposes the Federal government and states do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology.

9.2 The Proposed Testing, Monitoring, And Other Compliance Assurance Requirements Are Inappropriate For The Oil and natural gas Industry

9.2.1 The NESHAP-Level Approach For Compliance Assurance Is Inappropriate And Unrealistic For Oil and natural gas Production Sites

For the most part, EPA has copied the full MACT control device and compliance assurance requirements in NESHAP HH (40 CFR 63, Subpart HH) for the CTG model rule, rather than craft cost-effective requirements tailored to address the unique situations related to RACT for oil and natural gas operations. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for the RACT recommendations. Furthermore, these RACT regulations will apply to dispersed that do not have electricity, may not have automation and may have limited space for existing automation to accept additional inputs into their programmable logic controller (PLC) and remote transmitting unit (RTU). Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH major sources, it is not appropriate to arbitrarily invoke compliance assurance requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for RACT guidelines for the control of volatile organic compounds (VOCs).

Examples of the inappropriateness of invoking MACT compliance assurance requirements for RACT guidelines include but are not limited to:

- E.2(a) of the model rule requires Continuous Parameter Monitoring System (CPMS) for control devices. EPA did not include the cost for installing, maintaining, and operating a CPMS in any of the impact assessments for this rulemaking. Most affected facilities in the production segment of the industry will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable

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logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work cannot be performed by lease operators during normal inspection visits.

- E.2(f)(1) of the model rule requires the operator to establish minimum and/or maximum values for the operation parameter and operate the control device within the range. As explained in section 9.3.4, this requirement is impractical to meet for either manufacturer certified combustors or combustion controls where the performance test is performed in the field, but for different reasons. This requirement is the same as the NESHAP HH requirement located in §63.773(d)(5)(i)(a) & (c).

- Similar to above, E.2.(d)(1)(iii) of the model rule requires that a flare pilot be assured by a heat detection sensor and continuous controller. Section E.2(a) of the model rule makes this appear to be a CPMS requiring all of the assurance provisions of (c), (f) and (g). This requirement is essentially identical to the one in §63.773(d)(3)(i)(C) with the CPMS general provisions located §63.773(d)(1) requiring to meet (4), (6), & (7). Requiring a pilot monitoring device to meet the requirements for a CPMS is extremely burdensome for any rule but is unprecedented for RACT regulations.

- Compliance Demonstrations (E) and Test Methods (F). EPA reference methods that determine percent reduction on a mass basis, as is specified in Subpart HH major source control requirements where the CTG model rule does not specify percent reduction of a pollutant on a mass basis. This causes the measurement of volume that is not practical or in many cases possible with the types of operations and fluid flows typical for these facilities.

9.2.2 Compliance Assurance Requirements Are Unnecessarily Complex

The use of extensive cross referencing both between sections concerning control devices (i.e., E.1 for initial compliance requirements, F for performance testing, and E.2 for continuous monitoring requirements) and various test methodologies renders the requirements confusing and nearly impossible to follow. These segmented requirements unnecessarily add to the compliance burden, and likely to lead to errors and misunderstanding. Companies that operate stationary sources subject to EPA's NSPS and NESHAP regulations may have personnel whose sole job is to understand EPA's complex requirements. However, many companies regulated by these RACT rules are primarily small businesses that do not have this luxury. API members along with the consultants they have hired have had difficulty in interpreting the requirements for control devices as proposed. There is still not agreement of interpretation within API with many of the provisions.

9.2.3 The Compliance Assurance Requirements For Centrifugal Compressors Are Not Justified

During discussions with EPA, API was told that the control device monitoring and testing requirements of the 2012 rule were retained since few centrifugal compressors were expected to require control and that most of these affected sources would be located at more developed facilities, such as Natural Gas Processing Plants. While this statement may sufficiently explain the retention of some of the monitoring provisions, it does not address the practical considerations in complying with the performance test provisions and the identifying parameter ranges required for the continuous monitoring. Although there are few centrifugal compressors that require

control, almost all of the control devices they are connected to also fed with gases from other sources, such as storage vessels, that bring in the impracticality of flow measurement discussed in Section 9.1.3.

9.2.4 The Proposed Compliance Assurance Requirements For Pneumatic Pumps Have Numerous Problems

There are many issues with the proposed compliance assurance provisions for pneumatic pumps. Following are two major issues associated with the compliance assurance requirements. These are discussed at length in Section 15.0

Compliance Assurance Requirements of an Existing CVS/Control Device Should Not Change

EPA determined that the benefit of controlling the discharge of a pneumatic pump was insufficient to justify the installation of a control device, thus the requirement to only connect new pneumatic pumps to existing CVS/control device. Further, EPA only considered the cost of piping the pump discharge to the CVS but did not include costs for additional compliance assurance (see Section 15.3). Most control devices are expected to be installed due to state minor source NSR permits. These permits have their own compliance assurance requirements which are significantly different those in the CTG model rule, resulting in significant additional cost. These additional costs have not been included in EPA's cost analysis, cannot be justified with the low emission benefits achieved, and add no additional environmental benefit. Thus, API recommends that EPA should not require additional compliance assurance requirements in the CTG model rule for a CVS or control device when a pneumatic pump is connected to it (see Section 15.0).

Clarification is Needed When a Pneumatic Pump Must be Connected to a CVS/Control Device

There is significant uncertainty on when a pneumatic pump must be connected to a control device. Control device is an undefined term and defining it is a necessary first step to resolve this issue (see Sections 10.0 and 15.4.5). Another great source of uncertainty is when a boiler or process heater is considered a control device and when it is part of a process (see Section 10.0). API believes that pneumatic pumps should not be required to be routed to a boiler or heater.

Further, the control device and the pneumatic pump may be owned/operated by two different companies (i.e. chemical injection for gathering system corrosion control at a well site). In this case, even though a control device is at the location, it is not available to the owner/operator of the pneumatic pump (see Section 15.4.6). Finally, instances occur where it is not technically feasible to connect the pneumatic pump to the control device (see 15.3.3).

9.3 Compliance Assurance Requirements For Combustion Control Devices

9.3.1 The Proposed Compliance Assurance Requirements May Discourage The Use Of Enclosed Combustors

The design of enclosed combustors intrinsically yields higher destruction efficiencies than flares because of the heater style of burner and protection from cross wind. The enclosure also creates an induced draft of air that aids complete combustion of heavier (higher molecular weight) hydrocarbon streams. Additionally, the enclosure isolates the flame from sight that may cause concern to some members of the public. These benefits sometimes encourage industry to install the high cost internal (i.e., "enclosed") combustor instead of the commonly used open flame flare. Enclosed combustors do have the ability to be performance tested where the open nature of flares do not. It is ironic that EPA is requiring substantially more burdensome monitoring and performance testing requirements for enclosed combustors in the proposed rule, even though

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these combustors have greater environmental benefit than flares. It is counterproductive for the environment to disadvantage enclosed combustors with compliance assurance requirements, just because they are technically feasible. EPA should encourage the use of enclosed combustors by using the same visual inspection requirements as with flares for opacity.

9.3.2 The Continuous Parameter Monitoring System (CPMS) Provisions Are Inappropriate

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. For the reasons stated below, EPA has not justified these requirements and must not include them in the final CTG model rule.

First, these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS.

Second, EPA did not justify the significant additional cost of this continuous monitoring. In fact, EPA did not include costs of monitoring equipment in their capital cost estimates, nor did they include any annual costs associated with the maintenance of this system or for the collection and maintenance of this monitoring data.

9.3.3 The Determination Of CPMS Range Determinations In Field Performance Test Is Technically Impractical

Section E.2(f)(1) of the model rule requires that for any parameter that requires CPMS monitoring, the operator must determine the minimum or maximum value of the parameter that continuously achieves the performance requirements in E.1(a). E.2(f)(1)(i) requires a performance test performed by the operator to determine the minimum or the maximum operating parameter based values measured during the performance test. However, the operator has limited ability to adjust the conditions of the process to test the control device. The performance test must be run at the conditions available when the test is scheduled. The operator is unable to vary the operating conditions to determine the limit of the operating parameter as a manufacturer does when conducting a shop test on an enclosed combustor. Section E.2(f)(1)(i) cannot practically be complied with, because the performance test cannot be completed at the full range of conditions for which the control device will be operated. Furthermore, this goes far beyond what EPA requires for testing control devices for NESHAP HH for area sources that apply to nearly all oil and natural gas production sites and approaches the NESHAP HH requirements for major sources like natural gas processing facilities. For a RACT rule at a remote, unmanned site, it is more reasonable to test the device during the current operating conditions.

9.3.4 It Is Not Technically Feasible To Meet The CPMS Flow Measurement Requirements For Manufacturer Certified Combustion Control Devices

Paragraph E.2(f)(1)(iii) requires that for manufacturer certified enclosed combustors, an operator must install CPMS measurement on the inlet flow to assure that the flow is not greater than the maximum or less than the minimum that the manufacture specifies. As explained in section 9.1.3, the measurement of flow from storage vessels is very difficult, even when only the normal emissions must be measured. With both the minimum and maximum range to be measured, it is

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doubtful if a single instrument can measure both values. The pump flow as well is intermittent low pressure, low velocity/flow and difficult to measure as discussed in Section 15.0.

9.4 Compliance Options For Combustion Control Devices

Section E.1(a)(1) specifies four compliance options that can be used to assure compliance with the combustion control device requirements. These options include (1) percent reduction of the pollutant, (2) limiting the concentration in the exhaust, (3) maintaining a minimum combustion zone temperature, and (4) inject the stream into the flames zone of a boiler or process heater. Comments are provided below on options 1 and 2. As explained in Section 10.0 below, option 4 is a direct conflict with the definition of "route to a process", and therefore, API recommends that EPA remove E.1(a)(1)(iv) and (d)(4)(iv).

9.4.1 Percent Reduction Of Pollutant Should Be Based On Volume Not Mass And Should Not Require Measurement of Flow to the Control

The standards for centrifugal compressors, pneumatic pumps, and storage vessels each require a percent reduction.

- For centrifugal compressors, C.2(a) requires that VOC emissions be reduced by 95.0 percent or greater
- For pneumatic pumps located between the wellhead and point of custody transfer, H.2(b)(1) requires that natural gas emissions by 95.0 percent, and
- For storage vessels, A.2(a) requires that VOC emissions be reduced by 95.0 percent

Note that in none of these standards specify the basis for the 95.0 percent reduction. However the initial compliance demonstration requirements in E.1 add the requirement that this percent reduction in emissions be determined on a mass basis. The associated performance test requirements for calculating percent reduction by weight of pollutants requires the measurement of flow to the control device. These requirements were predominantly adopted from the major source NESHAP requirements in Subpart HH that specify control requirements of 95 percent reduction by weight. While mass reduction requirements may be appropriate and specified by Subpart HH, they are burdensome and impractical for RACT requirements for small, remote, dispersed and unmanned production facilities.

Section 9.1.3 above describes the many difficulties encountered when attempting to measure the flow of vapors to a control device at oil and natural gas production sites. EPA has not explained the reason for prescribing the reduction of pollutants to be determined by weight in the compliance demonstration and performance testing requirements when a mass destruction was not specified as part of the control requirements. Conditions of intermittent high/low flow conditions, variable and turbulent flow, and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API

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requests EPA to determine percent of TOC reduction through a carbon balance methodology similar to that described in EPA's Flare Efficiency Study Report.[12]

The requirement in E.1(a)(1)(i), E.1(d)(1), and E.1(d)(2) should be modified to require reduction of TOC emissions by 95% on a volumetric concentration basis using a "carbon balance" methodology for analysis of the exhaust stack effluent from an "enclosed combustion device" being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO_2 and O_2, and 10 for CO should be specified for testing of the stack effluent gas. The CO_2 measured using Method 3A should be adjusted downward by the latest published atmospheric CO_2 concentration, as reported from the Mauna Loa monitoring site by NOAA's Earth System Research Laboratory, multiplied by the ratio of O_2 measured in the stack effluent as compared to the ambient O_2 content of 20.8 volume %. (3A measured CO_2 (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O_2 (ppmv)/208,000 (ppmv) ambient O_2 concentration).

The percent pollutant reduction or destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(CO_{2c} + CO)/(CO_{2c} + CO + (3*TOC))$$

Where:

CO_{2c} = CO_2 ppmv concentration measured in the stack via method 3A minus the ambient CO_2 ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following table shows this calculation and outcome for an assumed stack effluent composition:

Table 9-1 Assumed Stack Affluent Composiiton

Outlet CO_2	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O2	150,000	
Ambient O2	208,000	
Ambient CO_2	388	

[12]. Technical Report "EPA-600/2-83-052" "FLARE EFFICIENCY STUDY" by Marc McDaniel, July 1983 (see http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf).

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Outlet CO_{2c} from combustion	29,720	Outlet CO_2 - ((Ambient CO_2 X (Outlet O2/Ambient O2))
Destruction Efficiency	99.70%	$(CO_{2c}+CO)/(CO_2c+CO+(3*TOC))$

9.5 EPA Must Revise The Provisions Related To Flares Subject To §60.18

9.5.1 There Are Technical Challenges In Meeting The §60.18 For Flares In Oil and natural gas Production And Gas Processing That Must Be Addressed

Flares are an attractive control device choice for the oil and natural gas industry due to their simplicity, reliability, lower maintenance requirements, and effectiveness in reducing organic compound emissions. The requirements in §60.18 of the 40 CFR part 60 General Provisions were developed by EPA to generally apply to flares. However, these requirements were developed and refined based on industrial flares primarily used at large petroleum refineries and petrochemical plants. As discussed above in section 9.1, there are unique aspects of the oil and natural gas industry that require accommodations in the control device requirements. The following sections suggest changes related to the application of the §60.18 provisions to Subpart OOOO and OOOOa affected facilities that will allow the compliant use of flares in the oil and natural gas industry without compromising their effectiveness in reducing VOC and methane emissions.

9.5.2 The Use Of Electronic Ignition Systems Should Be Allowed

§60.18(c)(2) requires that flares shall be operated with a flame present at all times, as determined by monitoring using a thermocouple or any other equivalent device to detect the presence of a flame.

API continues to believe that an option to use electronic ignition systems should be allowed for the oil and natural gas sector. Since oil and natural gas operations are not always steady state, flares with continuously lit pilots (24/7) can unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emissions stream being burned. An attractive and effective alternative is to allow the use of electronic ignition systems that ensure a flame is present whenever emissions are being routed to the flare.

In addition, many oil and natural gas production sites are remote and unmanned. In these situations, an electronic ignition system has proven to be a more reliable means of ensuring there is always a flame when emissions are routed to the flare than attempting to maintain a continuous pilot.

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903.[13] Presumably this was published because EPA approves of the design, recognizes its benefits and wanted to promote its use in industry. EPA should not forfeit the benefits of this control technology enhancement by disallowing its use. As an established and

[13] http://www3.epa.gov/gasstar/documents/installelectronicflareignitiondevices.pdf

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preferred technology by EPA in the Natural Gas STAR program, operators should not have to petition EPA for approval.

API recognizes the need to ensure that the electronic ignition system is working and that a flame is present at all times when emissions are being routed to the flare. API believes that the existing requirements in §60.18(f)(2) already provides an appropriate requirement: Paragraph (e) states that "Flares used to comply with provisions of this Subpart shall be operated at all times when emissions may be vented to them" and (f)(2) states "The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame." With the simple amendments to F(a)(1) and E.2(d)(1)(iii) shown below, EPA can allow the use of auto-ignition devices while also ensuring compliance.

Specific recommendations for these amendments are provided in section 9.5.5.

9.5.3 Testing Should Not Be Required To Demonstrate Compliance With §60.18(f)(4)

Paragraph 60.18(f)(4) requires that the volumetric flow rate be "*determined by Reference Methods 2, 2A, 2C, or 2D as appropriate*". As a result, a test will be required for every flare used to comply with the CTG model rule. As discussed in section 9.1, the measurement of flow is impractical and potentially impossible at oil and natural gas production sites. In addition, even if these technical challenges were ignored, EPA's estimate of impacts did not include significant costs that would be incurred by the industry.

While not specifically referenced in this paragraph, the provisions in §60.8(c) require that performance tests be conducted on conditions that reflect "*representative performance of the affected facility*." During representative conditions, the exit velocities of the flare at oil and natural gas sites will never approach 400 feet per second. This can be easily demonstrated through the use of engineering calculations rather than testing or direct measurements. Specific changes must be made to F(a) to correct this situation. The recommendations for these amendments are provided in section 9.5.5

The technical challenges related to volumetric flow rate are not unique to storage vessels in the production segment. At many gas processing plants, pressure release devices are often routed to flares along with the emissions from other equipment. While there are typically no emissions from these pressure release devices, they can develop leaks. Under subparts OOOO and OOOOa, these pressure relief devices are subject to §60.482-4a(a) of NSPS subpart VVa. Since these pressure release devices are routed to a "closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device", they are exempt from the LDAR requirements in §60.482-4a(a) and (b), but are subject to the closed vent system and control device requirements of §60.482-10a. Paragraph §60.482-10a(d) requires flares to comply with §60.18. The leaks that would occur from these pressure release devices would be very low, meaning that the difficulties in measuring the flow to these flares results in costly test programs that are entirely unnecessary given the extremely low flow rates. Therefore, API also recommends that the volumetric flow rate for these flares also be allowed to be determined using engineering calculations. API suggests that paragraphs be added to G.3 to address this technical infeasibility situation. These recommendations for these amendments are provided in section 9.5.5.

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9.5.4 Sonic And Other Flares Operated During Maintenance, Startup, Shutdown, And Malfunction Situations Should Not Be Required To Comply With The Exit Velocity Requirements In §60.18(c)(4)

In EPA's September 18, 2015 Federal Register Notice (80 FR 56646), EPA specifically requested comment on the use of pressure-assisted flares in the oil and natural gas industry.

As EPA notes, pressure-assisted, or sonic, flares are designed to exceed §60.18's maximum exit velocity of 400 feet per second. As a result, they do not meet §60.18. Some facilities with potential large volume flows may utilize sonic flares, such as those included at onshore natural gas processing facilities, to control emissions in times of emergency, upsets, or maintenance. Sonic flares offer advantages over traditional low-pressure flares in some applications. For example, some designs allow smokeless operation over the entire operating range without any assist medium. This is a clear benefit for remote areas. Additionally, with no assist medium, energy usage and its related emissions are minimized and there remains no potential for steam/air over-assist. Some designs also offer less low frequency noise and less flame visibility in low profile designs. Sonic flares operate with destruction efficiencies that are at least as equivalent to, and generally greater, than low pressure flares.

Pressure-assisted (sonic) flares are not designed for continuous use, but instead operate in emergency, upset or maintenance situations where high volumes and pressures are sent to the flare. In some scenarios, pressure relief valves subject to LDAR monitoring are routed to sonic flares for the purpose of emergencies or upsets. Maintenance events are also routed to these flares in some cases.

However, a conflict with the velocity limits in §60.18(c)(3) is not limited to the case of pressure-assisted flares. Velocity limits for commonly used low-pressure flares (ground or elevated steam-assisted, air-assisted or unassisted flares) are achievable under representative day-to-day conditions. However, velocity limits for even low-pressure flares can be exceeded under conditions that approach the hydraulic capacity of flares. General application of §60.18(b) to a Subpart without the inclusion of §60.11 or an alternative exemption for periods of emergency, upset or maintenance is problematic.

Flares designed under §60.18(b) may exceed velocity limits during periods of emergency, upset or maintenance. In order to remain in compliance with the velocity limits, flare operators would need to install additional flare capacity for SSM events either by replacing an existing flare or adding additional flares. Therefore, the exemption from the §60.18 maximum velocity requirements should not be limited to pressure-assisted flares, but rather to all flares during periods of emergency, upset, or maintenance. As discussed in section 9.5.6 below, there is substantial evidence that indicates that the performance of flares will be maintained at these higher velocities.

Therefore, in order to allow the use of sonic flares and traditional flares designed under §60.18(b) for the oil and natural gas industry, EPA should exempt flares from the maximum velocity requirements in §60.18(c)(4).

Revisions are needed to F(a) and to G to allow the use of flares in these situations. The recommendations for these amendments are provided in section 9.5.5.

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9.5.5 Recommended Model Rule Changes To Address Issues With Flare Requirements

Following are the recommended rule changes related to the issues discussed above that are related to the requirement that flares used for compliance with the CTG model rule comply with the requirements of §60.18.

G.3

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

E.1

(d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (45) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and F(e).

* * * * *

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

* * * * *

(5) You must design and operate a flare in accordance with the requirements of section F.

F(a)(1)

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

E,2(d)(1)

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in E.1(d)(3).

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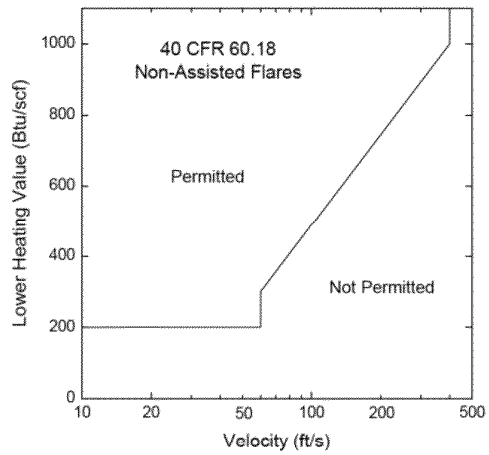
9.5.6 Velocity Limits in §60.18(c)(3) Are Unnecessary To Ensure High Destruction Efficiency in Flares

There is substantial evidence that flares operating with higher exit velocities are effective in reducing emissions. Following is a discussion of this evidence. [14]

Origins of Existing Flare Velocity Limits

The velocity limits in 40 CFR 60.18 were originally promulgated on January 21, 1986 and are graphically depicted below. The figure shows flame exit velocities in feet-per-second (fps) along the x-axis and lower heating value of the waste gas in Btu per standard cubic feet (scf) along the y-axis. A minimum heat content is required of 200 Btu/scf for unassisted flares or 300 Btu/scf for assisted flares up to 60 fps, where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps is reached.

Figure 9-1 Current EPA Flare Velocity Limits



This relationship was developed following a series of EPA sponsored tests conducted in the 1980's that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel[15] test and the 1984 Pohl[16] test. The focus of the 1985 Pohl[17] and 1986 Pohl[18] studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 feet per second (fps) have been included in this analysis.

The 1986 limits appear to originate with only four data points from these tests – the average value at the upper limits of each study. The 60 fps, 300 Btu/scf limit for steam-assisted flares was set

[14] Adapted from "A Review of Flare Velocity Limits in 40 CFR 60.18 and 63.11." Prepared for American Petroleum Institute October 26, 2014 by Scott Evans.
[15] McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983
[16] Pohl, J., et. Al.; "Evaluation of the Efficiency of Industrial Flares: Test Results," EPA-600/2-84-095
[17] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Compostion," EPA-600/2-85-106, September 1986
[18] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: H2S Gas Mixtures and Pilot Assisted Flares," EPA-600/2-86-080; September 1986

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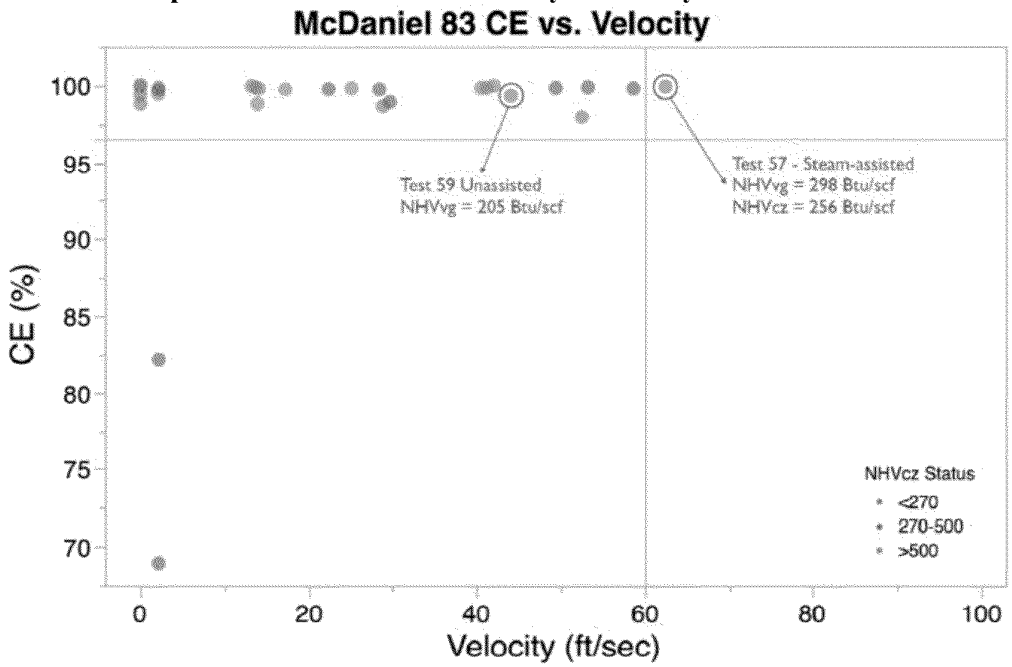
based on a single data point -- McDaniel 1983[15] test 57. The 200 Btu/scf limit for unassisted flares was also set based on a single data point – McDaniel test 59. These tests were performed on an 8.6-inch steam-assisted flare fueled with a propylene/nitrogen mix. The data are shown in

Figure 9-3. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHVVG) is less than 270 Btu/scf, green dots indicate test runs with NHVVG between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

Figure 9-2 A Comparison of Combustion Efficiency vs Velocity for McDaniel 1983

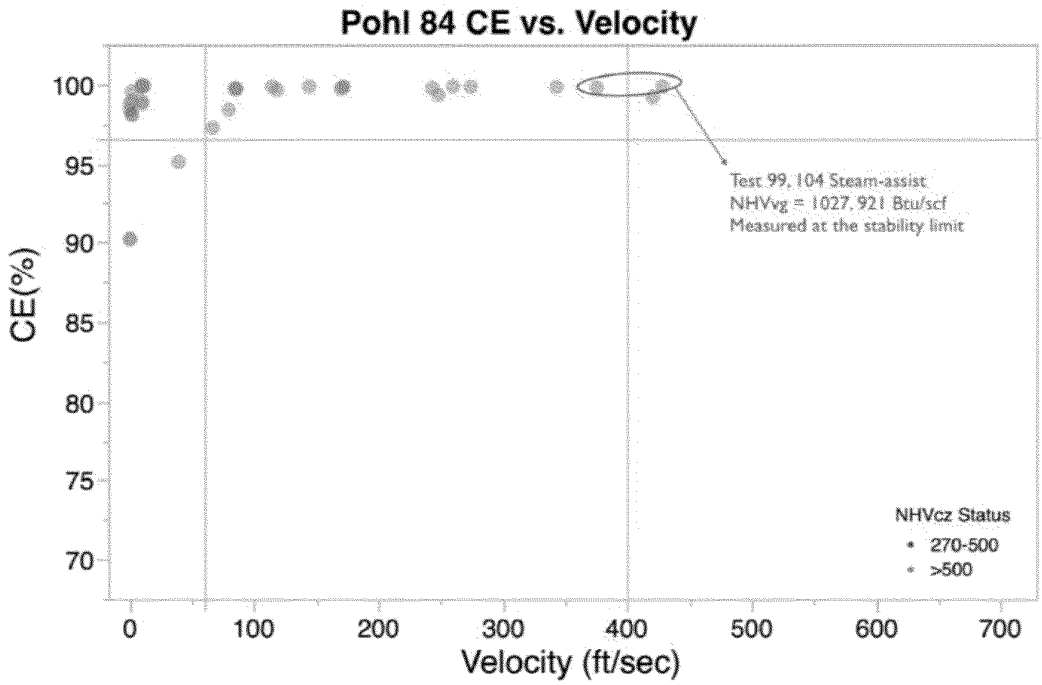


McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.[16] That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in

Figure 9-3. The data are binned by heat content, where green dots indicate test runs with NHVCZ between 270 and 500 Btu/scf and blue indicate test runs with NHVCZ greater than 500 Btu/scf.

Figure 9-3 A Comparison of Combustion Efficiency vs Velocity for Pohl 1984



Similarly to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

High Velocity Flare Test Data

Figure 9-4 shows all data from publically available high velocity flare tests as of October 2014. Some low velocity data are also included to the extent that they were measured during a test series including high velocity data. Data includes the 1980's flare studies referenced above as well as more recent studies (Marathon Garyville[19] and Dow[20]). This data is similarly displayed based upon combustion efficiency (CE) as a function of exit velocity in fps. The data is binned by combustion zone net heating value (NHVCZ) in groups of 500 Btu/scf. Only data with NHVcz > 270 are included.

[19] Clean Air Engineering, "Performance Test of Steam-Assisted and Pressure-Assisted Ground Flare Burners with Passive FTIR – Garyville," March 21, 2013

[20] Varner, V., Kodesh, Z.; "Emission Testing of Pressure Assisted Flare Burners," Presented at the American Flame Research Committee 2014 Industrial Combustion Symposium, September 2014

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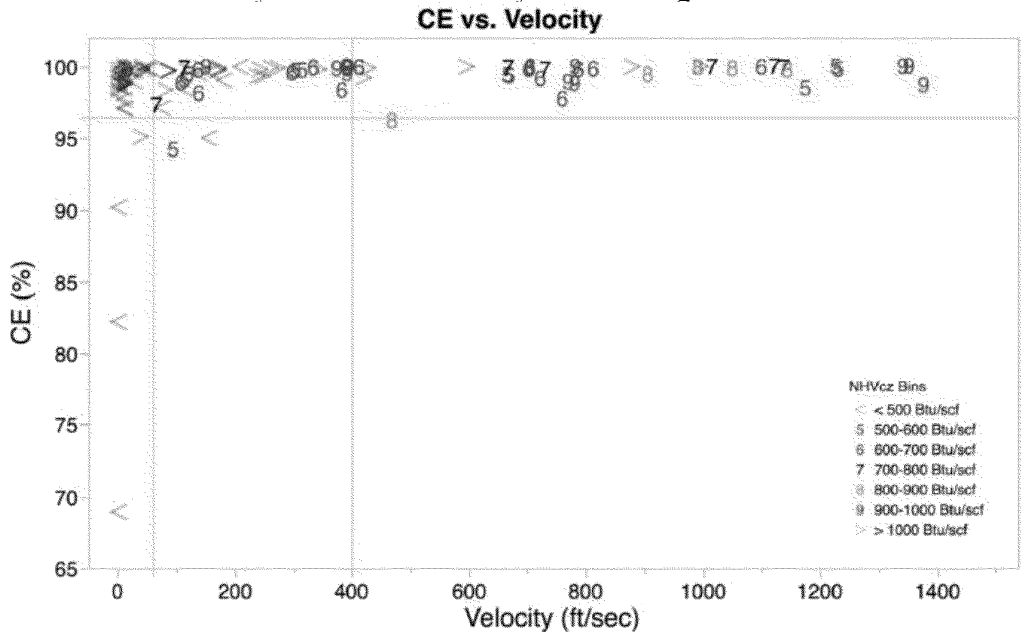
Figure 9-4 A Comparison of Combustion Efficiency vs Velocity for All Publically Available High Velocity Flare Tests binned by NHVcz Range



Almost all of the low velocity data that also have low CE have NHVcz values less than 500 Btu/scf. Additionally, virtually all of the test runs with velocity greater than the current limit of 400 fps, were conducted at NHVcz values less than the current 1,000 Btu/scf limit. This graph clearly shows that high combustion efficiency above the current limits is not only possible, but that it is assured based upon available test data.

Flame Stability

The claim is often made that the reason velocity limits are necessary is to ensure "flame stability." However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

The term "flame stability" simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out. [Pohl 84, p2-3]

Others[21] have defined flame stability in terms of "lift-off", a conditions that occurs when the base of the flame detaches from the flare tip.

While there is no doubt that Pohl's definition results in unacceptable flare performance, there is little evidence that flame lift-off has any correlation either positive or negative to combustion

[21] Shore, D., "Improving Flare Design: A Transition From Art-Form to Engineering Science," Presented at AFRC-JFRC October, 2007.

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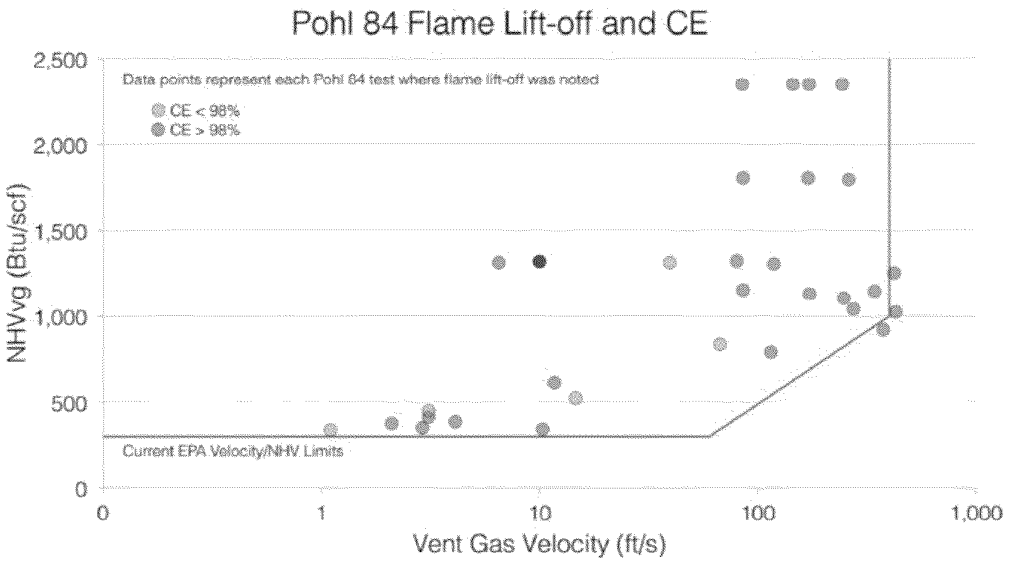
efficiency. Figure 5 shows every data point from Pohl 84 where flame lift-off was noted in the report.

Figure 9-5 A Comparison of Flame Lift-Off and Combustion Efficiency from Pohl 84



27 of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 9-5 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl's definition… a high velocity flame is stable until it goes out.

There is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the "snuff point." Both the Pohl 84 data and the Marathon Garyville data were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

Conclusion

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This paper reviewed data from the data sets used to establish those federal regulatory velocity limits as well as recent high velocity flare test results.

All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion efficiency (>96.5%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.

The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive.

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9.6 While EPA Has Been Testing Various Manufacturer Devices, The Process Has Been Slow

The CTG model rule allows for the use of combustion devices that are tested by the manufacturer which eliminates the need for source testing at the site. This has been allowed under NSPS Subpart OOOO (40 CFR 60, Subpart OOOO) and MACT HH and HHH (40 CFR 63, Subparts HH and HHH), for several years. EPA maintains a list of approved Combustion Control Devices[22] on their website. EPA has also stated that the current "approved list" will be adopted for OOOOa. API requests confirmation of this in the response to comments to reflect EPA's intent.

However, there are several issues with the approval process. First, more than half of the devices listed on the website are characterized as "under review", and they have maintained this status for a long period of time (one or more years). According to one manufacturer, the approval process should be less than a month. The CTG will result in the need for many more combustion devices to control existing sources, which increases the need to shortern the approval process. Closer inspection revealed that incomplete test reports may be a possible cause for achieving "under review" status, and therefore it may not be a fault of EPA's process. However, EPA needs to investigate the cause for these long delays in this approval process and correct them.

Second, manufacturers report that relief from propene testing would decrease the testing costs considerably. The requirement for propene testing for combustion devices that will be used at oil and natural gas production facilities seems illogical as there are insignificant amounts of double bond hydrocarbon compounds in natural gas. API requests that F(d)(2)be modified as follows to allow the use of propane to expedite the approval process.

> (2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

10.0 EPA MUST ELIMINATE THE CONFUSION AND CONFLICT ASSOCIATED WITH "CONTROL DEVICE" AND "ROUTED TO A PROCESS"

It is clear from the model rule control requirements for centrifugal compressors at C.2(b), pneumatic pumps at H.2(b)(4), and storage vessels at A.2(b)(1) that "route to a process" was intended as an alternative to a control device. For example:

A.2(b)(1): Except as required by paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of Section D.1(a), that is connected through a closed vent system that meets the requirements of section D.1(b), and routed to a control device that meets the conditions specified in paragraph (b)(3)(i) and (ii) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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[22] http://www3.epa.gov/airquality/oilandgas/pdfs/mantesteddevices.pdf

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However, the definitions and provisions related to "control device" and "routed to a process" are inconsistent and confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters. The following sections highlight these issues and suggest a recommendation that will eliminate the confusion and conflicts without any reduction in the effectiveness of the rule.

10.1 Definition Of "Routed To A Process" Should Be Clarified

The CTG model rule includes the following definition:

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold.

The use of "routed to a process" is clear as used in connection to a VRU, as these emissions are recycled and incorporated into a product.

This definition also unmistakably applies to situations where the emissions are combusted in a boiler or process heater. There are three different ways in which hydrocarbon vapors can be fed into a boiler or process heater for destruction – 1) vapors routed to the flame zone, 2) vapors routed to the fuel system as a primary fuel, and 3) vapors routed to the combustion air supply as a secondary fuel. For all three of these methods of introducing hydrocarbon emissions into a boiler or process heater the emissions are clearly "consumed in the same manner as the material that fulfills the same function in the process" Further, the emissions are "transformed by chemical reaction into materials that are not regulated materials". However, the CTG model rule is not as clear how this definition applies for boilers and process heaters. EPA must clarify this linkage between "routed to a process" and boilers and process heaters throughout the model rule.

Despite the fact that EPA defined routed to a process/route to a process in a manner that would include all situations when emissions are routed to a boiler or process heater, there are instances throughout the model rule where EPA appears to consider boilers and process heaters as control devices. For example, in E.1(a)(1), EPA includes boilers and process heaters in a parenthetical describing a combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater). Similarly, this same parenthetical description of enclosed combustion device in in E.1(d)(1). Further, in the list of "control devices" exempted from performance testing in F(a), there are several specific boiler and process heater examples that are exempted.

One of these exemptions, specifically F(a)(3), exempts boilers or process heater "into which the vent stream is introduced with the primary fuel or is used as the primary fuel." These seems to indicate that EPA draws a distinction between the three situations described above where emissions are routed to a boiler or process heater (even though they are all three clearly covered by the definition of "routed to a process").

The recommended changes discussed below resolve this conflict.

10.1.1 NSPS Subparts VV And VVa Include The Concept Of "Fuel Gas"

In the rulemakings for NSPS Subparts VV and VVa, EPA has addressed this same basic situation in a clear and reasonable manner. For example, §60.482-4a(c) states that:

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> "Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section."

Further, Subpart VVa includes the following related definitions.

> *Fuel gas* means gases that are combusted to derive useful work or heat.
>
> *Fuel gas system* means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

API believes that this precedent can be utilized to improve the clarity in Subparts OOOO and OOOOa. This recommendation is provided below.

10.1.2 Recommended Change to Definition Of "Routed To A Process Or Route To A Process"

API recommends that the following changes be made to the definition of routed to a process or route to a process" in the CTG model rule.

> *Routed to a process or route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

API further recommends that the following definition of fuel gas be added.

> *Fuel gas* means gases that are combusted to derive useful work or heat.

10.2 Definitions Of "Control Device", "Combustion Device", And "Combustion Control Device"

The confusion discussed above related to boilers and process heaters and routed to a process is acerbated by the fact that the CTG model rule does not define control device. In addition to this situation that needs to be corrected, the model rule requirements for pneumatic pumps make defining "control device" critical. This is discussed later in Section 15.4.5,

As discussed in Section 10.1.2, the definition of "routed to a process" clearly includes routing emissions to a boiler or process heater to be consumed, yet the CTG model rule discusses boilers and process heaters as control devices in other places.

In addition, the situation is further confused as EPA uses the terms "combustion device", "combustion control device", and "enclosed combustion control device" in an arbitrary manner that further confuses the situation. None of these terms are defined in the CTG model rule.

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In conjunction with the recommended definitions in Section 10.1.2**API offers the following definitions to be added to the CTG model rule.**

> *Control device* means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this rule.
>
> *Combustion control device means* a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.
>
> *Enclosed combustion control device* means a combustion control device with an enclosure such that the flame is not an open flame.

This definition of control device, along with the definition of "routed to a process or route to a process" recognizes that routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors. Thus, routing pneumatic pump exhaust or compressor blowdown gas to be used as a fuel gas would not make heaters and boilers using these streams part of a control device.

In addition, the following changes are needed throughout the model rule to rectify the inconsistent usage of these terms throughout. These changes also address the changes related to boilers and process heaters and "routed to a process."

> **E.1**
>
> (a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a combustion control device model tested under section F(d), which meets the criteria in section F(d)(11) and section F(e).
> (1) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~, except for a flare, must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (~~iv~~iii) of this section.
> * * * * *
> ~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~
> * * * * *
> (d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a combustion control device model tested under F(d), which meets the criteria in F(d)(11) and F(e).
> (1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.
> * * * * *
> (iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with

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one of the performance requirements specified in paragraphs (i) through (iii) of this section.
~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

F
(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (~~7~~5) of this section.
~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~
~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~
(~~4~~2) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.
(~~5~~3) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.
(~~6~~4) A performance test is waived in accordance with §60.8(b).
(~~7~~5) A combustion control device whose model can be demonstrated to meet the performance requirements of E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.
* * * * *
(b)(3)(iv) Reserved ~~If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

E.2
(b) Reserved ~~You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~
~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~
~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~
* * * * *
(d)(1)(iv) Reserved ~~For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5°C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~
* * * * *
(d)(1)(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the combustion control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion control device must not

exceed the maximum or be less than the minimum flow rate determined by the manufacturer.
(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the combustion control device.

11.0 THE PROPOSED BY-PASS DEVICE REQUIREMENTS ARE NOT REASONABLE AND WERE NOT JUSTIFIED BY EPA

EPA failed to consider the cost and technical feasibility of the audible alarm and notification via remote alarm at the nearest field office for non-secured by-pass device requirements. A remote alarm at a field office does not add any additional environmental benefit, where an onsite device meets the intent of the alarm requirements. There are several considerations for a field office to receive data from field locations including onsite equipment, programming, and installation and maintenance. Adding an alarm will require installation of new equipment requiring potentially a facility to be shut down and the equipment purged so that "hot work" can be performed to install the equipment which will result in additional emissions. Furthermore, a company would need a remote transmitter unit (RTU) installed or have an existing RTU with sufficient capacity to transmit a signal from the device to an operations center to notify the operations center. There are also cost from programming, installation, and maintenance of the alarm. Equipment and installation costs are several thousands of dollars for each data point, per site, routed into a system, even if existing monitoring equipment is located onsite. Ongoing support and maintenance of the monitored parameter is required to sustain operation

For bypass devices secured with a car-seal or lock-and-key type configuration, the requirement is for visual verification that the device is secured. The requirements for non-secured devices should be similar and only require verification if the alarm - whether audio or visual - has been triggered. Since there is a flow indicator present, the amount vented would be known. Following are recommended changes to the CTG model rule language:

D.1(b)(3)(i)(A)
(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.

D.2(d)(1)
(d) For each bypass device, except as provided for in section D.1, you must meet the requirements of paragraphs (d)(1) or (2) of this section.
(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere. You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/ot visible alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.

12.0 THERE IS UNNECESSARY OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSEM AND FUGITIVE EMISSION REQUIREMENTS

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EPA proposes fugitive monitoring like requirements for closed vent systems, but also includes closed vent systems in the definition of Fugitive Emission Components. This results in CVS being subject to both closed vent system requirements in Section D and the fugitive emission component monitoring requirements in Section I. This creates a situation which is unnecessarily duplicative and redundant. Specifically, EPA has required both optical gas imaging monitoring for the tank cover and the closed vent systems under Section I, as well as annual Method 21 (M21) monitoring and visual inspections for closed vent systems under Section D. This could result in as many as three different leak detection programs at a single facility.

To avoid this conflict, API provides recommendations that will eliminate this overlap while still ensuring that emissions from leaks from closed vent system components are minimized. The problem and API's recommendations are discussed in detail in Section 16.0.

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TECHNICAL COMMENTS

13.0 STORAGE VESSELS

13.1 The Cost Analysis For Retrofitting Existing Storage Tanks With Controls Is Inadequate

In section 4.3.1.2 of the Draft CTG, EPA describes the control option of routing emissions to a combustion device. API agrees that a combustor is one of the technically feasible options to reduce VOC emissions from storage vessels. In this section, EPA estimates the cost impacts of a combustor. These costs are summarized in Table 4-5 of the CTG. However, this cost analysis is inadequate in several respects, ranging from simple mathematical errors to the omission of cost elements that EPA includes in their own guidance. Section 10.1.1 summarizes the background for EPA's cost estimate. This is followed by section 10.1.2, which discusses the numerical errors and section 10.1.3, which shows how EPA omitted costs identified in the EPA OAQPS Control Cost Manual from the analysis.

Note that these corrections do not account for the testing, monitoring, and other compliance costs that are included in the CTG model rule, as discussed in section 9.0. If EPA maintains these onerous requirements in the final CTG, they must update the cost analysis further to include these costs.

13.1.1 *Basis For Draft CTG Cost Estimate For Combustors For Storage Vessels*

EPA evaluated costs for control of vapors from storage vessels as described in the 2012 Technical Support Document (2012 TSD) for NSPS OOOO.[23] As stated in section 7.3 of the 2012 TSD, cost data for a combustor were obtained from an Initial Economic Impact Analysis prepared for the proposed State-only revisions to a Colorado regulation (2008 Colorado EIA),[24] which were assumed to be in 2007 dollars. EPA escalated the costs to 2008 dollars using the Chemical Engineering (CE) Indices for 2007 (525.4) and 2008 (575.4),[25] or a factor of 1.0952. EPA also added estimated costs for operating and maintenance labor. These cost data are summarized below in Table 13-1.

[23] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012.

[24] Initial Economic Impact Analysis for Proposed State-Only Revisions to the Colorado Air Quality Control Commission's Regulation Number 7, "Emissions of Volatile Organic Compounds." September 18, 2008.

[25] Economic Indicators: Chemical Engineering Plant Cost Index. Chemical Engineering Magazine.

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Table 13-1 NSPS Subpart OOOO Cost Analyses for Combustor for Storage Vessels

Cost Item	Basis Year:	NSPS 2012 TSD Table 7-5 2007	(x 1.0952)	NSPS 2012 TSD Table 7-5 2008
Capital Costs Items				
	Combustor	$16,540		$18,114
	Freight and Design	$1,500		$1,643
	Auto Ignitor	$1,500		$1,643
	Surveillance System	$3,600		$3,943
	Instrumentation			
	Auxiliary Equipment			
	Combustor Installation	$6,354		$6,959
	Indirect Installation			
	Sales Tax			
	Storage Vessel Retrofit			
	Subtotal			
	Contingency			
Total Capital Investment		**$29,494**		**$32,302**
Annual Costs Items				
Operating Labor	*labor hours*	130		130
	labor rate	$33.51		$36.70
	supervisory hours	19.5		19.5
	supervisory rate	$52.85		$57.88
	Operating Labor	$5,387		$5,900
Maintenance Labor	*labor hours*	130		130
	labor rate	$33.51		$36.70
	supervisory hours	0		0
	supervisory rate	$52.85		$57.88
	Maintenance Labor	$4,356		$4,771
	Subtotal Labor	**$9,743**		**$10,671**
	Maintenance	$2,000		$2,190
	Pilot Fuel	$1,897		$2,078
	Make-up gas			
	Data Management	$1,000		$1,095
	interest rate (%)	7%		7%
	equipment life (years)	15		15
	CRF	0.1098		0.1098
	Capital Recovery ($/yr)	$3,238		$3,547
	Overhead			
	Administrative Charges			
	Property Taxes			
	Insurance			
Total Annual Costs ($/yr)		**$17,878**		**$19,580**
Control Threshold (tpy)		**6**		**6**
	control efficiency (%)	95%		95%
	emission reductions (tpy)	5.7		5.7
Cost Effectiveness ($/ton)		**$3,136**		**$3,435**

EPA evaluated costs in the draft CTG for control of vapors from storage vessels in a similar manner as for NSPS OOOO, with the costs adjusted to a 2012 basis. EPA referenced a more recent version of the Colorado Initial Economic Impact Analysis (2013 Colorado EIA)[26] for most of the costs, but relied on the cost given in the 2012 TSD for the surveillance system, with an adjustment of 5.69% to account for changes in cost from 2008 to 2012. In that the draft CTG is applicable to existing storage vessels, and these storage vessels would require certain alterations to accommodate the routing of vapors to a control device, EPA added a cost item in the draft CTG for "Storage Vessel Retrofit." The costs in the draft CTG are summarized in Table 13-2, with a comparison to the costs in the 2012 TSD.

13.1.2 Numerical Errors In The Draft CTG Cost Evaluation

There appear to be two numerical errors in the draft CTG cost data. One is an omission of the non-labor component of maintenance and the other is an understatement of the cost of fuel to maintain the pilot flame. The impacts on cost-effectiveness of these two numerical errors are shown in Table 13-3.

Omission of the Non-Labor Component of Maintenance.

Table 1 of the 2013 Colorado EIA includes a cost of $2,197 for Maintenance. This should have been understood as maintenance materials, corresponding to the $2,000 in the 2008 Colorado EIA. As in the 2012 TSD, the Maintenance line item from the Colorado EIA should have been included as a maintenance cost in addition to the cost of maintenance labor.

Miscalculation of the Cost of Pilot Fuel.

The cost of Pilot Fuel is given in Table 1 of the 2013 Colorado EIA as $768, which is substantially lower than the value of $2,078 from the 2012 TSD. A footnote to Table 1 of the 2013 Colorado EIA indicates that the cost was based on a fuel cost of $3.41/ million Btu (MMBtu). A typical high heat value (HHV) for natural gas is 1,028 MMBtu/ million scf (MMscf), or 1.028 MMBtu/ thousand scf. The cost per thousand scf would then be 3.41*1.028 = $3.51/ thousand scf. Various sources give values of pilot fuel consumption ranging from 50 scf/hr[27] to 70 scf/hr.[28] At the lower consumption rate of 50 scf/hr, this would correspond to 3.51*50*8760/1000 = $1,537/year, or twice the cost given in the 2013 Colorado EIA.

Further, this pilot fuel cost (said to be based on the Henry Hub Spot Price in August 2013) of $3.41/MMBtu does not match the assumed VRU cost offset of recovered gas that is priced at $4/Mcf (equivalent to $3.89/MMBtu). While this would not result in a significant increase in the cost of control for a single storage vessel, it could when amplified to include the cost of controls for the entire industry.

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[26] Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, "Emissions of Volatile Organic Compounds," submitted with Request for Hearing Documents on November 15, 2013.

[27] Wyoming Department of Environmental Quality, Division of Air Quality, Proposed Revisions to the Chapter 6, Section 2, Oil and Gas Production Facilities Permitting Guidance, Technical Support Document, September 2013.

[28] U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. http://www.epa.gov/ttn/catc/dir1/cs3-2ch1.pdf

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Table 13-2. NSPS Subpart OOOO versus Draft CTG Cost Analyses for Combustor for Storage Vessels

Cost Item	Basis Year:	NSPS 2012 TSD Table 7-5 2008	Draft CTG Table 4-5 2012
Capital Costs Items			
	Combustor	$18,114	$18,169
	Freight and Design	$1,643	$1,648
	Auto Ignitor	$1,643	$1,648
	Surveillance System Instrumentation Auxiliary Equipment	$3,943	$3,805
	Combustor Installation Indirect Installation Sales Tax	$6,959	$6,980
	Storage Vessel Retrofit		$68,736
	Subtotal		
	Contingency		
Total Capital Investment		**$32,302**	**$100,986**
Annual Costs Items			
Operating Labor	*labor hours*	130	130
	labor rate	$36.70	$32.00
	supervisory hours	19.5	19.5
	supervisory rate	$57.88	$51.03
	Operating Labor	$5,900	$5,155
Maintenance Labor	*labor hours*	130	130
	labor rate	$36.70	$32.00
	supervisory hours	0	0
	supervisory rate	$57.88	$51.03
	Maintenance Labor	$4,771	$4,160
	Subtotal Labor	**$10,671**	**$9,315**
	Maintenance	$2,190	
	Pilot Fuel	$2,078	$768
	Make-up gas		
	Data Management	$1,095	$1,057
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery ($/yr)	$3,547	$11,088
	Overhead		
	Administrative Charges		
	Property Taxes		
	Insurance		
Total Annual Costs ($/yr)		**$19,580**	**$22,228**
Control Threshold (tpy)		**6**	**6**
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Effectiveness ($/ton)		**$3,435**	**$3,900**

Table 13-3. Draft CTG Cost Analyses for Combustor for Storage Vessels –Corrected for Numerical Errors

Cost Item	Basis Year:	Draft CTG Table 4-5 2012	Draft CTG *corrected* Table 4-5 2012
Capital Costs Items			
	Combustor	$18,169	$18,169
	Freight and Design	$1,648	$1,648
	Auto Ignitor	$1,648	$1,648
	Surveillance System Instrumentation Auxiliary Equipment	$3,805	$3,805
	Combustor Installation Indirect Installation Sales Tax	$6,980	$6,980
	Storage Vessel Retrofit	$68,736	$68,736
	Subtotal		
	Contingency		
Total Capital Investment		**$100,986**	**$100,986**
Annual Costs Items			
Operating Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	19.5	19.5
	supervisory rate	$51.03	$51.03
	Operating Labor	$5,155	$5,155
Maintenance Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	0	0
	supervisory rate	$51.03	$51.03
	Maintenance Labor	$4,160	$4,160
	Subtotal Labor	**$9,315**	**$9,315**
	Maintenance		$2,197
	Pilot Fuel	$768	$1,537
	Make-up gas		
	Data Management	$1,057	$1,057
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery ($/yr)	$11,088	$11,088
	Overhead		
	Administrative Charges		
	Property Taxes		
	Insurance		
Total Annual Costs ($/yr)		**$22,228**	**$25,194**
Control Threshold (tpy)		**6**	**6**
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Effectiveness ($/ton)		**$3,900**	**$4,420**

13.1.3 Omission Of Costs Identified In The EPA OAQPS Control Cost Manual

EPA maintains a Control Cost Manual which has the following stated purpose:

> *The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed.*[29]

The EPA Control Cost Manual, then, is expressly intended to provide guidance in the evaluation of the cost of control devices. The costs to be included in the evaluation of a flare as a control device are addressed in Section 3.2, Chapter 1 of the EPA Control Cost Manual. These costs include the following line items for Indirect Annual Costs:

- Overhead 60% of total labor and material costs
- Administrative charges 2% of Total Capital Investment
- Property tax 1% of Total Capital Investment
- Insurance 1% of Total Capital Investment

EPA neglected these costs in both the 2012 TSD and the draft CTG, but has offered no rationale for doing so. The omission of these costs, then, appears to be arbitrary and capricious. The impact of these Indirect Annual Costs is shown below in Table 13-4.

13.1.4 Understatement Of Operating And Maintenance Hours

The EPA Control Cost Manual indicates an allowance of 630 hours per year for operation of a flare, and 0.5 hours per shift for maintenance of a flare. Assuming one shift per day, the estimated maintenance labor would be 182 hours. EPA, however, allowed just 130 hours per year for operating the device and another 130 hours per year for maintenance. In the 2012 TSD, EPA acknowledged the higher level of hours in the EPA Control Cost Manual, but reasoned that operating labor would be lower for these devices when used in the oil and natural gas production sector due to most of the sites being unmanned.[30] However, operating and maintenance hours would be increased for unmanned sites due to the travel time involved in getting personnel to the sites. It is, then, inappropriate to arbitrarily reduce estimated operating and maintenance hours for these facilities. The impacts of increasing the operating and maintenance hours to the levels indicated by the EPA Control Cost Manual are shown below in Table 13-5.

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[29] U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. http://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

[30] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012; page 7-4.

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Table 13-4. Draft CTG Cost Analyses for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

Cost Item	Basis Year:	Draft CTG *corrected* Table 4-5 2012	Draft CTG *corrected, plus Indirect Annual Costs* Table 4-5 2012
Capital Costs Items			
	Combustor	$18,169	$18,169
	Freight and Design	$1,648	$1,648
	Auto Ignitor	$1,648	$1,648
	Surveillance System Instrumentation Auxiliary Equipment	$3,805	$3,805
	Combustor Installation Indirect Installation Sales Tax	$6,980	$6,980
	Storage Vessel Retrofit	$68,736	$68,736
	Subtotal		
	Contingency		
Total Capital Investment		**$100,986**	**$100,986**
Annual Costs Items			
Operating Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	19.5	19.5
	supervisory rate	$51.03	$51.03
	Operating Labor	$5,155	$5,155
Maintenance Labor	*labor hours*	130	130
	labor rate	$32.00	$32.00
	supervisory hours	0	0
	supervisory rate	$51.03	$51.03
	Maintenance Labor	$4,160	$4,160
	Subtotal Labor	**$9,315**	**$9,315**
	Maintenance	$2,197	$2,197
	Pilot Fuel	$1,537	$1,537
	Make-up gas		
	Data Management	$1,057	$1,057
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery ($/yr)	$11,088	$11,088
	Overhead		$6,907
	Administrative Charges		$2,020
	Property Taxes		$1,010
	Insurance		$1,010
Total Annual Costs ($/yr)		**$25,194**	**$36,141**
Control Threshold (tpy)		**6**	**6**
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Benefit ($/ton)		**$4,420**	**$6,340**

Table 13-5. Draft CTG Cost Analyses for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs and Full Labor Hours

Cost Item	Basis Year:	Draft CTG *corrected, plus Indirect Annual Costs* Table 4-5 2012	Draft CTG *corrected, plus Indirect Annual Costs and Full Labor Hours* Table 4-5 2012
Capital Costs Items			
	Combustor	$18,169	$18,169
	Freight and Design	$1,648	$1,648
	Auto Ignitor	$1,648	$1,648
	Surveillance System Instrumentation Auxiliary Equipment	$3,805	$3,805
	Combustor Installation Indirect Installation Sales Tax	$6,980	$6,980
	Storage Vessel Retrofit	$68,736	$68,736
	Subtotal		
	Contingency		
Total Capital Investment		**$100,986**	**$100,986**
Annual Costs Items			
Operating Labor	*labor hours*	130	630
	labor rate	$32.00	$32.00
	supervisory hours	19.5	94.5
	supervisory rate	$51.03	$51.03
	Operating Labor	$5,155	$24,982
Maintenance Labor	*labor hours*	130	182
	labor rate	$32.00	$32.00
	supervisory hours	0	0
	supervisory rate	$51.03	$51.03
	Maintenance Labor	$4,160	$5,824
	Subtotal Labor	**$9,315**	**$30,806**
	Maintenance	$2,197	$2,197
	Pilot Fuel	$1,537	$1,537
	Make-up gas		
	Data Management	$1,057	$1,057
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery ($/yr)	$11,088	$11,088
	Overhead	$6,907	$19,802
	Administrative Charges	$2,020	$2,020
	Property Taxes	$1,010	$1,010
	Insurance	$1,010	$1,010
Total Annual Costs ($/yr)		**$36,141**	**$70,527**
Control Threshold (tpy)		**6**	**6**
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Benefit ($/ton)		**$6,340**	**$12,373**

13.2 The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 TPY VOC

In section 4.4 of the draft CTG, EPA explains that 6 tpy of VOC was selected as the applicability threshold because this level was found to be "a cost effective applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels". Table 13-2 through Table 13-4 showed the cost effectiveness calculation at an emissions level of 6 tpy of VOC.

However, as was demonstrated in section 13.1, EPA's cost estimate for combustors for storage vessels was flawed. After adjusting for these flaws, the cost effectiveness values change accordingly for storage vessel emitting 6 tpy VOC.

As was shown in Table 13-4, the cost effectiveness for a 6 tpy VOC storage vessel is estimated to be $6,340 when the Indirect Annual Costs from the EPA Control Cost Manual are taken into account. This is greater than the value of $5,700/ton that EPA deemed to be unacceptably high in related rulemaking.[31] When the Indirect Annual Costs from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 8 tpy would be more appropriate than a threshold of 6 tpy. This is shown in Table 13-6.

Table 13-6 Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

Total Annual Costs ($/yr)	**$36,141**	**$36,141**
Control Threshold (tpy)	**6**	**8**
control efficiency (%)	95%	95%
emission reductions (tpy)	5.7	7.6
Cost Effectiveness ($/ton)	**$6,340**	**$4,755**

Further, as was shown in Table 13-5, the cost per ton of emission reductions is shown to be $12,373 for a 6 tpy VOC storage vessel when the full labor hours from the EPA Control Cost Manual. This is also greater than the value of $5,700/ton that EPA deemed to be unacceptably high in a related rulemaking.[32] When the full labor hours from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 15 tpy would be more appropriate than a threshold of 6 tpy. This is summarized in Table 13-7.

Table 13-7. Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs and Full Labor Hours

Total Annual Costs ($/yr)	**$70,527**	**$70,527**
Control Threshold (tpy)	**6**	**15**
control efficiency (%)	95%	95%
emission reductions (tpy)	5.7	14.25
Cost Benefit ($/ton)	**$12,373**	**$4,949**

[31] 78 FR 58429 (September 23, 2013).

[32] 78 FR 58429 (September 23, 2013).

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13.3 Adding Control To An Existing Storage Vessel To A Control Device Can Present A Safety Issue

Many existing storage vessels were not initially designed to route emissions to a control device. For these existing tanks, the integrity may not be able to withstand the back pressure from the closed vent system and control device. The high back pressure could result in tank damage or even rupture. Therefore, they will require changes to the tank, or full replacement of the tank, in order to handle the back pressure from the control device and closed vent system without damaging the tank. Most of the storage vessels in the oil and natural gas industry last only 10-15 years maximum and would eventually be subject to NSPS OOOOa due to routine replacement.

13.4 Adding Combustion Control To An Existing Storage Vessel May Cause Negative Environmental Impacts That Are More Significant Than The VOC Reductions

Combustion of gas from storage vessels not only destroys VOCs, it creates NO_X, CO, and CO_2 emissions. EPA acknowledges this on page 4-6 of the draft CTG, as they state that "Combustion and partial combustion of organic pollutants also created secondary pollutant including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates." However, EPA did not attempt to quantify these impacts.

The precursors to ozone formation are both VOCs and NO_X. The net impact of ozone formation depends on the NO_X, VOCs, and sunlight for a particular location. As noted in EPA's Integrated Science Assessment for Ozone[33] , "Duncan et. al 2010[34] found that O3 [ozone] formation over most of the U.S. became more sensitive to NO_X over most of the U.S. from 2005 to 2007 largely because of decreases in NO_X emissions." The ozone formation or most of the U.S. is NO_X limited; therefore, in most areas of the country adding more NO_X could result in increased ozone formation would be counterproductive to the point of CTGs to help reduce ozone formation. Analysis for particular areas could find that the net result of controlling storage vessels actually creates more ozone. EPA should allow the states to determine whether controlling storage vessels creates or reduces ozone prior to having to incorporate the RACT recommendations in this CTG into their SIPs through analysis of the air quality for the particular area.

13.5 EPA's Does Not Define "Maximum Daily Average Throughput"

Paragraph (a) of section A.1 of the model rule states that "The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority". API agrees with this approach, except that the term "maximum daily throughput" is contradictory from both a plain text and mathematical point of view. **API suggests that the following definition be added to section A.6 of the model rule.**

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[33] US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R–10/076F.

[34] Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NOx and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223. http://dx.doi.org/10.1016/j.atmosenv.2010.03.010

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Maximum average daily throughput means the daily average throughput during the 30-day PTE evaluation period that represents steady-state conditions.

13.6 The Lack Of An Alternate Uncontrolled VOC Emission Standard In The CTG Model Rule Leads To Existing Storage Vessels Being Controlled Although Emissions Have Declined Below The Applicability Threshold

Under NSPS subpart OOOO and proposed subpart OOOOa, EPA has allowed for the removal of storage vessel control devices once emissions are below 4 TPY (§60.5395(d)(2) and proposed §60.5395a(a)(3)). In the proposed amendments to subpart OOOO published on April 12, 2013 (78 FR 22126), EPA provided extensive rationale for why it was justified to include this alternative limit for storage vessels.

However, the draft CTG model rule does not include this alternative. API believes that if BSER, as required for NSPS, includes this alternative, then certainly the less stringent RACT should also include it. EPA must either include this alternative 4 TPY limit in the CTG RACT recommendation and model rule, or justify why it is not included.

From a cost effectiveness standpoint, EPA stated that below 4 tpy of VOCs controlling storage vessels was not cost effective under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429).

> *". . . . our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately $5,100 per ton. This cost increases to approximately $6,900 per ton at an emission rate of 3 tpy, and to approximately $10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of $5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy."*
>
> *"In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy."*

For RACT, it would definitely not be cost effective below 4 tpy.

13.7 "Well Completion Vessel" Is Not Defined In The CTG Model Rule, Which Could Lead To Confusion

In section A.6 of the model rule, the definition of "storage vessel" includes the following sentence, "A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule." This sentence contains the following terms, which are not defined in section A.6,

- "well completion vessel",
- "recovered liquids",
- "well",

- "startup of production", and
- "flowback".

The omission of these related definitions makes the applicability of RACT toward well completion vessels unclear.

Since the CTG model rule will apply to existing sources only, API believes that well completion vessels would not be subject, as they would be associated with new wells and regulated under the existing NSPS subpart OOOO and proposed OOOOa as potential new, modified, or reconstructed storage vessel affected facilities.

However, in order to avoid confusion, API recommends that the following definitions be added to section A.6 of the model rule. These definitions are consistent with the existing NSPS subpart OOOO and proposed subpart OOOOa (§60.5430 and §60.5430a).

> *Flowback* means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.
>
> *Recovered liquids* means any crude oil, condensate or produced water recovered through the separation process during flowback.
>
> *Startup of production* means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.
>
> *Well* means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.
>
> *Well completion vessel* means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule.

13.8 EPA Has Not Justified The Continuous Parameter Monitoring Requirements In The CTG

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. As discussed earlier in Section 9.2.1, these NESHAP-level monitoring requirements are not appropriate for RACT. EPA has not justified these requirements and must not include them in the final CTG model rule.

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However, for storage vessels the monitoring requirements in the RACT model rule are even more egregious as these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS. They must be removed from the model rule. **API recommends the monitoring requirements for storage vessels be consistent with those for NSPS subpart OOOOa**.

14.0 PNEUMATIC CONTROLLERS

14.1 EPA Must Clarify That Continuous Bleed Pneumatic Controllers With Bleed Rates Less Than 6 Standard Cubic Feet Per Hour Are Not Subject To Any Requirements Under The RACT Recommendation And Model Rule For Pneumatic Controllers From The Wellhead To The Natural Gas Processing Plant Or Point Of Custody Transfer To An Oil Pipeline

The CTG in section 6 proposes that each continuous bleed natural gas-driven pneumatic controllers is the affected facility for RACT by stating the following:

> "RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs, including but not limited to responsetime, safety and positive actuation, requiring a bleed rate greater than 6 scfh)."

Furthermore, the CTG states on page 6-3:"It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed."

While API appreciates EPA recognizing the inherent low emissions of intermittent vent controllers, this statement could also be interpreted that for the purpose of this CTG that intermittent vent controllers should be considered continuous low bleed controllers.

Section B.1 provides the applicability requirements of the model rule to pneumatic controllers. Specifically for pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, paragraph B.1(b) says that the VOC control requirements apply to each "single continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour."
Paragraph B.2(c) then requires the following:

> *(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.*
> *(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a)(3).*

Section B.1(b) is very clear that the rule only applies to pneumatic continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour. Given the above citations from section 6, it can be interpreted to mean that all existing pneumatic controllers are subject to RACT in the CTG. However, the model rule for pneumatic controllers in Appendix B states that continuous high bleed controllers are the affected facility which is consistent with NSPS but inconsistent with the stated RACT in section 6. API recommends correcting its RACT statement in section 6 to clearly indicate that RACT applies only to continuous high bleed gas-driven pneumatic controllers and that RACT applies only to controllers constructed before August 12, 2011, the proposal date for NSPS which defines new sources.

If instead it is EPA's intent to apply RACT to all pneumatic controllers, this will setup the potential for an operator choosing to delay action until after a RACT rule becomes effective rather than take early action. While RACT is mainly for lowering emissions using emissions control, emission reduction from high bleed pneumatic controllers often requires replacement or when feasible a pilot valve retrofit to make them low bleed or intermittent vent. The cost of retrofit may also be considered a reconstruction of the controller as well in many instances. Replacing a controller with a new one or reconstructing it, will make the controller a new source and no longer an existing source, so would then be subject to NSPS not RACT. If this new replacement or reconstruction occurs before the RACT rule is effective, it could become an existing source subject to all the RACT requirements. Even where existing low bleeds and intermittent vents are already used, an operator may replace them anyway just to ensure being considered a new source rather than an existing source if this CTG doesn't clearly define the dates that separate new sources from existing sources. However, these issues are resolved if RACT applies as we recommend; only high bleed controllers are affected facilities, and existing sources are defined as construction prior to the proposal dates of Subpart OOOO or OOOOa as appropriate.

API disagrees with the CTG recommendation that all controllers should be replaced as described in section 6.5 of the RACT.

The CTG should only stipulate high bleed natural gas pneumatic controllers must be replaced, unless justifiable as consistent with the NSPS. Replacing an existing high bleed controller with a new low bleed controller or intermittent controller would cause the new controller be covered under NSPS and would not be subject to an existing source RACT rule.

API requests that EPA acknowledge this fact and provide a clear statement that continuous bleed pneumatic controllers with bleed rates less than 6 standard cubic feet per hour are not subject to any requirements under the RACT recommendation and Model Rule for pneumatic controllers from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

15.0 PNEUMATIC PUMPS

15.1 Introduction

API appreciates EPA's efforts to simplify the guidelines for pneumatic pump control requirements as well as EPA's recognition that there are limited scenarios for which control of pneumatic pumps will be cost effective. However, from review of proposal and supporting documents, it is clear that EPA did not appreciate some key technical issues as well as some key costs that would be incurred if the rule were finalized as proposed.

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Each of these points is expanded upon in this section, but API recommends that the following exemptions should be added to the proposed CTGs for pneumatic pumps:

- Technical Feasibility – If it is not technically feasible to connect a pump to an existing on site control device, there should be an exemption.
- Small or limited use emission pumps (< 53 thousand scf per year emission rate, which is equivalent to a continuous 6 scf/hour emission rate) rate or any pump operating less than 90 days per year).

Additionally, EPA has proposed overly burdensome and costly testing and monitoring requirements for control systems used to control pumps. If control requirements are retained for any types of pneumatic pumps, the model rule should eliminate testing, monitoring, and recordkeeping requirements for the control device that are triggered solely due to the connection of a pneumatic pump exhaust to the closed vent system or control device. Alternatively, EPA should only require control of pumps when an existing NSPS OOOO/OOOOa control device which is already subject to the same requirements as in the proposed rule is present.

Finally, for many technical reasons, API believes it is important that EPA should clarify in the CTGs that the presence of a heater or boiler should not be considered to be equivalent to presence of control device.

Given that the CTGs mirror the requirements under the proposed NSPS OOOOa, API also appreciates EPA's discussion in the NSPS preamble that recognizes the limitations of solar powered pumps, the typical unavailability of electricity at well sites and other remote sites, and the fact that gas-assist lean-glycol recirculation pumps on glycol dehydration units are not pneumatic pumps. API agrees with EPA's approach of defining the affected source as only pumps using natural gas as the pneumatic power source and located at a site with an existing control device. API also agrees with EPA's approach of only requiring control of new, modified or reconstructed pneumatic pumps on sites with existing control devices (combustion control or vapor recovery). However, API has several important issues with the details of the CTG as proposed.

- EPA inappropriately requires an existing control device/system to meet the closed-vent-system, performance testing, monitoring, and recordkeeping requirements of NSPS OOOOa. This is exacerbated by the proposal to require the same measures as for wet-seal centrifugal compressor affected source control devices.
- API believes the capital cost estimate EPA made is low and that several significant cost items are left out of the cost analysis.
- API believes the estimated emissions per pump for diaphragm type pumps is overestimated and the equal proportional split between piston type chemical pumps and diaphragm pumps is incorrect. Due to the limited time available for comment, API did not have time survey members adequately, but there are many more piston pumps installed than diaphragm pumps.
- Because the cost is underestimated and the emissions overestimated, the control actions required by the regulation are not cost effective in many instances.

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- EPA failed to recognize important design and process factors that could render routing a pneumatic pump to an existing control device technically infeasible or unsafe.
- Some details of the model rule language are unclear or not defined fully.

Each of these issues is discussed in more detail in the following sections.

15.2 Control Device And Closed Vent System Requirements

As written, control devices not subject to Subpart OOOO or OOOOa would be required to be used to control emissions from pneumatic pumps. It is not clear if this was EPA's intent in writing the model rule. From the lack of consideration for performance requirements, performance testing, closed vent system monitoring, recordkeeping, and reporting compliance costs in the economic analysis, it appears that EPA did not intend for control devices not subject to Subpart OOOO or Subpart OOOOa to be pulled into the monitoring, reporting, and recordkeeping requirements under the CTGs. If EPA maintains a requirement to route higher emitting pneumatic pumps to existing control devices, this should not trigger the performance specifications, performance testing, monitoring, closed vent system monitoring, recordkeeping, and reporting requirements for the control device if it is not already subject to regulation under Subpart OOOO or Subpart OOOOa. This change from the proposed approach would address one of the two critical cost elements ignored by EPA when assessing the cost of control; specifically, the costs of testing, monitoring, reporting, and recordkeeping requirements.

EPA should also provide for routing of pump exhaust from glycol heat medium pumps (typically diaphragm type pumps) to a controlled tank or knock-out drum prior to the control device to provide for buffering the intermittent flow when the pump exhaust stroke occurs. This would provide for more stable flow to the control device and piping system and simplify connecting a pneumatic pump exhaust to an existing control system.

The draft CTG unnecessarily and inappropriately requires existing control devices and closed vent systems to comply with the full suite of requirements identical to those specified for control devices and systems on centrifugal compressor affected facilities degassing tank vents if a new, modified, or reconstructed pneumatic pump affected source is routed to the control device. EPA failed to recognize that the majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. Since centrifugal compressors are rarely used in the production segment and new, modified, or reconstructed centrifugal compressors in the gathering & collection, processing, and transportation & storage segments are almost certainly dry seal equipped, the probability is near zero that an existing control device on well sites or remote facilities would already be subject to the centrifugal compressor affected source requirements for closed vent systems and control devices. Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. Even where an existing control device and closed vent system has applicable requirements under Subpart OOOO, these are almost certainly those requirements for control devices and closed vent systems installed on storage tank affected sources rather than centrifugal compressor affected sources and thus would have new requirements under the proposed rule. This could subject an individual control device and closed vent system to a dual set of requirements if the proposed rule is finalized as proposed. Note that this discussion focuses

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on enclosed combustion control devices as sites with VRU's are likely to have electricity and hence no pneumatic pump affected sources.

By requiring existing closed vent systems and control devices to comply with the specified requirements listed in sections D.1, D.2, E.1, and E.2 of the draft CTG retroactively applies unnecessary, burdensome, and costly requirements to existing control devices and systems that were not designed, installed, or intended to comply with these requirements. Note also that none of the additional costs are included in EPA's analysis of the reasonableness of controlling pneumatic pump affected sources and the additional costs are likely to render such control not reasonable - cost analysis details are presented in a separate section of these comments.

- Section D.1 and D.2: An existing closed vent system may not be designed or constructed to meet the standard of "no detectable emissions" specified. Again, this may force retrofit or replacement of the existing piping system to enable meeting the "no detectable emissions" requirement.
- Section E.1: Existing control devices and the piping to them are not likely to have the necessary ports installed to enable performance testing as specified and would have to be taken offline in order to retrofit them if retrofit is even possible.
- Section E.2: Existing control devices are unlikely to have all of the monitoring instruments and capabilities required for continuous compliance demonstration as required and these would have to be retrofitted to the control device. Again, retrofit may not be possible which would leave an operator with no avenue to comply without installing a new control device which EPA already found to be not reasonable from a control cost standpoint. Additionally, the data monitoring, logging and averaging required under E.2.c would require either installation of an entirely new monitoring system or tying the monitoring devices into an existing automation system programmable logic controller (PLC) which may not have the number of input ports necessary nor have the memory and computing power necessary. Due to the typical lack of electrical power, the installation of a monitoring system would also require installation of a solar power system with the necessary power to operate the system and the necessary battery back-up to assure adequate data recovery.

Requiring control devices and covered vent systems, where a pneumatic pump affected source is routed to them, to comply with the performance testing, continuous monitoring, and associated requirements of the draft CTG is not necessary. The exhaust from a pneumatic pump affected source is the same natural gas used for the pilot flame in a combustion control device and as fuel for a boiler or heater. It is not difficult to combust and should not require the same rigor of demonstration for more difficult to combust compounds. In general, the low molecular weight straight chain aliphatic hydrocarbons that characterize the natural gas industry, including associated gas, are easy to combust.

To address the issues regarding retroactive application of the requirements in sections D and E of the CTGs to existing control devices and closed vent systems not already subject to the requirements proposed, API recommends EPA take one of the following approaches.

- Maintain the current definition of pneumatic pump affected source and require that the existing control device and closed vent system comply with whatever existing requirements for testing, monitoring, and reporting exist for the particular site/control device and closed vent system.

-or-

- Redefine the pneumatic pump affected source as only those new, modified, or reconstructed natural gas powered pneumatic pumps installed at a site with an existing control device that is already subject to the requirements contained in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a proposed in the rule.
- To assure the integrity of the newly installed piping routing a new, modified, or reconstructed pneumatic pump affected source to an existing closed vent system or directly to the control device EPA could require an annual leak inspection with an Optical Gas Imaging camera for the newly installed piping to an existing control device or closed vent system.

15.3 Technical Basis For RACT Recommendation

15.3.1 EPA Underestimated The Cost Of The Proposed Control Strategy Which Renders Is Not Cost Effective In Many Situations

In the cost analysis for the proposed control strategy for pneumatic pumps, EPA incorrectly only listed a one-time capital cost impact of $2,000 for the design and installation of piping to route vapors from the exhaust of a pneumatic pump to an existing control device. This value was based upon Natural Gas Star program data.[35] Using a 7% interest rate, EPA estimated the annualized cost of controlling a pneumatic pump at $285/year. This value is too low and does not include significant cost items required by the rule. As an example, EPA assumed a cost of $23,252 for tying a wet-seal centrifugal compressor seal-oil degassing tank into an existing control device. (See Section 8.4.4.3 of Technical Support Document for NSPS Subpart OOOOa and Table 5-8 in the draft CTG document.) The low pressure nature of both pneumatic pump exhaust and a seal-oil degassing tank are similar. Unfortunately, the discussion of pneumatic pump control and seal-oil degassing control is not detailed enough to understand the difference in EPA's cost estimates.

API believes the average capital cost (inclusive of engineering) that would be incurred for design evaluation, designing, and construction of the piping to tie a pneumatic pump into an existing control device/system would be closer to $5,800 and would vary considerably from site to site.

Following are the details of API's initial capital cost estimate.

- Collecting the site specific information on an existing control device/system and performing an engineering evaluation of the ability to safely and technically add pump exhaust gas to the control device/system. 8 hours of engineering time at $185 per hour = $1480.
- Evaluating the specific pump's ability to tolerate the exhaust backpressure necessary to route to the existing control device/system; designing the piping necessary to route a pump exhaust to the control device/system; specifying materials, connection points, and connection types for routing a pump exhaust to the control device/system; and writing a work-order and procedure for connecting. Eight (8) hours of engineering time @ $185 per hour = $1480.

[35] http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf.

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- Ordering and collecting materials for installing the piping, commissioning a contractor to perform the work, and overseeing the work. Six (6) hours of construction specialist time at $140 per hour = $840.
- Travel to the site, installation of the piping for tie-in, verification of the proper functioning of the tie-in and travel from the site. One day of a contract construction crew time at $2,000 per day = $2,000.

Utilizing EPA's assumed 7% interest rate, this equates to an annualized initial capital cost of $826 rather than EPA's value of $285.

In addition to underestimating the capital costs of routing the emissions to a control device, EPA did not consider other significant initial and reoccurring costs that would be incurred. The draft CTG requires an existing control device and closed vent system with a pneumatic pump routed to them to comply with the same performance testing, closed vent system, continuous monitoring, and recordkeeping and reporting requirements applicable to closed vent systems and control devices specified for centrifugal compressor affected facilities. The majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. The probability is near zero that an existing control device subject to the centrifugal compressor affected source requirements for closed vent systems and control devices will be on a site where a pneumatic pump source is located.

Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. As such, costs not included in EPA's analysis are:

- The costs for an initial M21 demonstration that the closed vent system, at a site not already subject to the requirements under Subpart OOOO, is operating with no detectable emissions.
- The costs for initial and periodic performance testing of a control device that is not already subject to the required performance testing.
- The costs for monthly smoke inspections, including travel to and from the site for a trained visual smoke inspector.
- The costs for design, installation and maintenance of a parametric monitoring system.
- The recordkeeping and reporting cost.

The table below provides a more complete estimate of the costs associated with implementing the proposed rule requirements for pneumatic pumps. This table reflects the true cost of compliance with the CTG, including potential source testing, the need to install monitoring equipment, and the costs of conducting recurring inspection and equipment maintenance that would all be triggered by the proposed compliance requirements. Note that none of the performance testing exemptions listed in E.2(b) are considered. It should be noted that:

- Heaters with a design capacity of 44 MW (150 million BTU/hr) will not occur in the types of sites where pneumatic pump affected sources will be used

- Heaters used at well sites and other remote sites are likely to be seasonally used, or have intermittent firing dependent on heat demand and hence will not be able to accept the exhaust gas from a pneumatic pump as part or all of the fuel at all times
- As discussed previously, an existing control device is almost certainly not already subject to the performance testing requirements of the CTGs and hence not manufacture certified.
- Hazardous waste incinerators or hazardous waste fueled heaters will not occur at the type of sites where pneumatic pump affected sources will be used.

Table 15-1 Pneumatic Pump Control Cost Table

Cost Item	***Initial Cost***	***Annualized Cost***
Capital Costs (including engineering)	$5,800	$826
Option 1 Combustor Testing (repeat each 5 years)	$6,000	$1,200
Option 2 Process Heater Testing (repeat each 5 years)	$6,000	$1,200
Annual M21 & Visual CVS Inspection *(Contractor or Trained Technician - ½ day with vehicle)*	$600	$600
Monthly 15 min Smoke Check (trained operator inspection - $160/month)		$1,800
Flow Monitor, Thermal Dispersion Meter	$5,000	$712
CPMS - install measurement device and solar panel	$9,000	$1,282
CPMS - Annual Maintenance (contractor 1/2 day)		$600
Annual CPMS Auditing (trained instrument technician complete with equipment and vehicle - 1/2 day)		$600
Scenario		***Annualized Total***
Sites with Affected Pneumatic Pumps & Combustor field performance test		$6,908
Sites with Manufacturer Certified Combustor (no performance test)		$6,420
Sites with Affected Pneumatic Pumps (& Process Heater performance test)		$6,908
Sites with existing Subpart OOOO or OOOOa affected storage tank with control device		$3,308
Sites with existing Subpart OOOO or OOOOa affected compressor with control device		$826

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Table 15-2 Retrofit Costs for Control Devices

Cost Item	*Initial Cost*	*Annualized Cost*
Retrofit control device with new or relocated ports to enable performance testing per Section F. (likely to occur)	$3,000	$427
Retrofit closed vent system to meet "no detectable emission" requirement per Section D.1(b) (less likely to occur)	$3,000	$427

Table 15-3 Average Pneumatic Pump Emission Rate (Reproduced from TSD)

	Tons/year Methane	Tons/year VOC
Piston Pump	0.38	0.11
Diaphragm Pump	3.46	0.96

Combining the complete estimate of actual costs for routing a pneumatic pump affected source to an existing control device with the emission estimates for piston pumps and diaphragm pumps from the CTGs and Technical Support Document (repeated in proposed NSPS OOOOa rule preamble) yields the following tables of control cost per ton for VOC.

Table 15-4 Piston Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

		Single Pollutant Approach
Production Piston Pumps	***Scenario***	**VOC Only**
	Sites with Affected Pneumatic Pumps & Combustor field performance test[1]	$62,797
	Sites with Manufacturer Certified Combustor (no performance test)	$58,362
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$62,797
	Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$30,070
	Sites with existing subpart OOOO or OOOOa affected compressor with control device	$7,509

1. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

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Table 15-5 Diaphragm Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	Scenario	Single Pollutant Approach
		VOC Only
Production Diaphragm Pump	*Sites with Affected Pneumatic Pumps & Combustor field performance test*[1]	$7,196
	Sites with Manufacturer Certified Combustor (no performance test)	$6,687
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$7,196
	Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$3.446
	Sites with existing subpart OOOO or OOOOa affected compressor with control device	$860

[1.] Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard cost effectiveness, the proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**."

As illustrated above, for piston pumps, the control costs exceed the reasonable cost of control per ton for all possible scenarios.

For diaphragm pumps, the cost effectiveness values shown above are lower due to the higher emissions. However, as discussed further in 15.3.4, diaphragm pumps are generally used for heat tracing and as such are not used everywhere and, when they are used do not operate year round. Using a more realistic estimate of 4 months of operation per year, the emissions from these pumps are actually 1/3rd the level assumed by EPA. The table below reflects the cost effectiveness of controlling diaphragm pumps after accounting for their non-year round operation.

Table 15-6 Diaphragm Pump Control Cost Effectiveness (assuming 4 months of annual pump operation)

		Single Pollutant Approach
	Scenario	VOC Only
Production Diaphragm Pump	*Sites with Affected Pneumatic Pumps & Combustor field performance test*[1]	$21,587
	Sites with Manufacturer Certified Combustor (no performance test)	$20,062
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$21,587

Sites with existing subpart OOOO or OOOOa affected storage tank with control device	$10,377
Sites with existing subpart OOOO or OOOOa affected compressor with control device	$2,581

[1.] Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 15-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

After accounting for the non-year round operation of pneumatic pumps, the only reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the CTGs. As explained in more detail earlier in these comments, the probability of this occurring is near zero.

This illustrates the need for EPA to revise the draft CTG approach to performance testing and monitoring for control devices and closed vent systems used for pneumatic pump affected sources as previously explained earlier in these comments.

It is important to note that the above costs assume that the control device and closed vent system existing on site has enough design margin to accommodate the tie-in of a pneumatic pump and that such a change to site configuration does not trigger the need for a revision to the site's air permit.

15.3.2 EPA Did Not Consider or Provide For Instances Where Routing A Pneumatic Pump Affected Source To An Existing Control Device Is Not Technically Feasible Or Where The Control Device Belongs To Another Party

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

In some instances an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

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EPA should provide exclusion in the CTGs such that routing a pneumatic pump affected source to an existing control device or closed vent system is not required if it is not technically feasible or if the control device is not owned and operated by the site operator. Proposed updated rule language is included in 15.4.1.

If needed, EPA could provide provisions in the rule for an operator to make an engineering determination that an existing control device cannot technically handle the additional gas from a pneumatic pump affected source exhaust, document this determination, and make such a determination available for inspection by EPA or other competent authority.

15.3.3 EPA Did Not Consider How CTG Requirements to Route Pneumatic Pumps To Control Devices Can Potentially Trigger Permitting Requirements.

Under draft CTG, EPA is requiring that the exhaust from pneumatic pumps be controlled by control devices if those devices are present on site.

EPA's analysis of the proposed approach to pneumatic pumps has ignored the fact that such an action may require amending the air permit for a facility simply due connecting a pump to a control device. In many cases, the act of tying a new stream into a combustion control device will result in a change in emissions from a site due to the rerouting, which can trigger permitting. Local permitting requirements are very sensitive to the reality that control devices are subtle and complex engineering structures that have very real physical limits. As discussed above, EPA's proposal for natural gas pneumatic pumps seems to ignore these physical realities.

EPA has not accounted for any time or expense associated with this permitting action, nor have they considered any of the additional burden on permitting authorities. These impacts should be quantified and considered prior to finalizing the CTG requirements that may trigger state permitting requirements. One alternative to this concern is to revise the affected source criteria so that a pneumatic pump would not be an affected source, if it was connected to a control device on site. This could be accomplished by revising the text of H.1 as follows:

> Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment ~~for~~ which has not been connected to a control device when one is located on site.

An additional advantage of this approach is that it clearly removes the addition of monitoring and performance testing currently in the proposed rule. As discussed in Section 15.3.1, these costs were not included in EPA's cost effectiveness analysis, nor should compliance assurance requirements from OOOOa be required for a control device that was installed for another purpose.

15.3.4 EPA Overstated The Emissions, And Therefore The Benefits, Of The Proposed Requirements For Pneumatic Pumps

EPA has overestimated the emissions from diaphragm pumps. As EPA notes in Section 7.2.1 of the CTGs: "Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks." As such, these pumps only during the winter season which represents a fraction of the year on average. Yet, EPA has assumed these pumps operate 8,760 hours per year when estimating emissions. This assumption grossly inflates the actual emissions from these sources. A more realistic estimate would be that these sources would operate 3-4 months during the course of the

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year and rarely more than 8 months per year. See discussion of cost effectiveness values in Section 15.3.1, including consideration of operation of diaphragm pumps for 4 months/year.

Diaphragm pumps are also used intermittently to transfer bulk fluids such as engine oil or emptying a sump. When used for these types of service they do not run for long periods, are not large emission sources and should not be covered by the CTGs.

API recognizes the need for EPA to simplify analysis for assessing cost benefits for the development of the CTGs. EPA presents values in Section 7 of the CTGs which are based on a number of assumptions. It should be noted that the exhaust rates from pneumatic pumps are, in reality, based on assumed pump rate, a gas-supply pressure, and a pump model. All of these values vary considerably from site to site and even from pump to pump on a given site. When one reviews several manufacturer's pumps, it is readily apparent that they all have a multiplier factor for calculating required supply pressure and allowable exhaust pressure and these factors vary by over two orders of magnitude from one pump model to the next.

15.4 Applicability/Definitions

15.4.1 The CTG Should Have An Exemption For Limited Use/Low Emission Pumps Such As Chemical Injection Pumps

API believes EPA's intent to regulate pneumatic pumps that have lower emission rates than continuous low bleed pneumatic controllers is inappropriate. EPA has previously determined that continuous bleed pneumatic controller devices emitting less than 6 scf/hour did not require control and EPA continues to support that position in the NSPS OOOOa rule proposal. EPA's Technical support document shows the assumed emission rate from pneumatic piston (chemical and methanol) pumps to be 2.48 scf/hour, which is less than half the 6 scf/hour threshold for continuous bleed pneumatic controllers. The cost effectiveness of controlling such low emitting pumps is substantially above EPA's assumed $285/ton as described Section 15.3.1. Piston pumps in services with emissions below 52,000 scf/year (equivalent to 6 scf/hour annualized) should be exempt due to the low volume of gas exhausted. Demonstration of emissions below this threshold should be a one-time engineering calculation for individual pumps or a class of pumps in similar service - for example chemical/methanol pumps below a pressure & volume combination which would yield exhausted volumes above the threshold.

There are also natural gas-driven pneumatic pumps, typically diaphragm pumps, that are used intermittently to transfer bulk liquids. These are generally either manually operated as needed or are triggered by a level controller. For instance, there are engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, separator knockout drum pumps, etc. that are used to pump liquids from one place to another. These pumps do not run continuously or even seasonally for long periods, but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, there should be an annual venting limit and an exemption for intermittently operated pumps.

EPA should provide an exemption under the rule for any pump emitting at a rate less than the rate of a continuous low bleed pneumatic controller. Specifically, any pneumatic pump which emits less than 53,000 scf/year (i.e. 6 scf/hour for an entire year) should be exempted. This would provide a reasonable exemption for intermittent use pneumatic pumps which do not have large aggregate emissions, including diaphragm pumps that are operated manually, triggered by a level controller, or operated temporarily or seasonally.

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Alternatively, EPA could use the operating time of a pump with exhaust rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document) that would result in 53,000 scf/year of emissions, which is 96.5 days. This could be rounded down to 90 days of operation, or 2,160 hours. This approach would simplify the exemption, as companies would track the hours of operation instead of calculating the exact exhaust rate.

API proposes the following updates to the applicability text under H.1 of the model rule:

> Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment with an exhaust rate greater than 53,000 scf/year and operates more than 2,160 hours per year and for which a control device owned and operated by the owner and operator of the pump is located on site and not demonstrated to be technically infeasible to control.

15.4.2 The Rule Text Should Exempt Portable Pneumatic Pumps

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. Since these pumps will, by their very nature, result in very low emissions, portable pumps should be exempt from the rule. Such as exemption would be analogous to that provided to portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform) engines relative to the NSPS RICE rules.

API recommends that EPA update the definition of pneumatic pump under the rule to exclude temporary and portable pumps.

EPA should amend the definitions in the draft rule language under Section H to address these temporary and portable sources, i.e. "A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source)." (See revised definition under 15.4.3)

15.4.3 The CTG Text Should Be Clearer On Exclusion Of Lean Glycol Circulation Pumps (Often Referred To As Kimray Pumps) On Dehydration Units (As Intended By The NSPS OOOOa Preamble Language)

EPA's intent is clear in the Preamble (FR 56627) to NSPS Subpart OOOOa that EPA is not proposing to regulate glycol dehydrator pumps under that rule, but the draft CTG text is not as clear on this point.

EPA can improve this by editing the definitions in the CTGs draft rule language. The two definitions below are inconsistent; however, it is noted that neither defined term is used in the CTG text itself. EPA should remove the two definitions below.

> ~~"Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection."~~
>
> ~~"Natural gas-driven chemical/ methanol or diaphragm pump means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas."~~

These definitions should be replaced with the following definition:

> "Natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump means a gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source)."

15.4.4 The Rule Should Allow For Removal Of Control Device – I.E. Pneumatic Pump No Longer Has To Be Controlled If Control No Longer Present

If a control device is no longer needed for the purpose for which it was originally installed, EPA should clarify that any pneumatic pumps that were routed to the device should no longer require control. A control device should not be required to remain in service only for the purpose of controlling one or more pneumatic pumps.

For example, NSPS subpart OOOO allows for removal of control device from a storage vessel if emissions fall below a certain level. Specifically, under the NSPS, EPA has allowed for the removal of control devices once emissions are below 4 TPY (40 CFR 60.5395(d)(2) and 60.5395a(a)(3)). In the preamble to the NSPS OOOO revisions dated April 12, 2013 (Federal Register Vol. 78, No. 71, 22133-22134) EPA also noted that removal of control at 4 TPY will help relieve the control device shortage issue as well as reduce emissions from burning more pilot gas than the waste gas being burned. If a control device is removed, the requirement to route pneumatic pump exhaust to the control device should no longer be applicable.

15.4.5 EPA Must Define "Control Device" In The Context Of Its Use In The Requirements For Pneumatic Pumps

H.2(b)(1) states:

> *Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section.*

Control device is not a defined term and should be specifically defined to clarify EPA's intent which, from review of the complete NSPS OOOOa proposal and TSD, appears to be to utilize combustion control devices and/or VRUs if available. This issue is discussed in Section 10.0, and a definition recommended that will eliminate the issues related to the uncertainty of when the pneumatic pump requirements apply.

However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must made revisions within section H of the CTG model rule to clarify this situation. Specifically, API recommends the following change:

> **H.2(b)(1)** Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section. For the purpose of this section, boilers,

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process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.

15.4.6 The Control Device Must Be Owned and Operated By The Pump Owner and Operator

EPA must be clear that a control device on site must be owned and operated by the same company that owns and operates the pumps. For instance, the dehydration unit located on a production site may be owned and operated by the gathering company, not the producer. If there is a dehydration unit on site with a control device that is owned and operated by the gathering company, the producer has no right to route pump exhaust to the control device and should not be required to route the pump exhaust to the dehydration control device owned and operated by a separate entity.

15.4.7 Heaters Should Not Be Considered As Existing Control Devices (i.e. Pneumatic Pump Exhaust Should Not Be Required To Be Routed To A Heater Simply Because One Is Present)

The language in section E.1 of the model rule describes requirements that each control device must meet and this list includes process heaters. This language could be misinterpreted to mean that any process heater should be considered a control device and thus, its presence would require routing of a pump exhaust to the heater. It is not believed that this was EPA's intent.

EPA should clarify that routing emissions to a process heater should be considered "routing to a process" and the heater should not be considered as a control device. More discussion on this topic is provided in section 10.0. However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must made revisions within section H of the CTG model rule to clarify this situation. The recommended changes are shown above in section 15.4.5.

15.4.8 Non-Affected Facilities (e.g., Pumps Not Requiring Controls Under The CTGs Should Not Have Obligations Under The Rule)

H.3(c) states

> *(c) You own or operate a natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in section H.5(a)(1)(i).*

EPA should remove the requirements requiring certification for pumps located at sites without control devices. Specifically, H.3(c) should be removed from the draft CTGs.

15.4.9 The CTGs Should Not Include An Ongoing Requirement To Review The Status Of The Addition Of A Control Device

Section H.2 of the draft CTGs states:

> *(b)(2) You are not required to install a control device solely for the purposes of complying with the 95 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on site by the compliance date specified by your regulatory authority, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.*

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> *(i) Submit a certification in accordance with H.5(b)(1)(i).*
> *(ii) If you subsequently install a control device, you are no longer required to submit the certification in H.5(b)(1)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with H.5(a)(1)(iii).*

Companies typically do not track serial numbers on pumps, particularly small piston pumps for chemical injection. The pumps are often swapped out and moved around as needed for chemical injection. Typically pumps are purchased in bulk and maintained in a warehouse to install as needed. Trying to keep track of where these pumps are located and a control device is later added will be very difficult.

The applicability of control requirements in the CTGs should be based on an effective date of the CTG and not the construction, modification, or installation of a control device.

15.5 Reporting And Recordkeeping

15.5.1 Remove The Tagging Requirement.

It is unclear what EPA's intent is for requiring tagging of affected natural gas driven pneumatic pumps under H.2(a)(2), H.2(b)(3), and H.3(d). The applicability is clearly stated. The tagging appears to add little value.

API requests that EPA remove the following paragraphs related to tagging:

> ~~H.2(a)(2) Each natural gas-driven pneumatic pump at a natural gas processing plant must be tagged with the date the natural gas-driven pneumatic pump is required to comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that gas-driven pneumatic pump as required in section H.5(a)(1)(i).~~
>
> ~~H.2(b)(3) Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment for which a control device is located on site must be tagged with the date that the pneumatic pump must comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that natural gas-driven pneumatic pump as required in section H.5(a)(1)(ii).~~
>
> ~~H.3(d) You must tag each natural gas-driven pneumatic pump subject to VOC emission requirements according to the requirements of section (a)(2) or (b)(3), as applicable.~~

Building on section 15.4.9, if any tagging is retained, it should be to document that (a) no control device was not onsite as of the CTG effective date and therefore no further action would be needed at any time under the CTG or (b) that a pump is located with a control device on site, but the control has been determined to be technically infeasible.

15.5.2 EPA Should Remove The Recordkeeping Requirements For Control Devices And Closed Vent Systems

As discussed in Section 15.3.1, EPA's costs for controlling pneumatic pumps did not include the cost of the recordkeeping and reporting requirements in the cost estimate. The recordkeeping and

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reporting requirements that EPA has included are burdensome in some cases and expand requirements to non-affected sources.

- H.3(c) requires certification of non-affected sources (Section 15.4.8).
- H.4 requires testing data to be submitted that is not accounted for in the cost analysis, not cost effective when included, and not needed based on the exhaust gas being natural gas, which is the same as the pilot of the combustion device (Section 15.2). EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements.
- H.5(a)(1)(i) – It is not clear what EPA means by records of "the manufacturer specifications". EPA should clearly specify what they want here. It is assumed this refers to the make model of the pump.
- H.5(a)(1)(ii) – Having to continue to track the data of a pump being constructed, reconstructed, or modified at a non-natural gas processing plant location that did not have a control device that later has one installed. Pumps should only be triggered at the time the pump is installed. With the movement and replacement of pumps, keeping track of such information will be extremely difficult. (See Section 15.4.9)

In many instances, these controls have been installed under a state permit (or other regulatory requirement) and have compliance assurance requirements associated with those requirements. It is inappropriate to add new compliance assurance requirements that may conflict to the original requirements the control device was installed to meet. Additionally, the control device may not be able to meet or be retrofitted to meet (i.e. install sample ports) to meet the compliance assurance requirements of the CTG model rule.

API recommends the amendments to the draft rule language as outlined for pumps in these rule comments and those below.

> H.5(b)(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1)(i) through (iv) of this section.
> ~~(i) In the initial annual report, a certification that there is no control device on site, if applicable.~~
> (ii) An identification of each natural gas-driven pneumatic pump, including the identification information specified in section H.2(a)(2) or (b)(3).
> (iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.
> (iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.
> ~~(v) If complying with H.2(b)(1) with a control device tested under section F(d), which meets the criteria in section F(d)(11) and section F(e), records specified in paragraphs (a)(1)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

H.5(a)(1) For each applicable natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (iii) of this section onsite or at the nearest local field office for at least five years.

> (i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the model rule (as specified by the regulatory authority), location and

~~manufacturer specifications~~ make and model for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) ~~Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~

(iv) ~~Except as specified in paragraph (a)(iv)(G) of this section, records for each control device tested under section F(d) which meets the criteria in section F(d)(11) and section F(e) and used to comply with H.2(b)(1) for each pneumatic pump.~~

~~(A) Make, model and serial number of purchased device.~~

~~(B) Date of purchase.~~

~~(C) Copy of purchase order.~~

~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~

~~(E) Inlet gas flow rate.~~

~~(F) Records of continuous compliance requirements in F(e) as specified in paragraphs (a)(1)(iv)(F)(1) through (4) of this section.~~

~~(1) Records that the pilot flame is present at all times of operation.~~

~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~

~~(3) Records of the maintenance and repair log.~~

~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

(G) As an alternative to the requirements of paragraph (a)(1)(i~~v~~)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

16.0 EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In D.2(b) of the CTG model rule, EPA included initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, the model rule includes a fugitive emissions program in Section I that is also based on identifying and repairing leaks. Section I will also apply to covers and closed vent systems, as the definition of "fugitive emissions component" includes "closed vent systems," and "thief hatches or other openings on storage vessels." This results in covers and CVS being subject to both the leak detection and repair requirements in Section I and the leak detection and repair requirements in Section D. This creates a situation which is unnecessarily duplicative and redundant.

Table 16-1 provides a summary of these overlapping requirements.

Table 16-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO

Affected Equipment/Components	D.2		I	
	Inspections	M21	OGI	M21
closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange)	(a)(2) annual visual inspections for defects	(a)(1) Initial, annual, and after repairs/ replacements	Initially, semiannually (could move to quarterly or annual depending on % leakers), and after repair/ replacement	Option for use after repair/ replacement
Closed vent system components other than a joint, seam, or other connection that is permanently or semi-permanently sealed	(b)(3) annual visual inspections for defects	(b)(1) and (2) Initial, annual, and after repairs/ replacements		
Covers	(c) annual visual inspections for defects	n/a		

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the CTG (Table 9-4 and Table 9-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in Section D. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

16.1 Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in the CTG model rule. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

> *"Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from*

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> *regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards."*

API recommends the same definition of closed vent system be added to the CTG model rule with an additional clarification **(bold)** that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

> *Closed-vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of "routed to a process or route to a process" and "fugitive emissions component", as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

16.2 Remove Cover and Closed Vent Systems Components From Definition Of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of "fugitive emissions component" in I.6 needs to be modified.

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, ~~closed vent systems, thief hatches or other openings on a storage vessels,~~ agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 17.2.1.

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16.3 Remove Section D.2

API recommends that all paragraphs of Section D.2 be removed. As shown in Table 16-2 every relevant requirement of D.2 will be addressed by referring to a requirement in Section I, or in the case of the bypass requirements, requirements in D.1. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components.

Table 16-2 Side-by-Side Comparison of CTG Model Rule Section D.2 and Section I Closed Vent System and Cover Requirements

D.2	Section D.2 Requirement	I	Section I Requirement
(a)	CVS Joints, seams and other connectors - Initial M21 and annual visual inspections.	I.2 – I.4	All components – OGI monitoring initial and semi-annual
(b)	Other CVS components - Annual M21 and annual visual inspections		
(c)	Covers - Annual visual inspection		
(d)	Bypass	n/a	Not addressed in section I, but completely addressed in D.1(b)(3)
(e)	M21	not needed	Not needed
(e)(1)-(8)	M21 requirements		
(e)(9)	Repairs - First attempt within 5 days, repair within 15 days.	I.2(f)(1)	Repairs - Repair within 15 days.
(a)(2)	For CVS Joints, seams and other connectors only – monitor using M21 after repair/replacement	I.2(f)(2)	Resurvey (all components) using OGI or M21 within 15 days of repair
(e)(10)	Delay of repair - If technically infeasible without shutdown – do at next shutdown	I.2(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(e)(11)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(e)(12)	Difficult to inspect		
(e)(13)	Records	I.5(a)	Records

The related recommended rule changes throughout the CTG model rule to refer to the analogous sections of Section I rather than Section D.2 are provided in section 16.5.

16.4 The Requirements Do Not Need To Address Covers On Unconcontrolled Storage Vessels And Covers And Closed Vent Systems On Storage Vessels Subject To Legally And Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under the CTG model rule.

Under the draft model rule scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

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Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

16.5 Recommended Changes To NSPS Subpart OOOOa Related To Closed Vent System And Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout the CTG model rule refer to the fugitive monitoring and repair requirements in Section I rather than the cover and closed vent system requirements in Section D. Following are the specific suggested regulatory changes.

I.1 (f) ~~For fugitive emissions components also subject to the repair provisions of sections D.2(e)(9) through (12) and (f)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers~~. You must comply with the requirements of paragraphs (f)(1) and (2) of this section.

A.3(e) You conduct the initial cover and closed vent system inspections required in section ~~D.2~~ I within 180 days after the effective date of this rule as established by your regulatory authority.

A.5(a)
(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and section ~~D.2~~ I.5(a), as applicable.
(6) Records of each closed vent system inspection required under section ~~D.2(a) and (b)~~I.
(7) A record of each cover inspection required under section ~~D.2(c)~~I.
(8) If you are subject to the bypass requirements of section ~~D.2(d)~~D.1(b)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

C.4(a)(4) You conduct the initial cover and closed vent system inspections required in section ~~D.2~~I within 180 days after the effective date specified by your regulatory authority.

C.6(a)(1)

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(iii) Records of each closed vent system inspection required under section ~~D.2(a) and (b)~~I.
(iv) A record of each cover inspection required under section ~~D.2(e)~~I.
(v) If you are subject to the bypass requirements of section ~~D.2(d)~~D.1(b)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.
(vi) If you are subject to the closed vent system no detectable emissions requirements of section ~~D.2(a) and (b)~~I, a record of the monitoring in accordance with section ~~D.2(e).~~ I.5(a).

17.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

17.1 General

The following section addresses comments on EPA's proposed requirements for fugitive component emissions. Comments are organized around the following topics:

- Applicability
- Impacts, Emissions and Costs
- Work Practices and Inspections
- Testing and Monitoring
- Reporting and Recordkeeping.

17.2 Applicability

17.2.1 The Definition Of Fugitives Emissions Component Is Confusing, Which Leads To Duplicative Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 17.2.11).

The definition is also not consistent with the TSD for the rulemaking (Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities, Background Technical Support Document for the Proposed New Source Performance Standards. 40 CFR Part 60, subpart OOOOa, August, 2015). The TSD cites the white paper for the monitoring methods evaluated (Section 5.1 on page 47) and does not include blowdown lines in the description of "potential sources of fugitive emissions", but includes them in the definition of "fugitive emissions component". The white paper clearly states that emissions from blowdown lines/vents are "considered to be vented emissions and not leaks" for the purposes of the paper (page 13).

Furthermore, the types of fugitive emissions components that EPA has proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS Subparts VVa, KKK, and GGGa. Subpart VVa

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defines Equipment as "*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart*" (§60.481a). Under Subpart KKK, EPA defined Equipment as *"each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart"* (§60.631). GGGa defines Equipment as "*each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment*" (§60.591a).

Since these CTGs includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 12.0. Other equipment inappropriately included in this definition includes:

"access doors, ..., thief hatches or other openings on storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters."

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches , which are part of closed vent systems, have complexities of operation and design, as discussed in section 16.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring under Section I of the model rule.

Vents are not fugitive components because they are designed to vent. Compressors are covered in their own section of this rule. Instruments and meters are not defined and some are designed to vent.

The following section in the definition also needs to be deleted as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

> ~~*"Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions."*~~

With the section above in the definition, devices described are not fugitive components if it is not leaking as described. But if it is leaking, it is a fugitive component. Since it cannot be known ahead of time if it is leaking as described, there is no monitoring requirement because it is not a fugitive component until it is determined that it is leaking. These equipment types are not fugitive components, and other directed maintenance programs ensure that this equipment operates as designed.

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API's requested revisions to the definition of Fugitive Emissions Component are provided at the end of this section (see Section 0).

17.2.2 States Should Have The Ability To Utilize Existing LDAR Regulations In Their SIPs Rather Than The EPA Model Rule

EPA did not consider the inconsistencies with state LDAR programs (CO, PA, WY, TX, CA, etc.). This creates duplicative and potentially conflicting requirements with no little environmental benefit. If a state has a leak program in place, the CTG should not impact or disrupt the existing state program. If the EPA has approved a SIP, then the state should be allowed to utilize their existing LDAR regulations rather than following the EPA CTG model rule since the EPA has already approved of the state's LDAR program as part of the SIP. This would eliminate duplicity and redundancy in the state and federal rules.

17.2.3 The 15 BOE Exemption In I.1(a) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 boe/day. This exemption might only be useful in the rare event of a modification to a stripper well.

API believes it more appropriate and would prefer that the CTG be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment.

API would prefer that the rule be based on the equipment located at the site rather than some arbitrary production rate. As indicated in Section 17.2.7, API believes that sites with equipment configurations or component counts less that the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

17.2.4 The 15 BOE Exemption Is Not The Only Exemption To Consider

The 15 BOE/day exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions. However, it would be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should also be another threshold to exempt well sites from leak detection. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions.

Text change recommendation to reflect these comments are provided in Section 0.

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17.2.5 The Definition Of Well Site For Fugitives Is Problematic And A New Definition For "Central Production Site" Is Needed

EPA has expanded the definition of a well site to include tank batteries not at a well site, as follows:

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements. (CTG I-8)

The proposed definition of "well site" includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The practical result of this error is that EPA's proposed definition of "well site" dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. API's recommended definition is provided in Section 0.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements. While the previous paragraphs discussed the issues with the definition of a "well site", a new definition is needed to more accurately account for

centralized sites. API recommends the terms "central production site" and "transmission compressor station" replace the use of the single term "compressor station". A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of this section.

17.2.6 EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of "well site" and "fugitive emission component" could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 17.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

17.2.7 Only Sites With Major Equipment (Such As Separator, Heater, Or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

"For the purposes of this guideline, fugitive emissions recommendations would not apply to well sites that only contain wellheads." (CTG 9.1)

API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome, with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the Technical Support Document (TSD) for NSPS Subpart OOOOa are based on the following assumed equipment and component counts.

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Table 17-1 EPA Model Well Site Equipment and Compressor Counts

	Assumed Equipment Counts		*Assumed Component Counts*	
Gas Well Sites	Wellheads	2	Valves	114
	Separators	2	Connectors	414
	In-line Heaters	1	OELs	14
	Dehydrators	1	PRVs	6
Oil Well Sites	Oil Wellheads	2	Valves	29
	Separators	1	Connectors	104
	Headers	1	OELs	1
	Heater/Treaters	1	PRVs	1

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. It is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

There is a related inconsistency in the CTG text. Section 9.1 (Applicability) says that "for the purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site … and compressor stations in the production segment". However, Section 9.4 (Recommended RACT Level of Control) refers to "RACT for the collection of fugitive emission components at well sites … and gathering and boosting stations".

17.2.8 Based On EPA's Estimates, LDAR Requirements For Oil Well Sites Are Not Cost Effective. Therefore, Oil Wells Should Be Exempt From The CTG LDAR Requirements

Similar to the proposed low producing well site exemption for fugitives, oil well sites should be exempt from the LDAR requirements as discussed earlier (Section 2.2). This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

17.2.9 EPA Should Establish An Applicability Criteria Based On VOC Content Of The Gas Stream.

Unlike other equipment leak regulations, EPA neglected to include any kind of de minimis threshold concentration for VOC. For the CTG, since it is only related to VOC reduction guidance, it should provide a VOC threshold for LDAR as it does for tanks. API believes that the cost effectiveness calculation (see section 2.7 & 8) supports a VOC Threshold of 7% VOC by weight. API does not believe that even the 1% threshold used in the 1983 fugitive monitoring CTG for Natural Gas Processing Plants is supportable.

17.2.10 Components At Enhanced Oil Recovery Fields Must Be Exempted From The Fugitive Emissions Standards In Subpart OOOOa

Background on Enhance Oil Recovery

Crude oil development and production in U.S. oil reservoirs can include up to three distinct phases of recovery: primary, secondary, and tertiary recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. Secondary and tertiary recovery techniques, which are often referred to as Enhanced Oil Recovery, or EOR, extend a field's productive life generally by injecting water, gas, heat, or chemicals to displace oil and drive it to a production wellbore.

Examples of secondary EOR techniques includes water floods, and tertiary EOR techniques includes thermal recovery floods (e.g., steam), and gas injection floods (e.g., CO_2). These EOR oil recovery techniques are used in oil fields to improve oil recovery after reservoir gas has been produced, and reservoir pressure and primary oil production are very low (e.g., no reservoir energy). In addition, the reservoir gas is artificially or mechanically changed with inert gases. Inert gases include nitrogen, hydrogen sulfide (H_2S), and CO_2. These inert gases may be required to be gathered and process through specialty gas plants prior to sale. EOR is commonly found in older oil fields.

Water flooding is used to increase oil production by injecting a substantial amount of water into the oil reservoir rock voidage and increasing reservoir pressure. The injected water displaces the oil and carries the fluids to production wells. Water to oil ratios can be greater than 90%. In some EOR water floods, H_2S and other inert gases are generated in the reservoir. As a result, surface production equipment (i.e., plant) must be designed to handle high volumes of water and 3-phase fluids, and contain the potential "sour" and inert/contaminated gases for personnel safety reasons.

Thermal flooding is used to improve heavy oil recovery by injecting steam into the oil reservoir. Heavy oil has low viscosity, gas to oil ratio (GOR), and typically an API Gravity <18. The steam increases the heavy oil temperature reducing the viscosity allowing the oil to be produced from the well via artificial lift. The thermal surface equipment is designed to manage high volumes of water, heat the water, inject the steam, produce the hot oil, generally 2-phase separation of the fluids, and contain the low volumes of potential "sour" and contaminated gases for personnel safety reasons. Steam floods can generate substantial concentrations of hydrogen sulfide.

Gas injection (CO_2) flooding is used to improve oil recovery by injecting a miscible gas and water into the oil reservoir. The miscible gas, water, and increased reservoir pressure improves oil recovery and fluid sweep. Gas and water are injected into wells and the oil, water, and contaminated inert gas is recovered from production wells. The surface equipment is designed to manage high volumes of water, high pressure gas (e.g., CO_2 as a liquid), injection system, production/gathering system for the multi-phase liquids, high and low pressure separation of the fluids, and greater than 30% inert and potential "sour" gases. Due to the displacement characteristics of CO_2 and Immediately Dangerous to Life or Health (IDLH) for H_2S, the surface equipment is designed for personnel and public safety reasons.

EOR Gas Gathering Systems and Plants are designed to transport and process the volumes and EOR recovered gases that include CO_2, nitrogen (N_2) and H_2S.

EPA Did Not Consider EOR Operations

Oil production fields that utilize EOR have very different gas stream compositions and characteristics from the types of operations that EPA evaluated in the development of the proposed NSPS Subpart OOOOa and the CTGs. These differences have a significant impact on the VOC emissions. EPA's model plants and representative gas compositions used to evaluate the impacts that drove the regulatory decisions are derived from natural gas fields and natural gas processing plants, and these operations do not represent EOR operations. For example, EPA used a single nationwide gas composition to estimate fugitive emissions from all sources.[36] This gas composition includes 3.2% inerts by volume. In the limited time available during the public comment period, API did a very brief survey of member companies and found that the inert content of the gas streams in EOR fields ranged from 14% to over 64% by volume, depending on the type of EOR technique used. Obviously this significant difference in gas composition will have a tremendous impact on the baseline VOC and methane emissions and the emission reductions achieved by the fugitive emission requirements. And without a doubt, the decisions made by EPA regarding the reasonableness of the cost in relation to the VOC and methane emission reductions would not be applicable to EOR fields.

From a careful review of the background information for proposed NSPS Subpart OOOOa after which the CTGs are modeled, it appears that EPA did not consider EOR fields in any manner. A search of the September 18, 2015 preamble, the Background Technical Support Document, and the Regulatory Impact Assessment did not find a single mention of "enhanced oil recovery."

However, while EPA did not consider EOR operations in this rulemaking, clearly they are aware of these operations and the emissions. Subpart W of the GHG reporting program requires the reporting of GHG emissions from EOR operations and defines *enhanced oil recovery as follows:*

> *Enhanced oil recovery* (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Further, subpart W requires reporting of GHG emissions from two specific EOR operations - EOR injection pump blowdown and EOR hydrocarbon liquids dissolved CO_2. Note that in both instances EPA only requires the reporting of CO_2, indicating EPA's expectation that little or no methane would be emitted. Therefore, not only was EPA aware of these EOR operations, EPA had available GHG data from the GHG reporting program that they could have utilized. But they chose to totally ignore this segment in the industry in all technical evaluations.

Conclusions and Recommendation

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.

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[36] Memorandum. Brown, Heather P, EC/R Incorporated to Moore, Bruce, EPA/OAQPS/SPPD. Composition of Natural Gas for use in the Oil and Gas Sector Rulemaking. July 28, 2011.

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- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for Subpart OOOOa and the CTGs.
- These differences will have a significant impact on the VOC baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the CTGs or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in the CTGs. Recommended CTG changes are provided in Section 0.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in the CTGs without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

17.2.11 Produced Water Injection Facilities Should be Exempt from the Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reasons these facilities should not be included in the fugitive monitoring program:

- They contain operations and activities associated with produced water delivery, storage, and injection.
- These facilities are constructed to manage a producing field's water production.
- Natural gas is not typically associated with these facilities.
- There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled.
- Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 17.2.12.

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17.2.12 Recommended Text And Definition Changes Based On Comments In This Section

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day.

(1)The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads.

(2) The fugitive emissions requirements of this section do not apply to any well site or process unit with a GOR less than 300.

(3) The fugitive emissions requirements of this section do not apply to any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system.

(4) The fugitive emissions requirements of this section do not apply to a well site with one or more wellheads that does not include installation of at least one of the following: a separator, heater, or glycol dehydrator.

(6) The fugitive emissions requirements of this section do not apply to a well site that produces oil with either an API gravity less than 18 ˚or a GOR less than 300 scf.

(7) The fugitive emissions requirements of this section do not apply to an EOR .

(8) The fugitive emissions requirements of this section do not apply to a water injection well.

(b) The collection of fugitive emission components at a central production site or a transmission compressor station ~~located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline~~.

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, , including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar~~

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~~as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

Well site means one or more contiguous surface sites~~areas~~ that are constructed for~~directly disturbed during~~ the drilling and subsequent operation of an oil or natural gas well, and any~~, or affected by,~~ production facilities directly associated with any oil well, natural gas well, or injection well. ~~and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements.~~

17.3 Impacts, Emissions, and Costs

17.3.1 EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.

In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- Conducting leak surveys
- Completing repairs, and
- Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- Training of personnel
- Travel time and costs
- Equipment maintenance (e.g. monitoring device calibration)

The following sections expand on each of these topics in more detail and API provides revised costs that are more representative of actual costs anticipated to comply with the proposed rule. Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site. As such, the Well Site Program Weighted Average cost effectiveness values (under a Multi-pollutant Method) would increase significantly beyond the already marginal value of $4,979 per ton of VOC.

When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC. This finding is based solely on corrected costs and does not reflect any changes to the assumed emission reductions, which API believes have been overstated as well.

At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources.

The exception to this is oil wells. As discussed above in section 17.2.8 there is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

17.3.2 EPA Underestimated The Costs Of The Leak Survey And Leak Repairs In The Cost-Effectiveness Evaluation.

In the cost estimation for implementing the LDAR requirements, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site ($600/single well battery37) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site ($600/single well battery) and lower than the value provided for a multiple well site ($1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of $720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

17.3.3 Many Additional Aspects Beyond The Cost Of The Actual Survey Not Considered By EPA Should Be Included In Cost-Effectiveness Evaluation (E.G., Training, Monitoring Device Calibration, Travel Costs, Etc.)

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey, such as program design and set up. EPA's cost analysis also failed to consider costs associated with training, monitoring device calibration, data management, and transportation. These are significant costs and should be part of EPA's assessment of the costs of the proposed requirements.

API surveyed companies conducting voluntary LDAR programs and compared these costs to EPA's model well site costs for annual LDAR. EPA's well pad model plant costs for semi-annual OGI LDAR surveys. Using EPA's cost spreadsheet for OGI well pad costs posted to the docket,[38] API added or updated costs based on company information. API's cost estimate used the same assumptions as EPA's where company data were not available.Key differences in the costs include the following:

- EPA included the cost of a M21 monitoring device ($10,800), but excluded the cost of the data collection system. EPA's separate cost estimate for conducting M21 LDAR includes a cost of $14,500 for a data system in conjunction with the M21 monitoring device. It is not clear why EPA excluded this cost from the OGI LDAR estimate. EPA's estimate for developing monitoring plans does not indicate if it is

[37] Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras.* December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.
[38] CTG_Section_9_OGI_Well_Pad_Model_Plant_Costs_7-7--2015.xlsx

for the corporate level plan, site level plans, or both. EPA's estimate is approximately one-half the cost provided by companies with voluntary programs.

- EPA's estimate of recordkeeping costs does not account for the need to purchase or expand a data collection system to store all the information associated with an ongoing LDAR program. EPA also does not consider the need for a data analyst to manage the information.
- EPA's costs do not consider the purchase of OGI equipment (~$100,000 per unit), annual calibration of each OGI unit, or the training required to operate each unit.
- EPA's costs do not consider travel to and from each site to conduct the semi-annual surveys and for additional travel to repair and resurvey components when the repair cannot be completed immediately following the survey.
- EPA assumed a cost of $2.00 to resurvey repaired components. This cost implies the use of soap bubbles under Section 8.3.3 of M21 to determine if the leak has been repaired. However, as written under §60.5397a (j)(2)(ii)(A), the proposed rule does not specify that soap bubbles can be used to determine if a leak is repaired [§60.5397a (j)(2)(ii)(A) - A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.]. API's cost estimate for resurveying to determine if a leak is repaired is based on determining if the concentration is less than 500 ppm above background.

The following table compares cost information for semi-annual LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs ($1,590 based on API estimates compared to $2,096 from EPA's estimate shown in Table 17-2 Corrected Estimate of Monitoring Costs). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is more than twice EPA's estimate.

Table 17-2 Corrected Estimate of Monitoring Costs

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
One-Time Company Level Costs			
Read rule and instructions	$231.20	$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	$7,200.00	$3,468.00	API members estimate $7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	$1,849.60	$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	$1,271.60	$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	$95,000	Excluded from EPA's analysis	API survey responses ranged from $90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	$225,000.00		API survey responses ranged from $200K-250K

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
FLIR certification Training	$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	$10,800	$10,800	EPA estimate includes cost of M21 monitoring device ($10,800) but excludes the cost of the data collection system ($14,500) that was assumed for M21
First Year Total Hours and Cost per Company	*$343,352*	*$17,620*	Sum of total company costs above
First Year Total Hours and Cost per Well Site	*$15,607*	*$801*	Assumes company owns 22 well sites

Table 17-3 Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	$2,000.00	Not included	API estimates for annual training ranged from $1,000 to $5,000. Conservatively assumed $2,000/yr
Data Analyst	$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	$4,000.00	Not included	API estimates ranged from $3,000 - $5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
Recurring Annual Costs per Company	*$50,000.00*	*Not Included*	Sum of recurring annual costs above
Recurring Annual Costs per Well Site	*$2,272.73*	*Not Included*	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	$63.05	$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	$462.40	$1,200.00	EPA cost from CL Report (outside contractor, well pad, $600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
Repair Cost	$597.48	$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours *$66.24/hr) and 1 fixed offline (1 * 4.0 hours * $66.24/hr)
M21 Resurvey Costs	$115.60	$4.00	EPA's resurvey costs assume cost of $2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	$231.20	$231.20	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
Cost per Well Site (Well site level costs only)	*$1,590*	*$2,096*	Sum of well site level annual costs
Annual Cost per well site with Amortized Capital Cost	***$6,476***	***$2,230***	**Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest**

17.3.4 EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

Section 9.4 of the draft CTG discusses the burden on the operators from the need to hire qualified contractors to perform the monitoring. Most API companies that have implemented voluntary LDAR programs for their upstream operations have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff, and required in many cases, more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand. EPA should provide an initial compliance period of 1 year to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training. In addition, API requests a one-year phase in be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

17.3.5 EPA Did Not Consider Impacts Of Travel To/From Sites By Trained Personnel (Costs And Environmental Impacts)

Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR. A company may have a third party contractor or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average

annual transportation cost per basin is $34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of $20,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

17.3.6 Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed model rule requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is $188,125 with a reccurring average annual cost of $39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at $60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin. These costs were not included in EPA's evaluation of cost effectiveness.

17.3.7 EPA Significantly Underestimated The Costs Of Developing And Maintaining The Corporate And Site-Specific Monitoring Plans

CTG I.2 and I.5 list the reporting, and recordkeeping requirements. Section I.2 describes companies developing both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements.

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plans, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of $3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

API member companies estimate the cost for developing a corporate monitoring plan to be $7,200, and the cost to develop each site-specific monitoring plans to be $120. Annual recurring costs to keep the plans up to date are estimated to range from $1,000 to $3,000.

To count and tag components at a compressor station, costs approximately $10,000. In a study performed by an API member company which compared three basic leak detection methods: Audio, Visual, and Olfactory (AVO), OGI, and M21. M21 was already being conducted, the additional cost of component counts was $15 to $58 per site. However, if done in conjunction with an OGI survey, the cost would be substantially higher. API members estimate a cost of $120 per well site to develop an initial component count (excluding travel costs), and a recurring annual cost of $60/site.

In addition, EPA provided no provision for an area-wide monitoring plan. Section I.2 recommends that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

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- Technique for determining fugitive emissions.
- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.
- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment - Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.
- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may require a company to handle the program differently than in another part of the country where active drilling is taking place.

The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

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The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in (refer to Section 17.3.9).

17.3.8 Fugitive Emissions Program for Gross Emitters

In the preamble for proposed NSPS Subpart OOOO and OOOOa (80 FR 56637), EPA indicated that commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to "gross emitters".

"Notably, we further identified that many studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of VOC emissions from leaks come from a minority of components. Commenters noted that emitters are likely due to random occurrences of low-probability but high-emissions conditions." (CTG 9.4)

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources, where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates.

17.3.9 Recommended Rule Text Revisions Based On Comments In This Section.

(CTG I.2)

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site, central production site, and transmission compressor station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (e) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and control requirements in section D.

(b) You must develop corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and compressor stations in accordance with paragraph (c) of this section, ~~and you must develop a site-specific fugitive emissions monitoring plan specific to each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station that covers the elements of both the corporate-wide and site specific plans.~~

(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, as a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitives are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (e) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii).

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

~~(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.~~

(i~~v~~) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(ii~~v~~) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(iii~~vi~~) Training and experience needed prior to performing surveys.

(iv~~ii~~) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

~~(d) Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(3) of this section, as a minimum.~~

~~(1) Deviations from your corporate-wide plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.~~

Add to the definitions:

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

17.4 Work Practices/Inspections

17.4.1 Requiring An Initial Survey Requirement Within 30 Days Of Becoming Subject To The CTG Is Not Appropriate For A Number Of Reasons.

"(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.
(b) Each compressor station site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.2." (CTG Appendix I.3)

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements, the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 0.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells.. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to the CTG, the central battery must be surveyed

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again a month after the initial survey because of the new well. This time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of the how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 17.4.13).

17.4.2 API Members Find That Recurring LDAR Has A Diminishing Return.

EPA solicited comments on requiring monitoring survey on a quarterly basis. API members find that recurring LDAR has a diminishing return [currently proposed as semiannually]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates , ranging from 0.18% to 0.84% leaks per component for annual LDAR.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)*[39] shows that 5,000 ppm leaks were detected

[39] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at

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with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."

17.4.3 API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components.

EPA solicited comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

> *"We recommend that the monitoring frequency be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station."* (CTG 9.5.1)

API does not support the proposed metrics of one percent and three percent of components, respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components.

To count and tag components at a compressor station, costs ~$10K and requires continual ever-greening. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was $15 to $58 per site. However, if done in conjunction with an OGI method, the cost would be substantially higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of $120 per well site to count

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http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

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components initially, with a recurring cost of $60 per well site to validate and update the counts annually.

17.4.4 Having The Same Frequency Of Monitoring As EPA's NSPS OOOOa Will Be Far Too Burdensome With The Large Number Of Existing Sites Which Are Almost All Unmanned, Dispersed Locations.

The draft August 2015 CTG (EPA-453/P-15-001) proposes semiannual fugitives monitoring of well sites greater than 15 boe/day and gathering/booster stations as RACT (page 9-31). The cost data presented in Table 9-11 shows a cost of $8,069/ton of VOC reduction for annual OGI inspections, while Table 9-12 shows a cost of $9,124/ton of VOC reduction for semi-annual OGI inspections. Despite a cost difference of $1,055/ton of VOC reduction or only 12.3% difference, EPA proposes semiannual OGI inspections as RACT. The small cost difference (based on EPA's analysis) between annual and semi-annual inspections does not justify the semi-annual inspections.

Also, the cost data on page 9-19 of the August 2015 CTG shows an OGI contractor cost estimate of $600 for a well site and $2,300 for a gathering/booster station, and repair costs of $299 for well sites and $3,436 for gathering/booster stations assuming 1.18% of the components leak and 75% are repaired online and 25% are repaired offline. EPA estimated the cost for resurveying components after offline repair based on $2.00 per component resurveyed and the assumption that a company purchases M21 instrumentation for $10,800 and is able to perform the resurveying without needing contractors. EPA assumed annual reports would take one person a total of 4 hours to complete at a cost of $231.

For comparison purposes, the costs from the Colorado Regulation 7 survey data were the following: OGI survey by contractor - $200-400 per well site, $1,321 for gathering/booster stations; excludes equipment rental, which is approximately $250 per site; Repair costs - $200 for well sites; Annual reports - $4,370 average annual report for a company's basin (note that Regulation 7 reports are required on a basin basis).

EPA assumes companies will use a third party for monitoring at $600 per site and does not include estimated costs for a company to buy and maintain a camera of their own (higher capital cost) or supervisory costs. In the report "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" (March 2014, Prepared for Environmental Defense Fund by ICF International) a more representative cost analysis includes the camera purchase costs as well as transportation and recordkeeping, resulting in an annual cost of $191,000 (compared to $4,031 in the EPA OOOOa TSD, assuming quarterly OGI inspections as presented in Table 5-19). This analysis was updated in 2014 in which the annual cost (including cost of repairs inadvertently omitted from the previous analysis) was $193,000.

17.4.5 Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Component Counts For Each Well Site In Order To Properly Document The Percentage Of Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage.

"We recommend a monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station be conducted at least semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend that the monitoring frequency be increased to quarterly in the

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event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station." (CTG 9.5.1)

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment, which are combined with EPA assumptions on component counts per equipment.

See Section 17.3.8 regarding API's preference for annual monitoring.

17.4.6 API Opposes Performance-Based Frequency

EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based approach. Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in the comment above, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. API advocates a fixed annual frequency, regardless of the percent of leaking components.

17.4.7 API Suggests 30 Days An Appropriate Amount Of Time For Repair Of Sources Of Fugitive Emissions At Well Sites

EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team, when authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However a few leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Recent data from Colorado's Regulation 7 indicate that about 5% of

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identified leaks required a delay of repair.[40] It is more reasonable to allow 30 days to do the repairs.

Proposed text revisions are provided in Section 17.4.13.

17.4.8 The current proposal does not allow for multiple attempts to repair identified leaks

In the proposed model rule, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak. Proposed text revisions are provided in Section 17.4.13.

17.4.9 Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Regulation 7 indicate that about 5% of identified leaks required a delay of repair.[41] Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate

[40] Colorado Air Quality Control Commission, Public meeting on October 15, 2015.
[41] Colorado Air Quality Control Commission, Public Meeting on October 15, 2015.

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shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months and OOOOa should be less stringent that what is required under NSPS Subpart VVa. Subpart VVa under §60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair:

§60.482-9a *(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.*

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

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(f) When delay of repair is allowed for a leaking p ump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition."

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Proposed text revisions are provided in Section 17.4.13.

17.4.10 Thresholds for M21 Leak Definition and Repair.

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). EPA also solicits comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA–HQ–OAR–2010–0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found-leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak threshold should be set at 10,000 ppm.

Proposed text revisions are provided in Section 17.4.13.

17.4.11 API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

"We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites and compressor stations." (CTG 9.4)

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EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles.

17.4.12 Monitoring Each Fugitive Component for Emissions

CTG I.2(e) – EPA is requiring that "*Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.*" Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. . Here is an example of what the sites look like:

Figure 17-1 Picture of Equipment Building

API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components.

Proposed text revisions are provided in Section 17.4.13.

17.4.13 Recommended Text Revisions Related To Work Practices/Inspections:

> I.2(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components for fugitive emissions.
>
> I.2(f)(1) Each identified source is required to monitor fugitive emission components as specified in section I.3 and I.4. Identified fugitive emissions shall be repaired or replaced as soon as practicable, ~~but~~ no later than ~~15~~30 calendar days after detection of the fugitive emissions. Where delays in acquiring replacement parts prevent completion of repairs

within 30 days, repairs must be completed within 30 days of acquiring parts. If the repair or replacement is technically infeasible or unsafe, or shutdown emissions are larger than what would be reduced ~~to repair during operation of the unit~~, ~~to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than ~~15~~30 days after completion of the repair or replacement, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using M21 or optical gas imaging no later than ~~15~~30 days of finding such fugitive emissions.

(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

I.3(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within ~~30~~180 days of being subject to VOC emission control requirements of section I.
(b) Each compressor station site or central production site with a collection of fugitive emissions components must conduct an initial monitoring survey within ~~30~~180 days of being subject to VOC emission control requirements of section I.2.

(a) A monitoring survey of each collection of fugitive emissions components at a well site, a central production site, and a compressor station site subject to VOC emission control requirements under section I shall be conducted at least ~~semi~~annually after the initial survey. Consecutive ~~semi~~annual monitoring surveys shall be conducted at least nine ~~four~~ months apart.
~~(b) The monitoring frequency specified in paragraph (a) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than three percent of the fugitive emissions components at a well site or at greater than three percent of the fugitive emission components at a compressor station subject to VOC emission control requirements under section I.~~
~~(c) The monitoring frequency specified in paragraph (a) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect no fugitive emissions at less than one percent of the fugitive emissions components at the well site, or less than one percent of the fugitive emissions components at a compressor station subject to VOC emission control requirements under section I. The monitoring frequency shall return to semiannual if a annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and shall return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station.~~

17.5 Testing And Monitoring

17.5.1 EPA Should Provide Flexibility And Allowance For Technology Development.

Ongoing Research and Development Activities

The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of M21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E)

As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totalling some $35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify - major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired.

ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera ($90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to $3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as $1,000 per site.

EDF Methane "Detectors Challenge" (MDC)

In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and natural gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot

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purchases and testing at oil and natural gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and natural gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a "smart" alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The "MDC program refers to cost as a critically important factor and EDF and its partners sought out technologies that could reasonably be expected to be sold for roughly $1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.

The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1." Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2" which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations

An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye." EPA's Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)[42] provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should allow any new technology to be used that is equivalent to OGI or M21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA's current definition of OGI (i.e. "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye."). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

17.5.2 The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

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[42] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

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A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).
- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H_2S concentrations where AVO is more effective than M21. Sites with high levels H_2S should be allowed to use AVO or H_2S monitoring systems to identify leaks at well pads.

17.5.3 Characterizing Performance Using Laser Technology

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since the CTGs do not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

17.5.4 A Streamlined Approval Process Is Needed For Alternative Technologies As These Technologies Become More Prevalent.

EPA should build into its final rule an "on-ramp" that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined "fast-track" process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved

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for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level "equivalency" should not be required as EPA has required for using OGI versus M21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow "equivalence test for approving alternative methods. Moreover, the stringency of the process and "equivalency" testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in §60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7[43] provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or M21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

17.5.5 Comment On Whether To Allow EPA M21 As An Alternative To OGI For Monitoring, Including The Appropriate EPA M21 Level Repair Threshold

The draft CTG implies that the initial leak surveys must be taken using an OGI. We recommend revising the requirements to specifically state that OGI, M21, or an equivalent method may be used for both the initial survey and repair leak surveys.

In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves M21 for repair confirmation and emissions quantification is not required. According to Section 8.3.3 of M21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under M21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap

[43] https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf

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bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

17.6 Reporting And Recordkeeping

17.6.1 The CTG Should Not Require A Separate Report For Each Well Site.

CTG I.5 (b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

API interprets "each collection of fugitive emissions components" to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations submit the combined reports in one annual report.

17.6.2 The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value.

CTG I.5(a)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed. Under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the CTG it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. Photos of the well site or compressor are not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

A photo of a survey being performed does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator's certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey. In addition, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate.

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In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally un-manned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey.

Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. API requests that EPA remove the requirement to take a photograph.

17.6.3 API Strongly Opposes Sending Digital Photographs And Logs To The Permitting Agencies.

EPA solicited comments on whether these [digital photographs and logs] records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens API strongly opposes sending digital photographs and logs to the permitting agencies. EPA's cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there is a real security risk putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with little to no security.

17.6.4 EPA Needs To Greatly Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

> *"XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.*
> *XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;*
> *XVII.F.8.b. The date and site information for each inspection;*
> *XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;*
> *XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;*
> *XVII.F.8.e. The date the leak was repaired;*
> *XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;*

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> *XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and*
> *XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s)."*

API requests that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

> *"XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:*
> *XVII.F.9.a. The number of facilities inspected;*
> *XVII.F.9.b. The total number of inspections;*
> *XVII.F.9.c. The total number of leaks identified, broken out by component type;*
> *XVII.F.9.d. The total number of leaks repaired;*
> *XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and"*

17.6.5 Proposed Text Revisions Associated With Reporting and Recordkeeping Requirements.

I.5(a) Records for each monitoring survey shall be maintained as specified in paragraphs (a)(1) through (6) and must contain, at a minimum, the information specified in paragraphs (a)(1) through (a)(6). Records are required to be maintained onsite or at the nearest local field office for at least five years.

(1) Date of the survey.
(2) Location of the survey
(3) A list of leaking components
(4) The date of the first attempt to repair and additional attempts to repair
(5) The date the leak was repaired
(6) The delay of repair list including the basis for placing leaks on the list
(7)The date the leak was remonitored to verify the effectiveness of the repair

~~(2) Beginning and end time of the survey.~~

~~(3) Name of operator(s) performing survey. You must note the training and experience of the operator.~~

~~(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(5) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(6) Documentation of each source of fugitive emissions (e.g. fugitive emissions component), including the information specified in paragraphs (a)(6)(i) through (iv) of this section.~~

~~(i) Location.~~

~~(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photo graph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(iii) The date of the successful repair of the fugitive emission component.~~

~~(iv) The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

(b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a central production site or transmission compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a central production site or transmission compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

Attachment A

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Prepared by: David A. Simpson, P.E.
MuleShoe Engineering

Prepared: February 16, 2010

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February 16, 2010

Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the "most accurate" volumes if the gas was metered as a "fuel" stream and a "control" stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to "provide the rigor required for either cap-and-trade or offset programs". The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer's numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The "Per Company" column below assumes 2,000 wells per company, "Total WCI" column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under "Cost of Implementation" below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well ($k)	Per Company ($million)	Total WCI ($million)
RTU Replacement	$3.5	$7	$350
Host/Database		$15	$750
Site Modifications	$30.0	$60	$3.000
Total Capital	$33.5	$82	$4,100
Annual Operating Costs	$1.5	$3	$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

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II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate "accuracy" in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different "emissions factor" on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

   The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

   Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

   I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as "on demand" in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

   The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators

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take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 "turndown ratio". Turndown ratio is a measure of ability of a measurement device to provide similar "accuracy" over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from "off " to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer's estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since "rich" liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

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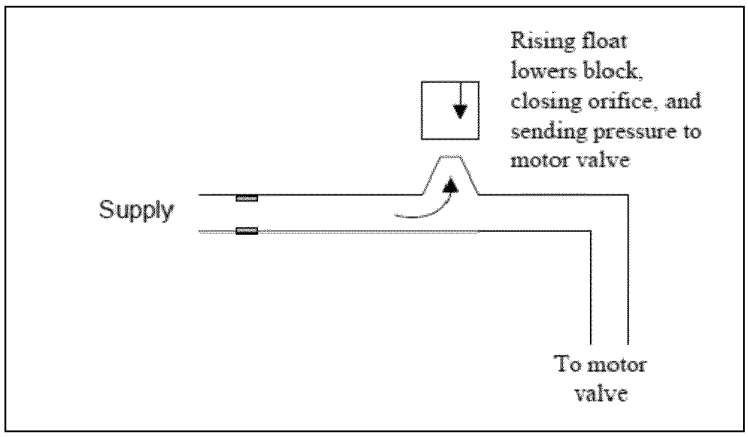
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

4. *Pneumatic devices*

I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either "Throttling" or "Snap Acting". Bleed characteristic is either "continuous bleed" or "no bleed" An example of a Continuous Bleed, Throttling controller is shown below



In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled

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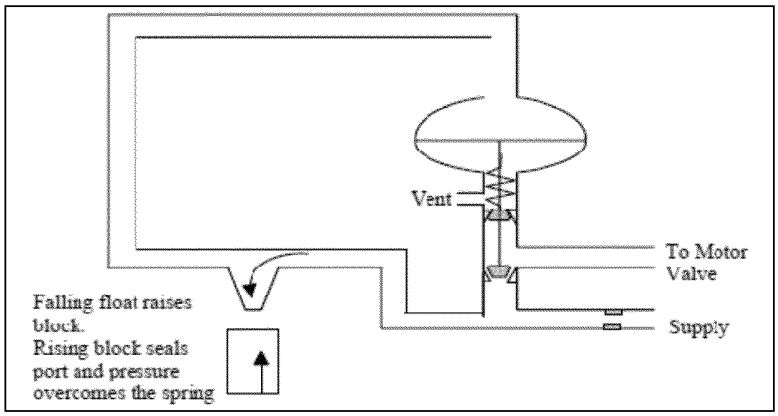
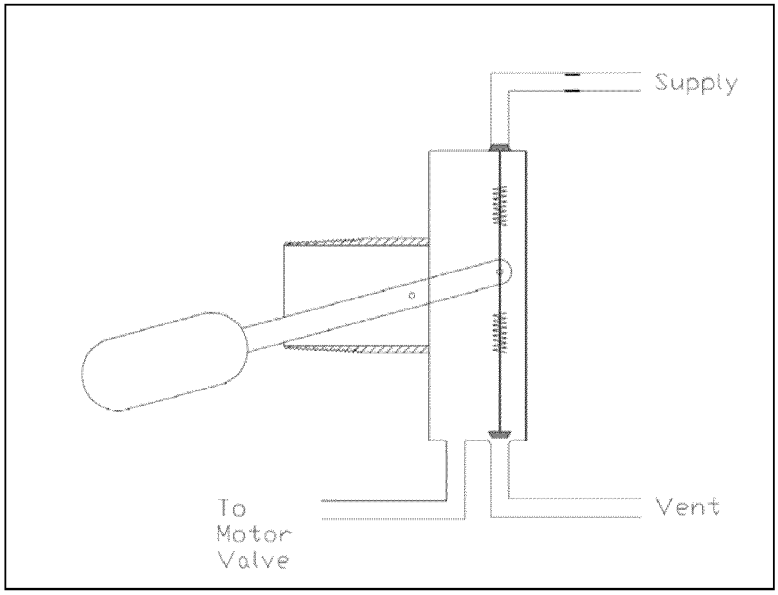
devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A "No Bleed" controller would look something like:



This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the

vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it "snaps" open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas us used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing "bleeding" of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can't be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a "jerky" action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft^3) and the diaphragm dome is 0.04 ft^3 (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft^3. At 35 psig and 60□F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:

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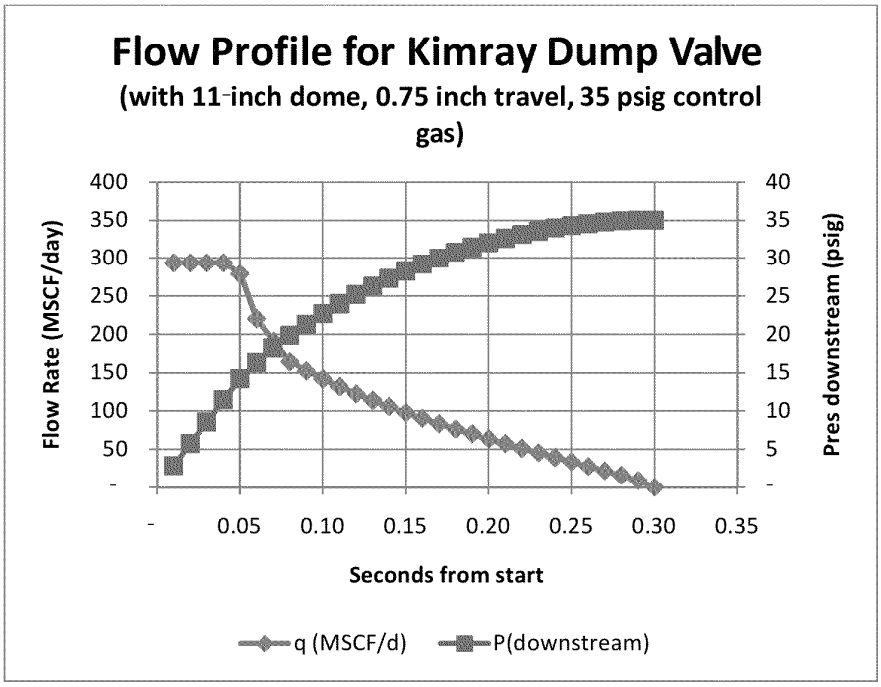

Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about "meter accuracy" above I always said "accuracy". "Accuracy" is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of "accuracy" is encompassed in the terms "repeatability" and "uncertainty" which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

"Repeatability" is a measure of a device's ability to report the same output for a given set of inputs. Many things can impact a device's repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable

repeatability occurs when the standard deviation of the sample data is within ±0.05% of the mean value.

"Uncertainty" is the "dead band" of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device's calibrated span. For example, a digital pressure transducer may have a stated uncertainty of ±0.5% which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices' uncertainty is less than ±2.0% (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is "latency". Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are "inferential" technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli's development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

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1. *Gas Analysis*

   Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

   For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed ±25%.

   These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

   The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

   Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

   This device has potential, but the smallest meter (1/2" ID) would register zero during pilot flow and would have a dP less than 7 inH_2O (0.25 psi)

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while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

   The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

   Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

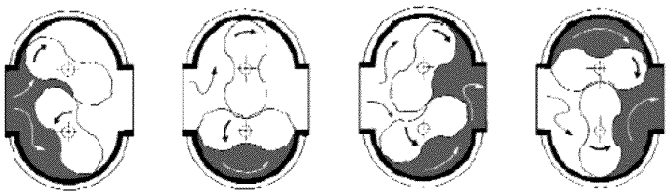
   The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

   The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

   The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to "measuring" gas volumes instead of "inferring" a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

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8. *Diaphragm Meters*

   The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

   The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. "Household quality" meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H_2S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). "Industrial quality" meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or "yellow metal" is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

   The volume of gas discussed in this application kept leading me to devices like "Thermal Dispersion Meters" (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

    In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

    a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.

    b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

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The theoretical values for burners could be improved by putting a "valve open" clock on the supply line, which (in conjunction with manufacturer's data and Engineering analysis) would result in a better volume than attempting to meter the gas.

c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Corriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.

d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can't be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a "standard" wellsite where fuel-gas measurement equipment can be "relatively easily" installed. This is patently false. The implication is that every site looks something like:

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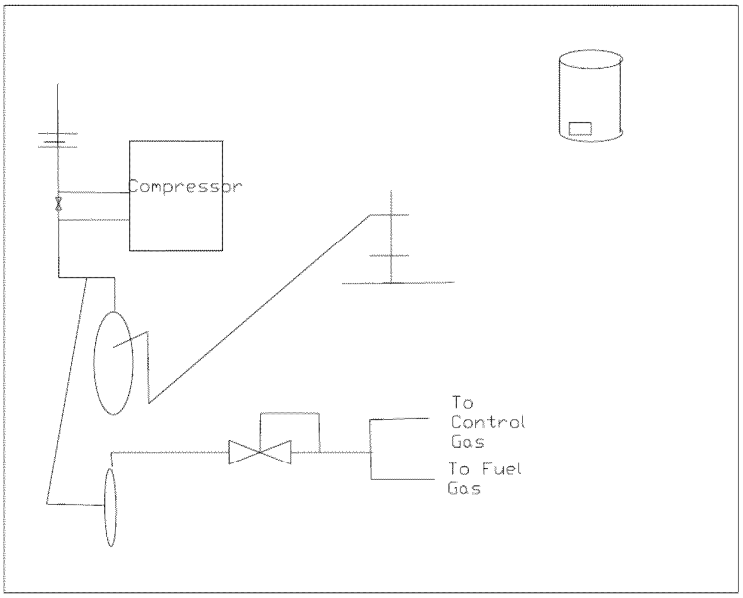
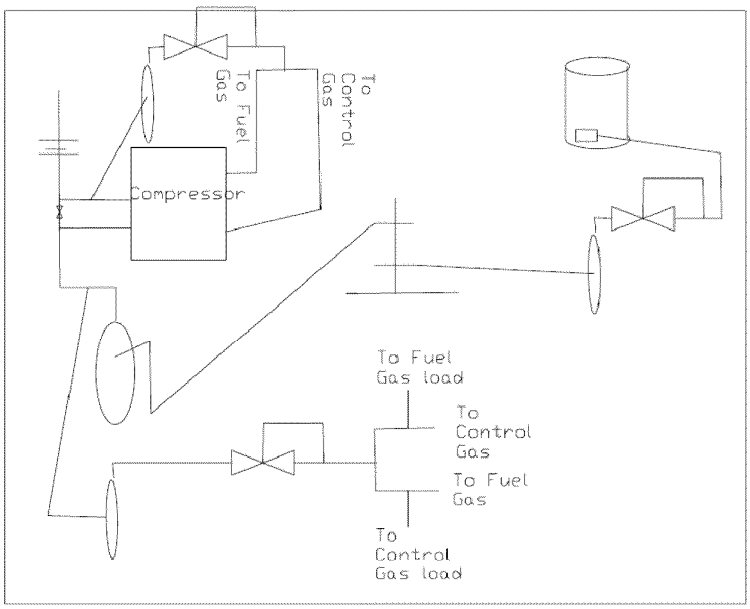


This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since

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compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a "typical" wellsite, "typical" automation system, or "typical" host/database modification because there is no such thing. There are companies within the WCI area of operation that don't have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I've worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at http://www.capp.ca/GetDoc.aspx?DocID=146286 for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I'll use 100,000 wells.

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A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of $4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately $3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data poling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost $15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend $750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At $1,200/day that is $12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be $30,000/well—100,000 wells would cost $3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a $5/MMBTU sales price the cost of this lost production is $600 million across 100,000 wells.

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D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is $150,000/year which works out to about $750/meter/year or $1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.

February 16, 2010

To: Pruitt, Scott[Pruitt.Scott@epa.gov]
Cc: Jackson, Ryan[jackson.ryan@epa.gov]; Dravis, Samantha[dravis.samantha@epa.gov]; Leslie.Couvillion@BakerBotts.com[Leslie.Couvillion@BakerBotts.com]
From: megan.berge@bakerbotts.com
Sent: Wed 4/19/2017 7:05:16 PM
Subject: EPA–HQ–OAR–2015–0500; Re-Submission of Petition for Reconsideration of the Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS
OK Cogen CSAPR Update Petition for Reconsideration.PDF
APPENDIX A (OK COGEN) - ALLOCATION CALCULATIONS (Working Courtesy Copy).pdf
APPENDIX B (OK COGEN) - EIA DATA DOWNLOAD 2008-2014 (Working Courtesy Copy).pdf

Dear Administrator Pruitt,

Attached please find a petition by Oklahoma Cogeneration, LLC ("OK Cogen") for reconsideration of the final rule entitled "*Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*," Docket No. EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74,504 (Oct. 26, 2016). The attached petition and appendices were submitted to the prior administration on December 22, 2016, within the time period specified in the Clean Air Act.

Given that the 2017 ozone season is set to begin in May, OK Cogen must begin making decisions about purchasing allowances and taking other actions to comply with the regulation. OK Cogen's requested relief in its petition includes re-allocation of allowances to its Oklahoma Cogeneration LLC Unit CC01. OK Cogen would appreciate any clarity you can provide on EPA's intention to act on the petition.

A hard copy of the petition, along with a CD-Rom containing both PDF and Excel versions of the appendices, also is being sent to EPA via first-class USPS mail.

Respectfully,

Megan

Megan Heuberger Berge
Partner
BAKER BOTTS L.L.P.
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BAKER BOTTS

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Oklahoma Cogeneration, LLC
"The Cleaner Energy Choice Since 1989"

December 22, 2016

VIA ELECTRONIC SUBMISSION AND HAND DELIVERY

Office of the Administrator (Mail Code 1101A)
US Environmental Protection Agency
1200 Pennsylvania Avenue NW, Room WJCN 3000
Washington DC 20460

RE: Request for Reconsideration of EPA's "Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS" (EPA Docket No. EPA-HQ-OAR-2015-0500)

Dear Administrator:

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, Oklahoma Cogeneration, LLC ("OK Cogen") respectfully petitions the U.S. Environmental Protection Agency ("EPA" or "Agency") for reconsideration of the final rule entitled *"Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,"* 81 Fed. Reg. 74,504 (Oct. 26, 2016) ("CSAPR Update Rule" or "Final Rule"). Specifically, OK Cogen requests that EPA recalculate unit-level allocations of seasonal nitrous oxide ("NOx") allowances for 2017 and beyond for OK Cogen's Oklahoma Cogeneration LLC Unit CC01 (Boiler ID CC01; ORIS ID 50558; CAMD Unit ID 90991) using data-substitution called for by the Final Rule. EPA's current calculations rely on a single (highly unrepresentative) year of data for Unit CC01, resulting in a significant allowance shortfall. This outcome contradicts EPA's own stated methodology and policy goals.

OK Cogen is a small (two full-time employees, with 18 operational personnel) electric service company located in Oklahoma City, Oklahoma. The company is committed to environmental compliance and efficient NOx emissions controls. OK Cogen operates a single, independent 120 MW (nominal) natural gas-fired combined-cycle and topping-cycle cogeneration power plant ("Unit CC01").[1] The facility consists of a natural gas-fired combustion turbine ("gas turbine"), a supplementary fired Heat Recovery Steam Generator that can receive additional energy from a natural gas-fired duct burner ("duct burner"), and a single automated extraction condensing steam turbine generator ("steam turbine").[2] As a direct means of controlling NOx

[1] Formerly known as the PowerSmith Cogeneration Project.

[2] The unit's normal load (from gas and steam turbine electricity production) is 107 MW. The duct burner is used to make maximum load, and is used infrequently (only when called upon for dispatch by the Southwest Power Pool). In 2016, the duct burner was called upon twice, for a total of 15 hours of run time.

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emissions, this system injects steam into the gas turbine combustion chamber. The combined exhaust gases exit through a common main stack. The electricity is sold under a long term Power Purchase Agreement to a local electric utility company that serves customers in Oklahoma and Western Arkansas. Unit CC01 has been in operation since 1989. It was the first natural gas-fired combined-cycle cogeneration plant built and operated in Oklahoma.

BACKGROUND

CSAPR addresses the "good neighbor" provision of the Clean Air Act, which prohibits sources within each state "from emitting any air pollutant in an amount which will . . . contribute significantly" to any other state's nonattainment, or interference with maintenance of, any National Ambient Air Quality Standard ("NAAQS"). 42 U.S.C. § 7410(a)(2)(D)(i)(I). EPA defines "significant contribution" by reference to (1) a state's "linkage" to downwind receptors (i.e., emissions of approximately 1 percent of compliant ambient levels) and (2) the ability of the state to achieve emission reductions at the relevant cost threshold.[3] CSAPR achieves emissions reductions through annual and ozone season emissions trading programs.

EPA finalized CSAPR in 2011 to address three NAAQS, including the 1997 ozone NAAQS. 76 Fed. Reg. 48,208 (Aug. 8, 2011) ("Original CSAPR Rule" or "CSAPR"). In December 2011, EPA finalized a supplemental CSAPR rule that added several states, including Oklahoma, to the ozone season NOx program. 76 Fed. Reg. 80,760 (Dec. 27, 2011) ("Supplemental CSAPR Rule"). Various groups challenged CSAPR, resulting in a stay of the rule. *See EME Homer City Generation, L.P. v. EPA*, No. 11-1302 (D.C. Cir. Dec. 30, 2011). CSAPR and Supplemental CSAPR Rule requirements and deadlines were effectively tolled pending resolution of the litigation. *See* 79 Fed. Reg. 71,663 (Dec. 3, 2014). In April 2014, the U.S. Supreme Court generally upheld the rule. *See EPA v. EME Homer City Generation LP*, 134 S. Ct. 1584 (2014). The stay was lifted in October 2014. *See EME Homer City*, No. 11-1302 (Oct. 23, 2014). Phase 1 of the CSAPR ozone season program began in May 2015.

EPA published the CSAPR Update Rule in October 2016 to address good neighbor provisions with respect to the 2008 ozone NAAQS. The Agency had published a proposed rule about 10 months earlier. *See* 80 Fed. Reg. 75,706 (Dec. 3, 2015) ("Proposed CSAPR Update Rule" or "Proposed Rule"). In the Final Rule, EPA found that 22 eastern states, including Oklahoma, had failed to submit a state implementation plan to meet their good neighbor obligations. For these 22 states, EPA issued federal implementation plans that generally update existing CSAPR NOx ozone season emission budgets, and that implement these budgets through modifications to the existing CSAPR NOx ozone season allowance trading program. The Final Rule addresses only emission reductions from electric generating units ("EGUs"). Implementation will start in the 2017 ozone season (May - September 2017).

EPA made several significant changes between the Proposed and Final CSAPR Update Rules. Most notably for OK Cogen:

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[3] EPA uses the Integrated Planning Model v.5.15 ("IPM") to predict how many emissions reductions are available at the relevant cost thresholds. IPM is a dynamic, linear programming model used to project power sector behavior under current and future conditions. IPM's primary objective is to provide estimates of least-cost capacity expansions, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. *See* https://www.icf.com/solutions-and-apps/ipm.

(1) **In calculating allocations for Oklahoma units in the Final Rule, EPA did not use data-substitution.** Both the Proposed and Final Rules call for EPA to use up to *five* years of historic heat input data and up to *eight* years of historic NOx emissions data.[4] To accomplish this, both rules also call for EPA to use a data-substitution method (so that if data is not available from EPA's preferred data source for a given year, EPA can pull equivalent data from an alternative source).[5] EPA followed this method in the Proposed Rule.[6] But in the Final Rule, EPA switched to using a *single year of historic baseline data without any data-substitution* for Unit CC01. *See* EPA, Final Rule, *Unit-Level Allocations and Underlying Data for the CSAPR Update for the 2008 Ozone NAAQS* ("Final Allocation Spreadsheet TSD"). Unit CC01's allowance allocation ***dropped more than 70 percent*** from the Proposed Rule to the Final Rule, from 40 allowances to 12 allowances.

(2) **In calculating Oklahoma's budget in the Final Rule, EPA used a revised formula with new inputs.** Both the Proposed and Final Rules call for EPA to set state budgets as the minimum of either (1) historic emissions[7] or (2) IPM-predicted 2017 emissions. In the Final Rule, EPA introduced new variables to the formula for calculating IPM-predicted 2017 emissions, including (1) a NOx emission rate "delta" (equal to the difference between an IPM 2017 Base Case and IPM 2017 Policy Case emission rate); and (2) an "adjusted" historic emission rate, based on a newly-developed adjusted historic dataset. With these new variables, EPA added several steps to the calculation and increased its complexity. *See* 81 Fed. Reg. at 74,547-48. Due in large part to these changes, Oklahoma's budget ***dropped about 28 percent*** from the Proposed Rule to the Final Rule, from 16,215 tons to 11,641 tons, more than any other state.[8] Oklahoma's reduced state budget contributed to Unit CC01's reduced allowance allocation.

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[4] To calculate allocations, EPA first "uses the average of the three highest years of heat input data out of a consecutive five-year period to establish the heat input baseline for each unit," and calculates initial heat input-based allowance allocations based on each unit's percentage share of the state's total ozone season heat input. 81 Fed. Reg. at 74,564. Next, EPA "constrains the unit-level allocations so as not to exceed the maximum historical baseline emissions, calculated as the highest year of emissions out of a consecutive eight-year period." *Id.* This methodology "bases a unit's allocation on the unit's historical heat input but limits any unit's allocation to its historical maximum emissions." EPA, *Allowance Allocation Final Rule TSD* at 6 (Aug. 2016) ("Allocation TSD"), available at https://www3.epa.gov/airmarkets/CSAPRU/CSAPR%20Allowance%20Allocations%20Final%20Rule%20TSD.PDF.

[5] The two data sources EPA says it will look to are: (1) EPA's Clean Air Markets Division ("CAMD"), for years for which it is available; and (2) the U.S. Energy Information Administration ("EIA"), for years for which CAMD data is unavailable.

[6] With some caveats: EPA did not include 2014 EIA data because it was unavailable at the time the Proposed Rule was published. Thus, for units without 2014 CAMD data, EPA did not "backfill" or substitute any EIA data. Additionally, EPA did not include data for years for which a unit was not yet operating (e.g., if a unit that began operating in 2012, EPA used available 2012-2014 heat input and NOx emissions data). *See* EPA, Proposed Rule, *Unit Level Allocations and Underlying Data for the CSAPR for the 2008 Ozone NAAQS* ("Proposed Allocation Spreadsheet TSD"). Excel file available at https://www.epa.gov/airmarkets/proposed-cross-state-air-pollution-update-rule. Further, as discussed below, EPA inappropriately relied on annual, not monthly, EIA data and made arbitrary downward adjustments to reported EIA data for cogeneration and combined-cycle units. EPA should use monthly, reported (i.e., unadjusted) EIA data in the revised Final Rule allocations.

[7] Based on a baseline year of 2014 in the Proposed Rule and 2015 in the Final Rule.

[8] Under the Proposed Rule formula, Oklahoma's IPM-predicted 2017 emissions were *higher* than historic emissions. Thus, Oklahoma's budget was set equal to historic (2014) emissions. Under the revised Final Rule formula, Oklahoma's IPM-predicted 2017 emissions were *lower* than historic (2015) emissions. Thus, Oklahoma's budget was set equal to these lower IPM-predicted emissions. This change was not driven solely by the switch from a 2014 to 2015 historic baseline. The primary driver appears to be the new IPM-derived emission rate "delta." Oklahoma's IPM 2017 Base Case emission rate is unrealistically and arbitrarily high—

REQUEST FOR RECONSIDERATION

I. Requested Technical Correction

A. EPA Should Correct Errors In OK Cogen's Allowance Allocations

EPA's unit-level allowance allocation calculations in the Final Rule are arbitrary and capricious as applied to OK Cogen's Unit CC01. EPA's failure to perform EIA data-substitution—and use of a single historic baseline year for some units—goes against the Final Rule's own prescribed methodology. It also puts units on unequal footing: some units, like Unit CC01, received allocations based on one year of operation, while other units received allocations based on multiple years of operation. This effectively penalizes units, like Unit CC01, that were not required to report to CAMD in prior years. OK Cogen is especially disadvantaged because Unit CC01's single year of available CAMD data (2015) is highly unrepresentative of the unit's historic operations.

EPA must recalculate OK Cogen's allocations for Unit CC01 to avoid this unfair and arbitrary outcome. Specifically, EPA must use (1) five years of reported heat input data (2011-2015) and eight years of reported NOx emissions data (2008-2015); and (2) EIA data-substitution, where CAMD data is unavailable. Therefore, OK Cogen's allocations for Unit CC01 should be based on 2011-2014 EIA and 2015 CAMD heat input data and 2008-2014 EIA and 2015 CAMD NOx emissions data. EPA should use monthly (not annual), reported (not adjusted) data. Corrected calculations,[9] summarized in Table 1, show that OK Cogen likely is entitled to 62 total allowances compared to 12 allowances under the current calculation: ***an increase of 50 allowances, or more than 500%***. *See* Appendix A (CD-Rom Enclosure) for detailed calculations.[10]

Table 1. Comparing OK Cogen's Unit CC01's Average Heat Input, NOx Emissions Maximum Historic Baseline, and Final Allowance Allocations Under the Final Rule and a Corrected Rule.

	Final Rule (No EIA Data)	Corrected Rule (Monthly Reported EIA Data)	Difference
3-Year Average Heat Input	**284,731 MMBtu** (based on 2015)	**1,478,244 MMBtu** (based on 2011-2013)	**1,193,513 MMBtu**
NOx Emissions Maximum Historic Baseline	**43 tons** (based on 2015)	**163 tons** (based 2011)	**120 tons**
Final Allocation	**12 tons**	**62 tons**	**50 tons**

significantly higher than Oklahoma's historic actual or adjusted 2015 emission rates. As a result, Oklahoma's NOx emission rate "delta" also is arbitrarily high. This means the Final Rule formula over-estimates how many emissions reductions are available in the state. This error carries through the entire calculation, resulting in final IPM-predicted 2017 emissions that are unrealistically low. These arbitrarily low model-predicted rates became the basis for Oklahoma's final budget. *Compare* EPA, Proposed Rule, *Appendix E- Detailed Budget Calculations*, Excel file available at https://www.epa.gov/airmarkets/proposed-cross-state-air-pollution-update-rule-ozone-transport-policy-analysis-tsd *with* EPA, Final Rule, *Appendix E: Budget Calculations*, Excel file available at https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update.

[9] The corrected calculations are based on EIA heat input data from the 923 Report Form and as published on the EIA website at http://www.eia.gov/electricity/data/browser/#/plant/50558/?freq=M&pin=. *See* Appendix B (CD-Rom Enclosure).

[10] At minimum, technical corrections using annual, adjusted EIA data (i.e., the EIA data EPA used in the Proposed Rule) likely still would raise OK Cogen's allocation.

B. The Requested Corrections Are Supported By The Final Rule

1. The Final Rule Calls for Multiple Historic Baseline Years

OK Cogen's request to EPA is straightforward: simply do what you said you would do (but did not actually do). The Final Rule calls for using a five-year (2011-2015) historic baseline period for heat input data, and an eight-year (2008-2015) historic baseline period for NOx emissions data. *See* Allocation TSD at 6-7. EPA's rationale for using multiple historic baseline years is sound: it helps ensure that outlier data from a single unrepresentative year (e.g., where heat input or NOx emissions levels were significantly lower than usual) does not skew the calculations.[11] As EPA recognizes, the power sector is susceptible to a range of variables affecting fuel use and emissions, including equipment failures, changing market forces, and weather patterns. *See* 81 Fed. Reg. at 74,566. One year of historic data cannot capture the inherent variability in a unit's operations from year to year, or ozone season to ozone season.

Nonetheless, EPA set Unit CC01's allocations based *solely on 2015* operations. 2015 was a highly unrepresentative year for the unit because of unexpected mechanical equipment failures.[12] ***The unit was out-of-service for repairs during most of the 2015 ozone season (from May 5 to July 31, 2015)***. As a result, fuel usage/heat input and NOx emissions for the 2015 ozone season were uncharacteristically low.[13] Indeed, the unit typically dispatches *more* during the ozone season than other times of the year. For the 2016 ozone season, Unit CC01's dispatch rate was higher, much closer to historic levels. OK Cogen believes this trend of higher dispatch will continue. Market forces are likely to drive more and more dispatch of natural gas-fired units as the coal-fired units prevalent in the region phase out of service.

EPA's reliance on solely 2015 CAMD data to establish the Unit CC01's allocations is arbitrary and capricious. It results in the exact outcome EPA tried to avoid through a multi-year allocation methodology, unfairly penalizing Unit CC01.

2. The Final Rule Calls for Data Substitution

Again, the requested corrections simply ask EPA to do what the Agency said it would do. EPA's prescribed methodology calls for using historic data from *up to two* different sources: (1) CAMD, if available for a given year; and (2) EIA, if CAMD data is unavailable for a given year. *See* Allocation TSD at 6-7. Indeed, for many units EPA *must* look to a historic data source other than CAMD to be able to use the multi-year baseline periods called for in the Final Rule. Prior to Phase I of the CSAPR program in 2015, many units, like Unit CC01, had no obligation to report data to CAMD under any EPA program. Unit CC01 has only a single year

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[11] *See* Allocation TSD at 7. EPA chose a multi-year heat input baseline because "[s]electing the three highest, non-zero ozone season heat input values within the five-year baseline reduces the likelihood that any particular single year's operations (which might be negatively affected by outages or other unusual events) determine a unit's allocation." *Id.* EPA chose a multi-year NOx emissions baseline "in order to capture the unit-level emissions before and after the promulgation of the original CSAPR. *Id.*

[12] While OK Cogen has an aggressive preventative maintenance program, unexpected equipment maintenance is a part of all power plant's operations.

[13] In 2014, Unit CC01 also experienced multiple ozone season outages due to mechanical equipment failures. The unit did not experience similar ozone season outages in 2011-2013.

of reported CAMD data (2015), but has multiple years of EIA data (to before 2008, the earliest relevant baseline year under the Final Rule). Under such circumstances, EPA's methodology calls for the Agency to use a combination of 2015 CAMD data and 2008-2014 EIA data. It is arbitrary and capricious for EPA not to apply this methodology to Unit CC01.

EPA also states it will look to publicly available, *reported* EIA data.[14] EPA does not state, in either the Final Rule or the Allocation TSD, that it will adjust EIA data from what is reported directly on the EIA forms.[15] EPA therefore should use *monthly (not annual), reported (not adjusted for combined-cycle or cogeneration units)* EIA data whenever EIA data is called for in allocation calculations. Monthly data is better than annual data with a crude 5/12 multiplier because monthly data more accurately reflects actual ozone season operations.[16] Reported heat input data is better than downward-adjusted heat input data for cogeneration and combined-cycle units because reported data more accurately reflects these units' actual fuel use, as well as their highly efficient processes.[17] Using monthly, reported EIA data also is consistent with EPA's treatment of CAMD data, which EPA did not adjust when incorporating it into the Final Rule's current allocation calculations. Treating EIA and CAMD data differently would be arbitrary and capricious.

C. EPA Should Issue the Technical Corrections Through a Direct Final Rule

EPA should issue the requested corrections through a direct final rule as an alternative to full notice-and-comment rulemaking.[18] Direct final rules rely on the Administrative Procedure Act's "good cause"

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[14] Specifically, EPA "used historical heat input and emissions data [EIA] forms, 860, 906, 920, and 923. These data are publicly available at http://www.eia.doe.gov/cneaf/electricity/page/data.html." Allocation TSD at 6.

[15] In the Proposed Rule, EPA appears to have altered OK Cogen's reported EIA data for Unit CC01 in two ways: (1) instead of looking at *monthly* data for ozone season months, EPA took *annual* data and multiplied it by 5/12 to estimate ozone season operations (because the ozone season comprises 5 months out of the year); and (2) instead of using total reported heat input values, EPA applied a downward "proportional nameplate capacity adjustment" to account for the fact that Unit CC01 is a combined-cyclele unit with both a gas turbine and a steam turbine that produce electricity (basically, EPA multiplied the gas turbine's share of total nameplate capacity (~59 percent) by total heat input, thereby "discounting" the total heat input by about 41 percent). Email correspondence with EPA (Nov. 7, 2016) and EPA contractors (Nov. 21, 2016). Both of these data manipulations are inappropriate. EPA did not apply either of these changes to OK Cogen's EIA ozone season data in the Original CSAPR or Supplemental CSAPR Rules. Instead, EPA historically has used reported, monthly EIA data—as it should again here.

[16] The 5/12 ozone season multiplier incorrectly assumes that Unit CC01 operates more or less the same during all 12 months of the year. In fact, Unit CC01 operates *significantly more* during the ozone season because it is a highly-efficient natural gas-fired unit that is called on during peak periods of electricity demand, which often coincide with ozone season summer months. Further, monthly EIA data for May-September for 2008-2014 is available for Unit CC01. There is no good reason not to use it.

[17] The "proportional nameplate capacity adjustment" for cogeneration and combined cycle units misunderstands how these units operate and punishes these units for being efficient. At a typical combined-cycle plant like Unit CC01, waste heat (exhaust) from the gas turbine produces steam that powers a steam turbine to generate extra electricity. *All* fuel consumed in combined-cycle units is therefore used in electricity generation: fuel is combusted in the gas turbine to either produce power or produce steam, which produces power. The adjustment ignores this fact and underestimates how much of the unit's heat input goes toward electricity production. Therefore, the adjustment punishes units for employing a more efficient process that reuses gas turbine exhaust to produce steam and more electricity, rather than just venting it off.

[18] A direct final rule is "a rule that is issued in final form, without prior notice and comment, that becomes effective on a particular date unless adverse comment is submitted within a specified period of time." EPA Office of General Counsel, *Direct Final Rulemaking Guidance for EPA Rule Writers*, Attachment 1, § 2 (1998). Available at

exemption from notice-and-comment rulemaking,[19] while giving the Agency "the benefit of any public input that may unexpectedly surface." Direct Final Rulemaking Guidance at § 2 (citation omitted). EPA uses direct final rules for "noncontroversial rules where [the Agency does not] expect adverse comment," including routine or minor actions. *Id.* at §§ 4, 6. EPA previously has issued direct final rules under the CSAPR program. *See, e.g., Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 77 Fed. Reg. 10,342 (Feb. 21, 2012). Here, the corrections to EPA's allocation calculations for Unit CC01 are a non-controversial, minor action unlikely to attract adverse comment because they (1) would affect only a subset of units within a single state; and (2) are necessary to correct clear technical errors in EPA's application of the Final Rule's allocation methodology.

Further, time is of the essence. A direct final rule generally is a more efficient procedural mechanism than notice-and-comment rulemaking. The 2017 ozone season begins in just over five months. OK Cogen needs to get the correct amount of allowances on the books for Unit CC01 as soon as possible in order to plan, and carry out, its compliance strategy for the 2017 ozone season.

II. Reconsideration is Required by the Clean Air Act

A. Legal Standard

The Clean Air Act requires that EPA grant reconsideration of a final rule when a petitioner raising an objection can show that: (1) it was impracticable to raise the relevant objections during the comment period or the grounds for such objection arose after the period for public comment; and (2) the objection is of central relevance to the outcome of the rule. 42 U.S.C. § 7607(d)(7)(B). In such a situation, reconsideration is mandatory: EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added).

The notice-and-comment requirements of the Clean Air Act and the Administrative Procedure Act further require that EPA's "proposed rule and its final rule . . . differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). A "final rule is a 'logical outgrowth' of a proposed rule only if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Id.* at 998. The "test is whether a new round of notice and comment would provide the first opportunity for interested parties to offer comments that could persuade the agency to modify its rule." *Id.* at 996.

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https://yosemite.epa.gov/oaqps/rdms.nsf/591caf4ab155e210852566de00539f57/c92ad1453ad5de6885256728006a0f30!OpenDocument ("Direct Final Rulemaking Guidance"). In conjunction with a direct final rule, EPA's typical practice is to simultaneously publish a separate, parallel proposed rule. If EPA receives significant adverse comments on the direct final rule, the Agency will withdraw the direct final rule and address the public comments in a subsequent final rule based on the parallel proposed rule. *Id.* at § 4.

[19] 5 U.S.C. § 553(b)(3)(B) (Section 553's notice-and-comment requirement does not apply "when the agency for good cause finds . . . that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.").

B. Failure to Comply with Notice and Comment Requirements

The grounds for OK Cogen's objection arose after the public comment period. Before the Final Rule was issued, OK Cogen could not have expected or anticipated that EPA would set Unit CC01's allocations based on a *single* historic baseline year and *only CAMD* data. Both the Proposed and Final Rules call for EPA to set unit allocations using multiple historic baseline years[20] and EIA data-substitution. EPA did this in the Proposed Rule, but not in the Final Rule. What EPA did in the Final Rule looks like a clear technical error. It would be impracticable, if not impossible, for OK Cogen to have anticipated and submitted comment on an error that EPA *had not yet committed* during the public comment period, but committed for the first time in the Final Rule.

OK Cogen therefore had no meaningful opportunity to comment on the final allocations. EPA did not provide notice of or seek comment on the possibility of switching from *multiple* to *single* historic baseline years, or from using *both CAMD and EIA data* to *only CAMD* data. Had EPA done so, OK Cogen would have submitted comments that these changes would arbitrarily and unfairly penalize Unit CC01. As it stands, OK Cogen was caught by surprise by the new unit-level allocation data inputs. EPA may not "use the rulemaking process to pull a surprise switcheroo on regulated entities." *Envtl. Integrity Project*, 425 F.3d at 998.

In yet another "surprise switcheroo," OK Cogen was stunned by the cut in Oklahoma's budget from the Proposed to the Final Rule—*the biggest reduction of any state*. This reduction resulted largely from the significant revisions EPA made to its formula for calculating model-predicted statewide emissions. Because state budgets dictate the size of the available allowance "pool" for units within the state, the drop in Oklahoma's budget contributed to the drop in OK Cogen's allocations under the Final Rule. Had EPA provided notice of its plan to drastically reduce Oklahoma's budget, OK Cogen would have submitted comments explaining how the revised formula significantly overestimates the amount of emissions reductions achievable in the state and results in an overly stringent budget.

OK Cogen's objection also is of central relevance to the outcome of the rule. EPA's data errors have left OK Cogen with a major, unexpected allowance shortfall for the 2017 ozone season. Correcting these errors is critical to OK Cogen's ability to plan for and achieve compliance with the CSAPR Update Rule, especially given the extremely near-term compliance timeframe for the 2017 ozone season. Correcting these errors also would provide a fairer and more representative distribution of allowances within Oklahoma, allowing for more efficient compliance on a state-wide level. Compliance feasibility and efficiency are central to the outcome of the CSAPR Update Rule.

CONCLUSION

In summary, OK Cogen requests that EPA reconsider the CSAPR Update Rule. As described above, EPA must recalculate the allowance allocations for OK Cogen's Unit CC01 using a corrected methodology that is based on multiple historic baseline years (not just one year) and data-substitution using a combination of

[20] The only difference between the Proposed and Final Rule methodologies was a one-year shift in the relevant baseline periods. Because 2015 data was not yet available, the Proposed Rule calculated allowance allocations based on a 2010-2014 heat input baseline period and a 2007-2014 NOx emissions baseline period. The Final Rule uses a 2011-2015 heat input baseline period and a 2008-2015 NOx emissions baseline period. *See* Allocation TSD at 6.

CAMD and EIA data (not just CAMD data). EPA should use monthly, reported (unadjusted) data for these calculations. EPA should issue these technical corrections through a direct final rule because they are noncontroversial and are needed on an extremely short time frame.

Sincerely,

James R. Beers

James R. Beers
LLC Managing Member

Enclosures (CD-Rom):

Appendix A: Revised 2017 CSAPR Update Allowance Allocation Calculations for Oklahoma Cogeneration LLC

Appendix B: Published EIA Data for Oklahoma Cogeneration LLC 2008-2014

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Appendices

Along with an electronic submission of this petition, OK Cogen is supplying EPA with a CD-Rom containing the two Appendices (Appendix A and B). The Appendices are Excel datasheets and workbooks demonstrating the calculations described in this petition. The CD-Rom contains both a "locked" (i.e., password-protected, read-only) version and an "unlocked" courtesy working copy of each file. Appendix A-1 is a modification of EPA's Final Rule Allocation Spreadsheet TSD. Detailed revised calculations for the reapportionment analysis are contained in Columns AB-AI.

To: Dravis, Samantha[dravis.samantha@epa.gov]
Cc: Kime, Robin[Kime.Robin@epa.gov]
From: Paul Balserak
Sent: Thur 3/16/2017 4:13:32 PM
Subject: Sector Performance Report
EPA Sector-Report-2008 Full Version.pdf

Hi Samantha,

Tom Gibson asked me to follow-up with you regarding yesterday's meeting. Attached please find the 2008 Sector Performance Report that you all discussed. If you have any questions at all, don't hesitate to let me know.

Best regards,

Paul

Paul Balserak

Vice President, Environment

American Iron and Steel Institute

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Ex. 6 - Personal Privacy (mobile)

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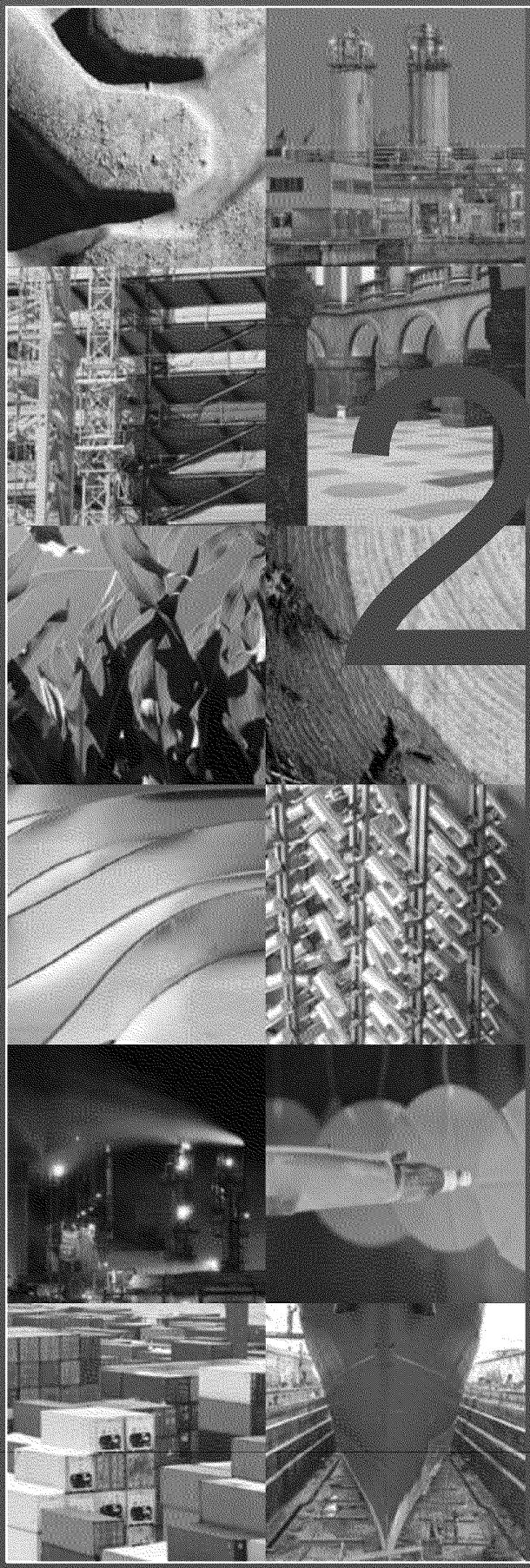

2008 Sector Performance rePort

SectorStrategies

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US EPA ARCHIVE DOCUMENT

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Washington, D.C. 20460

Office Of POLICY,
ECONOMICS, AND INNOVATION

Dear Reader,

This report provides information on the environmental performance of some of America's leading manufacturing and nonmanufacturing sectors. Together, the 12 sectors profiled represent more than 856,000 entities, employ more than 12.6 million people, and contribute more than $3.5 trillion annually to the U.S. economy. This report is an important tool for measuring the performance of these sectors and for determining how we can build on that progress going forward.

Developed by EPA's Sector Strategies Division, in cooperation with sector trade associations and many other stakeholders, this report provides a comprehensive look at the environmental impacts and trends of each sector. The data, drawn primarily from government databases, show many improvements in performance, such as emissions reductions for many pollutants, both in terms of the total amounts emitted and per individual unit of production.

Thanks to the many trade associations who worked with us to make this valuable resource possible. Their willingness to share additional data, experiences, and perspectives underscores their commitment to the environment and to building a productive relationship with EPA. Thanks also to the many other contributors in governmental and non-governmental organizations who share our interest in these sectors.

As you read this report, you will learn more about these important sectors, the steps they are taking, and the results they are bringing about to protect the environment, improve economic competitiveness, and seek a sustainable future for America.

Charles Kent, Director
Office of Cross-Media Programs
Office of Policy, Economics, and Innovation
U.S. Environmental Protection Agency

US EPA ARCHIVE DOCUMENT

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Welcome to U.S. Environmental Protection Agency's (EPA) 2008 *Sector Performance Report*, the third in a series started in 2004.[1] The report provides a comprehensive picture of the environmental performance of 12 sectors of the U.S. economy, currently and over time. The sectors have a significant collective impact environmentally and economically. They are:

- Cement Manufacturing
- Chemical Manufacturing
- Colleges & Universities
- Construction
- food & beverage Manufacturing
- forest Products
- Iron & steel
- Metal Casting
- oil & Gas
- Paint & Coatings
- Ports
- shipbuilding & ship Repair

PRefaCe

We provide context in the Executive Summary by, for example, comparing the sectors to the economy as a whole. In the following chapters, we provide for each sector an economic and environmental overview, detailed data on primary environmental indicators, and case studies on selected issues of interest.

Launched in 2003, and succeeding the Sustainable Industries Program launched in 1990, the Sector Strategies Program promotes sector-wide environmental gains in the 12 sectors. We work with sector trade groups and many other stakeholders to reduce pollution, conserve resources, lessen unnecessary administrative burden, measure corresponding performance results, and identify additional opportunities through quantitative metrics.

New in this Report

- Environmental data are presented in two ways—absolute and normalized:
  - Absolute emissions indicate the total amount emitted by the sector nationwide, reflecting the actual environmental impact at a given time.
  - Normalized data are adjusted by amount or value of product produced. Normalizing illuminates performance trends without highlighting changes caused by increases or decreases in production due to price or other externalities.[2]
- Economic trends over the period covered: 1996-2005
- Maps showing sector facility locations or concentrations
- New or expanded sectors:
  - Chemical Manufacturing
  - Food & Beverage Manufacturing
  - Oil & Gas
- Expanded information on indicators such as energy use and greenhouse gas (GHG) emissions

Major Sources of Data

Energy

Most of our energy use data come from the U.S. Department of Energy's (DOE) statistical agency, the Energy Information Administration (EIA). Every four years, EIA sends many manufacturers the Manufacturing Energy Consumption Survey (MECS) and extrapolates the responses to represent the full universe of manufacturers.[3]

Criteria Air Pollutants

Data on criteria air pollutants (CAPs) come from EPA's National Emissions Inventory (NEI). EPA prepares this national database every three years, based on input from state, tribal, and local air pollution control agencies; industry-submitted data; other EPA databases; and EPA emission estimates.[4]

Air, Water, and Waste in the Toxics Release Inventory

Data on other air emissions, on water discharges, and on management of chemicals in waste are from EPA's annual Toxics Release Inventory (TRI), based on reports filed by more than 23,500 facilities across the country.[5]

Toxicity of Air Emissions

EPA's Risk-Screening Environmental Indicators (RSEI) model generates the relative toxicity scores for air emissions.[6]

Hazardous Waste

Pursuant to the Resource Conservation and Recovery Act (RCRA), information on hazardous waste generation is from EPA's *National Biennial RCRA Hazardous Waste Report* (BR), based on reports from large quantity generators and treatment, storage, and disposal facilities.[7] Note that,

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Key to our work is collaboration with numerous stakeholders, including particular trade associations that participate in our program. They are:

Cement Manufacturing	Portland Cement Association
Chemical Manufacturing	American Chemistry Council Synthetic Organic Chemical Manufacturers Association
Colleges & Universities	American Council on Education Association for the Advancement of Sustainability in Higher Education Association of Higher Education Facilities Officers Campus Consortium for Environmental Excellence Campus Safety, Health and Environmental Management Association National Association of College and University Business Officers
Construction	Associated General Contractors of America
Food & Beverage Manufacturing	American Meat Institute Grocery Manufacturers Association
Forest Products	American Forest & Paper Association
Iron & Steel	American Iron and Steel Institute Steel Manufacturers Association
Metal Casting	American Foundry Society North American Die Casting Association
Oil & Gas	American Petroleum Institute American Exploration and Production Council Independent Petroleum Association of America
Paint & Coatings	National Paint & Coatings Association
Ports	American Association of Port Authorities
Shipbuilding & Ship Repair	American Shipbuilding Association Shipbuilders Council of America

unlike TRI, BR tracks entire waste streams, rather than only certain chemicals.

Key Data Considerations

Sector Definitions

Many data sources reflect only certain segments of a sector; others define certain sectors more broadly than we do. Most often, sectors are defined either by standard classification codes, such as the North American Industry Classification System (NAICS), or by lists of facilities based on our sector definitions. Endnotes for each chapter, and the Data Sources, Methodologies, and Considerations chapter, clarify how each sector is defined for our work and for the various databases used to generate data.

Data Completeness

Reporting thresholds and other factors influence how many facilities report to a given database and the extent to which they report on their overall footprint. The number of facilities within a sector that report to a particular database, or that report different media impacts within a database (such as air or water), can differ significantly, even within a sector. See the Data Sources, Methodologies, and Considerations chapter and sector chapter endnotes for discussion of data completeness.

Currency of Data

We use the most recent data available, but few databases are updated at the same time. See individual endnotes and the Data Sources, Methodologies, and Considerations chapter for information about the currency of the underlying data. Depending on data availability, the time period covered may vary from the years this report generally covers, which are 1996-2005.

Drivers and Barriers

The Sector Strategies Program analyzes many regulatory and nonregulatory factors that affect environmental management decisions among facilities in a given sector. These behavioral leverage points can influence the environmental performance of a facility or sector on one or more metrics. We consider these legal, technical, economic, behavioral, and other factors to be better able to develop policy and program actions that will provide strong drivers and reduce major barriers to improved environmental performance. However, the factors are beyond the scope of this report, which focuses on available quantitative data trends.

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This report presents the latest environmental performance information for 12 sectors. Because every sector is unique, sector chapters provide maps, economic information, and detailed explanations, analysis, and discussions of the data presented.

To provide context for the report, this Executive Summary begins by presenting the impacts of all 12 sectors using several national and global indicators.[1]

Comparing data across sectors can illuminate broader trends and opportunities. This Executive Summary includes sector-specific data gathered side-by-side for the 9 sectors with the most environmental data.

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

executive summary

Economic Overview

Number of Facilities	856,836
Employment	12.6 million—more than 10% of U.S. workers
Economic Productivity	
Value of Shipments & Construction Put in Place	$3.2 trillion—with Revenue, below, 28% of Gross Domestic Product
Revenue	
Colleges & Universities	$341 billion
Ports	$5.5 billion

Latest Environmental Statistics

Energy Use	14.5 quadrillion Btu
Emissions of Criteria Air Pollutants	5.8 million tons
Air Emissions (TRI)	519.5 million pounds
Water Discharges (TRI)	178.2 million pounds
Land Disposals (TRI)	658.1 million pounds
Recycling, Energy Recovery, or Treatment (TRI)	14.8 billion pounds
Hazardous Waste Generated	30.6 million tons

Global Standing: Examples

Cement Manufacturing	U.S. is third, behind China and India
Chemical Manufacturing	U.S. is world's largest producer, generating more than $635 billion a year
Construction	U.S. is first, with spending of $873.1 billion in 2003—out of $3.98 trillion spent by the 55 largest nations
Food & Beverage Manufacturing	U.S. is second, behind the European Union, and followed by Japan and China
Forest Products	U.S. is world's largest producer and consumer
Iron & Steel	U.S. is third behind China, which makes nearly four times more, and Japan

General Comparisons

Mostly Small Businesses	Construction, Metal Casting, Shipbuilding & Ship Repair
Most Widespread	Construction, Colleges & Universities, Food & Beverage Manufacturing
Most Concentrated	Iron & Steel, Ports, Shipbuilding & Ship Repair
Include Government Facilities	Colleges & Universities, Ports, Shipbuilding & Ship Repair

Economic Trends 1996-2005

Facilities	Three sectors ended the period having added facilities, led by Construction. At least half of the sectors ended with fewer facilities.
Employees	The 12 sectors were split in terms of whether they added or lost employees.
Value of Shipments, Value of Construction Put in Place, or Revenue	At least 9 sectors showed increases that were, in many cases, significant.

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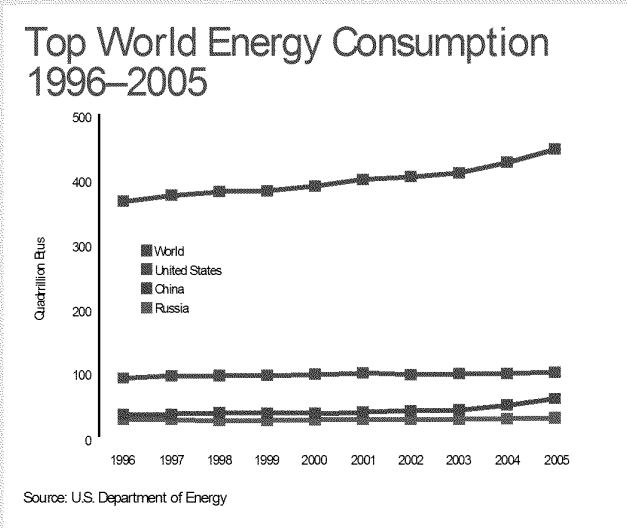
Energy Use

The eight sectors for which we have calculations used an estimated 14.5 quadrillion British Thermal Units (Btu) in 2002, which was nearly 15% of total domestic energy consumption of 97.9 quadrillion Btu.[2] World energy consumption in 2002 was 409.7 quadrillion Btu. The U.S. consumed more energy than any other country, followed by China, Russia, and Japan, although long-term trends appear likely to change the rankings.[3] From 1996 to 2005, the U.S. industrial sector gradually consumed less energy, while residential, commercial, and especially transportation energy consumption rose.[4] See individual sector chapters for discussions of energy use, trends, and opportunities.[5]

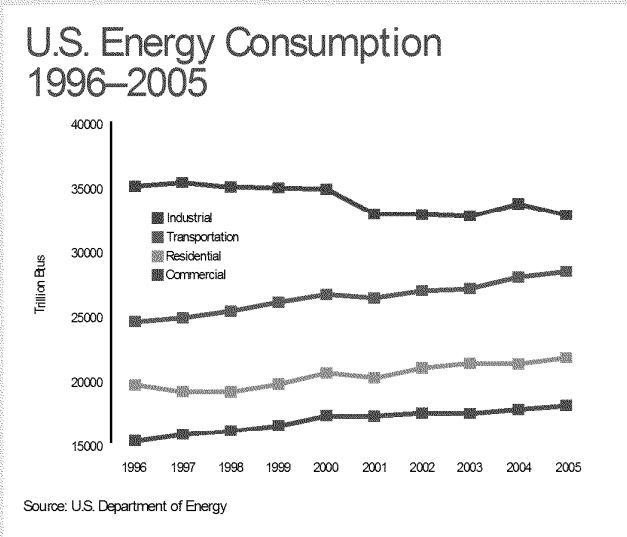


Energy Use and Air Emissions

Energy use causes impacts such as direct air emissions, which are reflected in this report. Other impacts, such as offsite (indirect) emissions, are generally beyond the scope of this report, as are energy-related mobile source emissions, such as from freight shipping.

Primary among on-site energy use-related air emissions are criteria air pollutants (CAPs) from combustion. The largest components of such CAP emissions are sulfur dioxide (SO_2), nitrogen oxides (NO_X), and larger particulates from coal combustion. Most SO_2 results from combusting sulfur-containing fuels, especially coal. Combustion also generates NO_X, although emissions vary less by fuel type than for SO_2. Particulate matter (PM) can be ash and dust from combustion of coal or heavy oil, or very fine particulates ($PM_{2.5}$) largely composed of aerosols formed by NO_X and SO_2 emissions.

Excepting emissions from off-road vehicles, volatile organic compound (VOC) and carbon monoxide (CO) combustion emissions are a much smaller fraction of total energy-related emissions. CO is a product of incomplete combustion, but the largest source is vehicles. VOCs can also result from incomplete combustion, but the largest energy-related sources are fugitive emissions from fuel storage tanks and pipelines and combustion-related vehicle emissions. Fossil fuel combustion also generates carbon dioxide (CO_2), which is a greenhouse gas (GHG). Other energy-related GHG emissions, such as methane (CH_4), are far less substantial.



Greenhouse Gases

A sector's GHG footprint includes direct and indirect emission sources. Direct emission sources are those for which there is direct control, such as fossil fuel combustion and process emissions. Indirect emission sources are mainly those attributed to the generation of purchased electricity. Both EPA and the U.S. Department of Energy (DOE) estimate economy-wide GHG emissions, but neither provides sector-specific footprints that include direct and indirect emissions; data to generate such estimates are not readily available.

In 2005, total U.S. GHG emissions were 7,260 million metric tons of CO_2 equivalent, having risen 8.5% since 1996.[6] Including emissions from generation of purchased electricity, industry and transportation each accounted for 28% of total U.S. GHG emissions in 2005. In all sectors except agriculture, CO_2 accounted for more than 80% of GHG emissions, primarily from the combustion of fossil fuels.[7]

Although some gases have a higher global warming potential (GWP) per unit than CO_2, CO_2 is by far the dominant GHG emitted in terms of volume and total GWP emitted each year. EPA reports on CO_2 emissions from fossil fuel combustion for broad sectors of the U.S. economy. For CO_2 emissions other than fossil fuel use, EPA reports on particular sources, such as industrial processes in the Cement Manufacturing and Iron & Steel sectors.[8]

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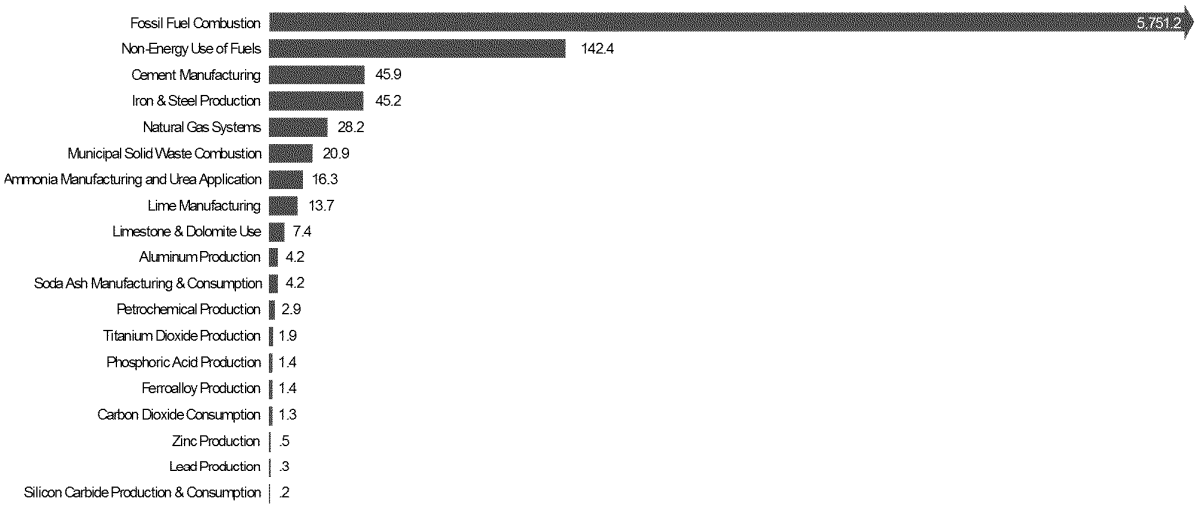
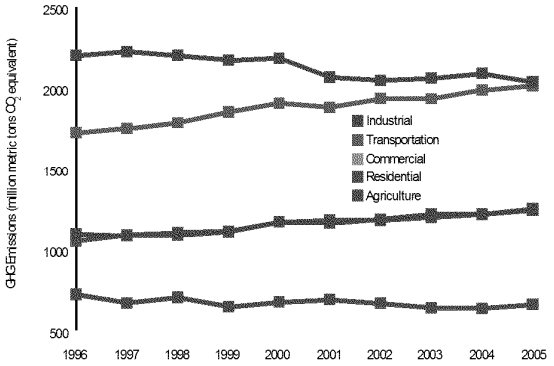
U.S. CO_2 Sources in Million Metric Tons of CO_2 Equivalent 2005



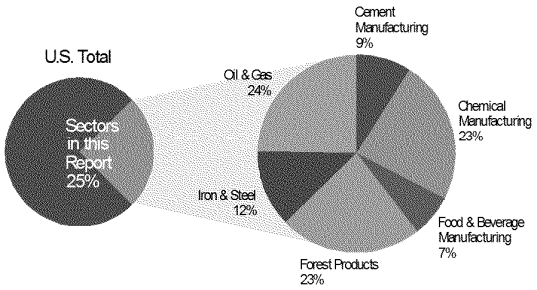
Source: U.S. Environmental Protection Agency

U.S. GHG Emissions 1996–2005
with Electricity-Related Emissions Distributed



Source: U.S. Environmental Protection Agency

Criteria Air Pollutant and VOC Emissions 2002



Note: Sectors at 1% or less are not represented.
Source: U.S. Environmental Protection Agency

Direct CO_2 and CH_4 combined process emissions from the Iron & Steel sector fell 33% from 1996 to 2005, although total steel produced was relatively unchanged.[9] Direct CO_2 process emissions from Cement Manufacturing in the same time period rose 24%, while the sector's cement production also rose 24%.[10] Trade associations for these two sectors, as well as for the Forest Products sector, estimate their members' total GHG footprint, including carbon "sinks" such as forests and products. See the respective chapters.

Criteria Air Pollutants and VOCs

Sectors in this report, which emit CAPs and VOCs from energy use and from other processes and activities, emitted 25% of total U.S. point source CAP and VOC emissions in 2002.[11] Sector-specific trend data are not available for CAP and VOC emissions.[12]

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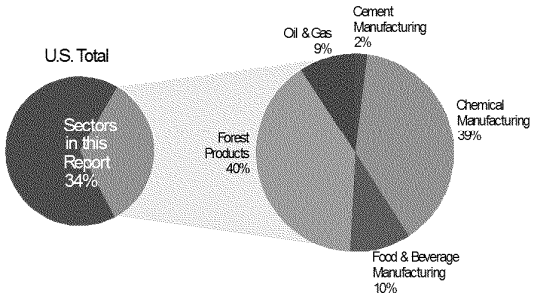
Sector Data Side by Side

The following sections present sector data for several sectors together. Because the sectors vary so substantially in size, scope, makeup, data availability, relevant drivers and barriers, and numerous other factors, a direct-one-on-one comparison of their performance would be inappropriate. To consider energy-related air emissions, for example, a sound analysis should also include sector-specific information on fuel flexibility, which is driven by percentages of fuel used for energy or for raw materials and other considerations.

TRI Air Emissions

In 2005, the 9 of our 12 sectors that report to EPA's Toxics Release Inventory (TRI) reported emitting 520 million lbs. of TRI chemicals, out of 1.5 billion lbs. emitted by all TRI reporters nationwide. Of the nine sectors, absolute total air emissions fell from 1996-2005 for all but one, while absolute emissions of hazardous air pollutants (HAPs) fell for all nine. To understand the sector-specific data, including apparent spikes, dips, and other trends, see individual sector chapters.

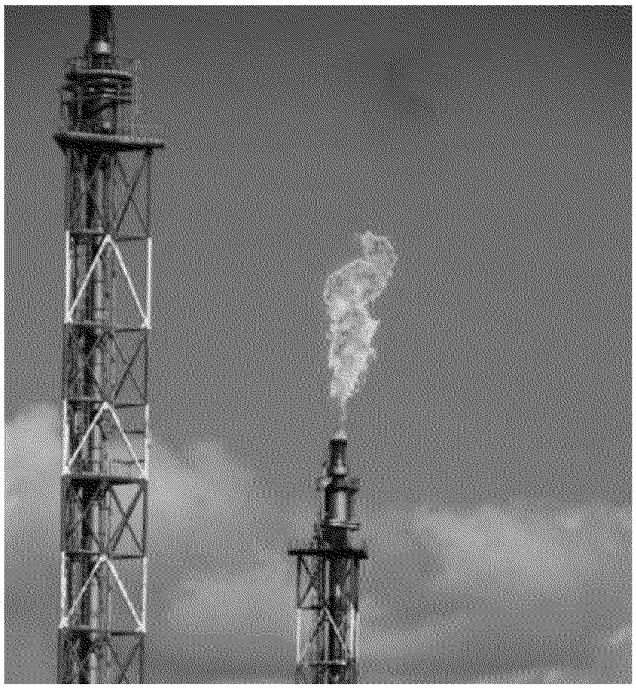
TRI Air Emissions 2005



Source: U.S. Environmental Protection Agency

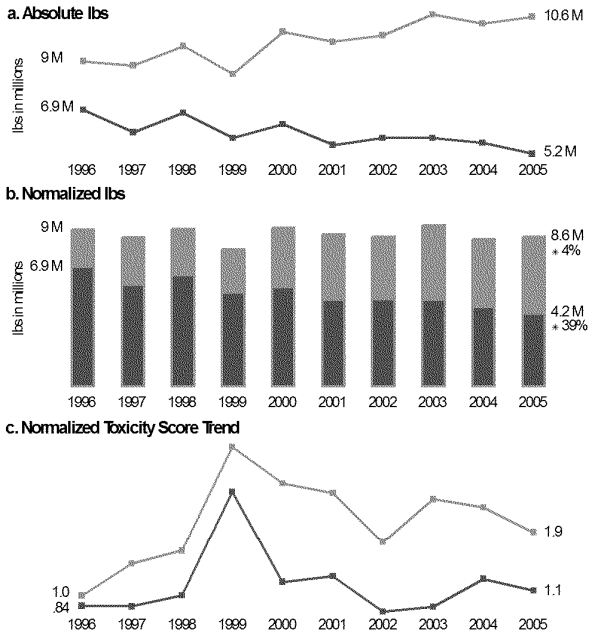
RSEI

To consider toxicity, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns TRI chemicals a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., lbs. of mercury released to air) by it to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI. Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are released. For chemical categories such as chromium, RSEI conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium). Thus, Toxicity Scores are overestimated for some chemical categories. Summing the Toxicity Scores for all of a sector's air emissions reveals a Normalized Toxicity Score Trend; these fell from 1996-2005 for most sectors, but rose for several. To better understand apparent spikes and trends, see individual sector chapters. The figures below show TRI air emission trends by corresponding bar and data points for each year between 1996 and 2005.



TRI Air Emissions Across Sectors 1996–2005

CEMENT MANUFACTURING



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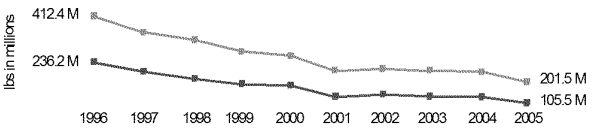
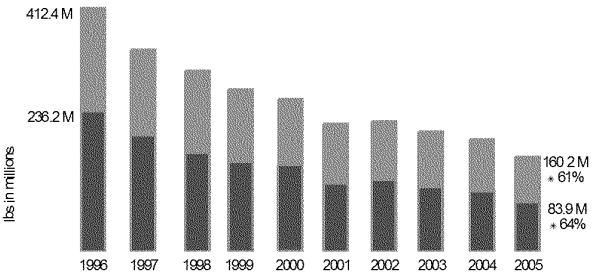
CHEMICAL MANUFACTURING

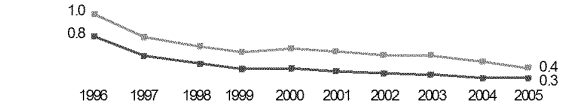
a Absolute lbs



b. Normalized lbs



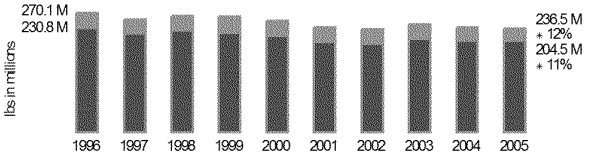
c. Normalized Toxicity Score Trend



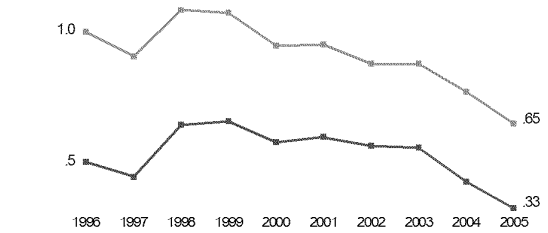
FOREST PRODUCTS

a Absolute lbs

b. Normalized lbs

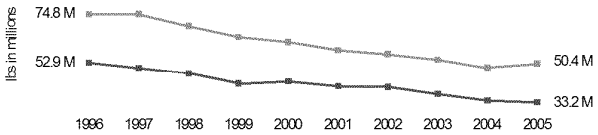


c. Normalized Toxicity Score Trend

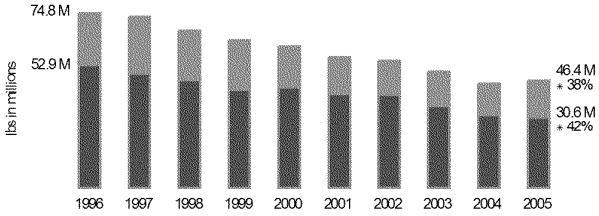


FOOD & BEVERAGE

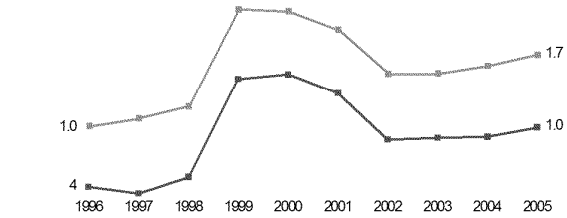
a Ab o ute lbs



b. Normalized lbs

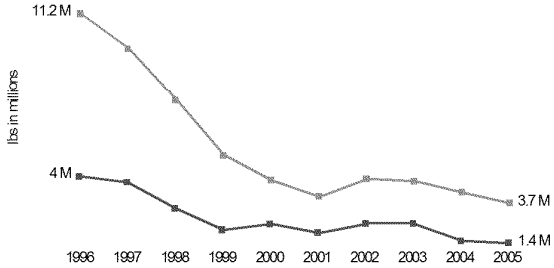


c. Normalized Toxicity Score Trend

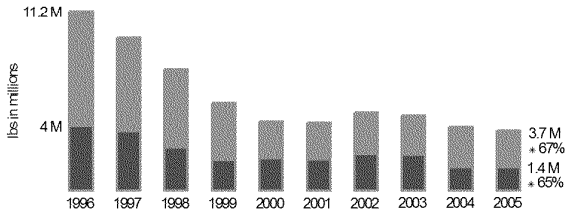


IRON & STEEL

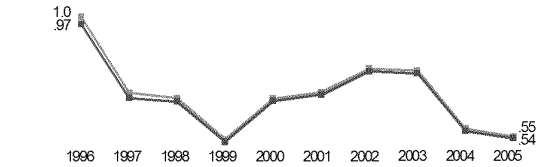
a. Absolute lbs



b. Normalized lbs



c. Normalized Toxicity Score Trend



FOr SectOr-SpeciFic Air chArtS

All TRI Chemicals, including HAPs All TRI HAPs

Note: Normalized by annual value of shipments or production.

Sources: U.S. Environmental Protection Agency, U.S. Geological Survey, U.S. Department of Commerce, American Foundry Society, U.S. Department of Energy

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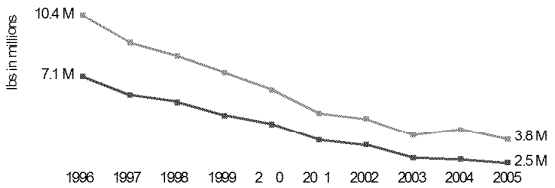
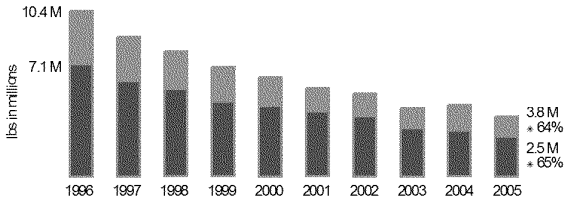
TRI Air Emissions Across Sectors 1996–2005 (continued)

METAL CASTING

a. Absolute lbs



b. Normalized lbs

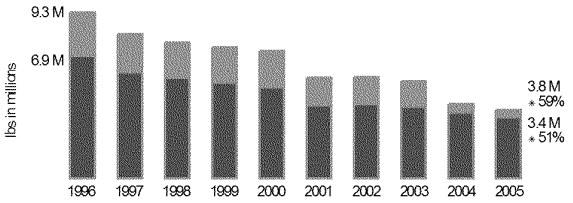


c Normalized Toxicity Score Trend

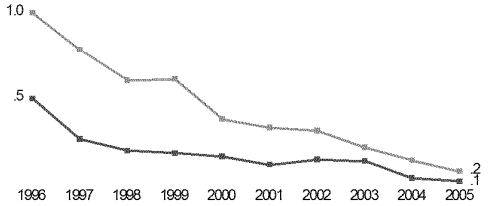
PAINT & COATINGS

a. Absolute lbs

b. Normalized lbs

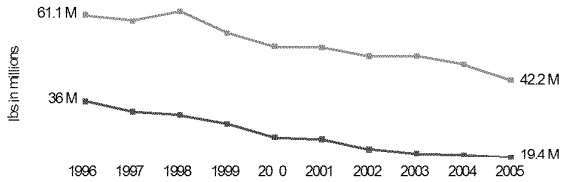


c. Normalized Toxicity Score Trend

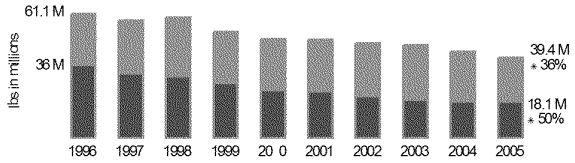


OIL & GAS (PETROLEUM REFINING)

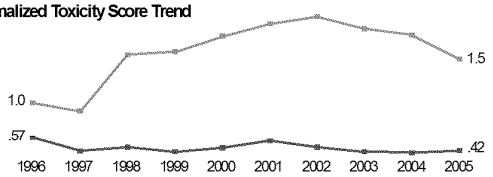
a. Absolute lbs



b. Normalized lbs

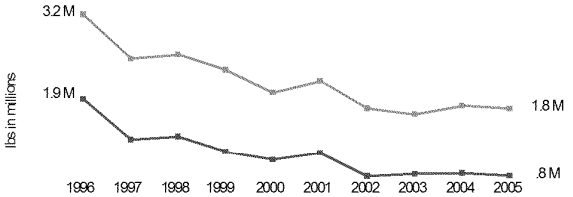


c. Normalized Toxicity Score Trend

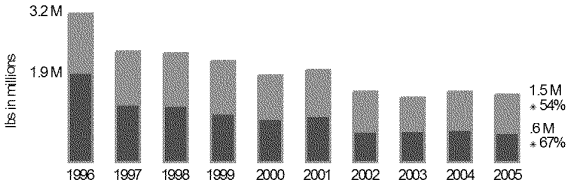


SHIPBUILDING & SHIP REPAIR

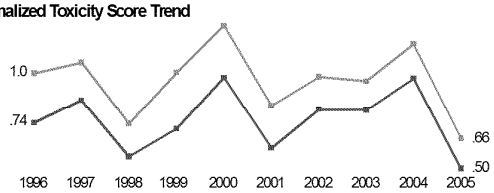
a. Absolute lbs



b. Normalized lbs



c. Normalized Toxicity Score Trend



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Waste Management

This section includes information on hazardous wastes and on TRI chemicals managed as waste.[13] EPA emphasizes reducing waste generation whenever possible and, if waste is generated, minimizing the quantity that is released or disposed by instead increasing recycling, energy recovery, or treatment. TRI includes the volume of the toxic chemicals within a waste stream, while Resource Conservation and Recovery Act (RCRA) reporting on hazardous wastes encompasses the volume of the entire waste or waste stream that meets the definition of RCRA hazardous waste. See individual sector chapters for explanations of apparent spikes and trends.

Hazardous Waste Generated and Managed 2005

	Hazardous Waste Generated (Tons)	Hazardous Waste Managed (Tons)
Sectors in this Report	30,557,598	32,993,131
U.S. Total	38,350,145	42,825,913
Sectors in this Report as a Percentage of the U.S. Total	**80%**	**77%**
Sector		
Cement Manufacturing	17,195	30,641
Chemical Manufacturing	23,861,975	26,138,338
Colleges & Universities	26,158	23,544
Construction	17,058	16,437
Food & Beverage Manufacturing	3,071	2,367
Forest Products	135,541	396,336
Iron & Steel	1,395,650	1,269,594
Metal Casting	30,274	28,210
Oil & Gas (Petroleum Refining)	5,063,461	5,081,593
Paint & Coatings	145,832	147,595
Shipbuilding & Ship Repair	7,214	6,071

Source: U.S. Environmental Protection Agency

Filling in the Picture

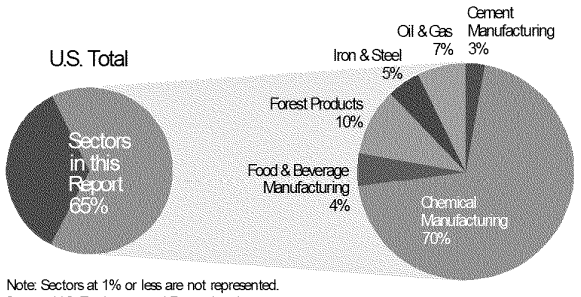
For waste and other indicators, we use available data to understand and improve sectors' environmental performance. Where data are incomplete, inadequate, or unavailable, we try to fill the gaps to provide a more complete picture. We determine what needs to be measured, what is already measured, and how to find—or create appropriate surrogates for—remaining needed information. See, for example, the discussion of GHG emissions in the Construction chapter, which draws upon DOE fuel sales data.

States also may provide useful information. See information from several states about recycling construction and demolition debris, in the Construction chapter.

When government data are unavailable, information from private organizations may be useful, such as the American Association of Port Authorities' survey cited in the Ports chapter.

When no data are available, we sometimes assist in preparing tools for generating future data. As discussed in the Shipbuilding & Ship Repair chapter, we are working with the American Shipbuilding Association and the Shipbuilders Council of America to develop a tool for individual facilities to measure their GHG emissions, which could enable those groups to provide better data on the sector's overall GHG emissions in the future.

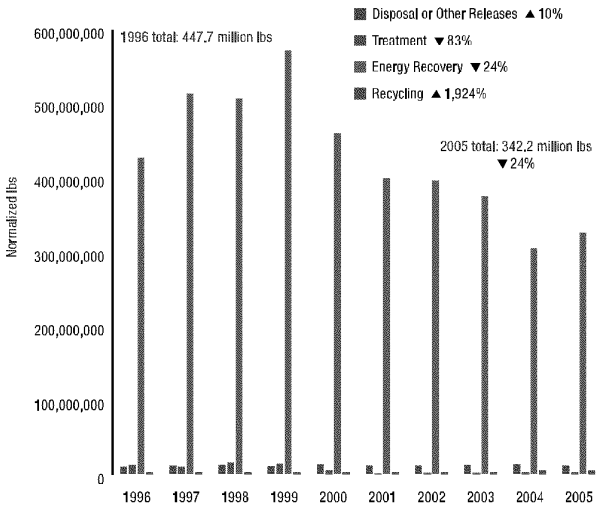
TRI Waste Management 2005



Note: Sectors at 1% or less are not represented.
Source: U.S. Environmental Protection Agency

TRI Waste Management Across Sectors 1996-2005

CEMENT MANUFACTURING



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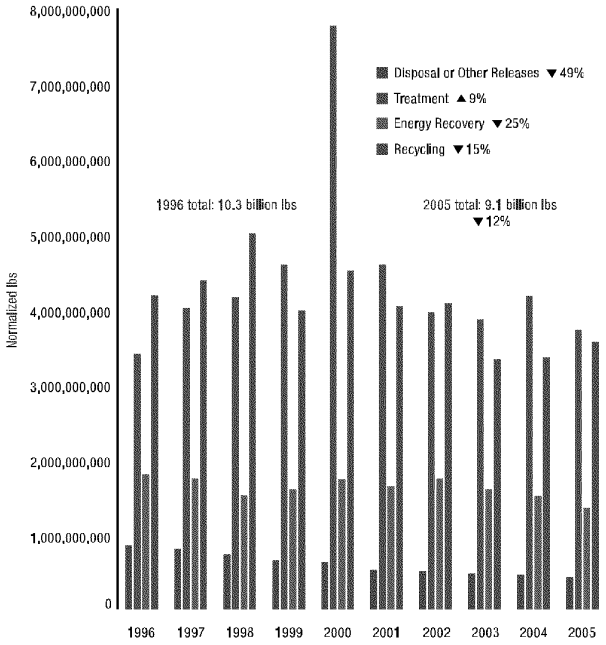
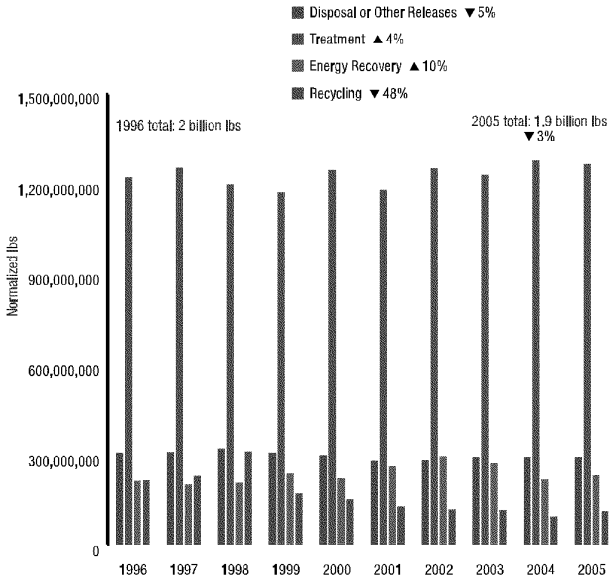
TRI Waste Management Across Sectors 1996-2005 (continued)

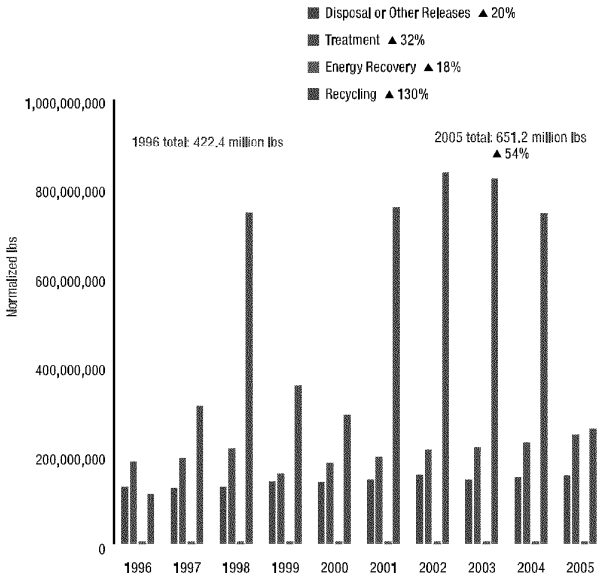
CHEMICAL MANUFACTURING



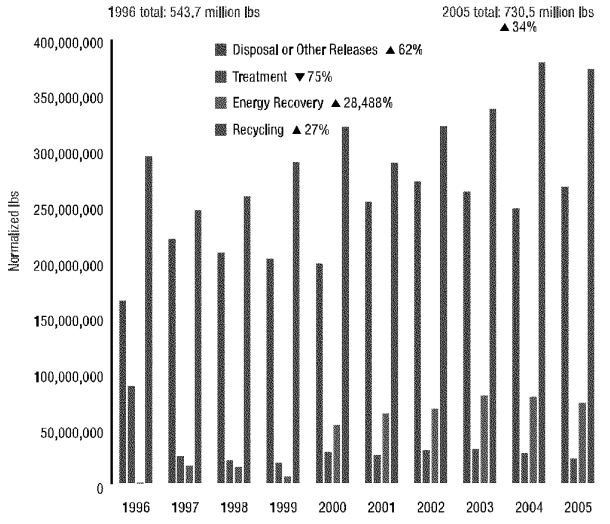
FOREST PRODUCTS



FOOD & BEVERAGE



IRON & STEEL



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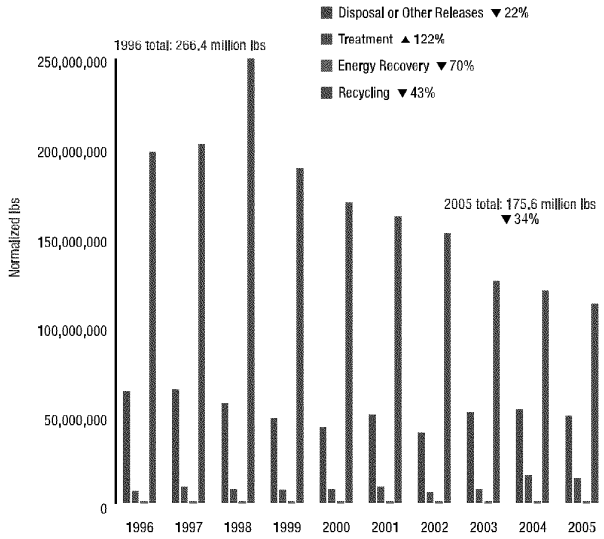
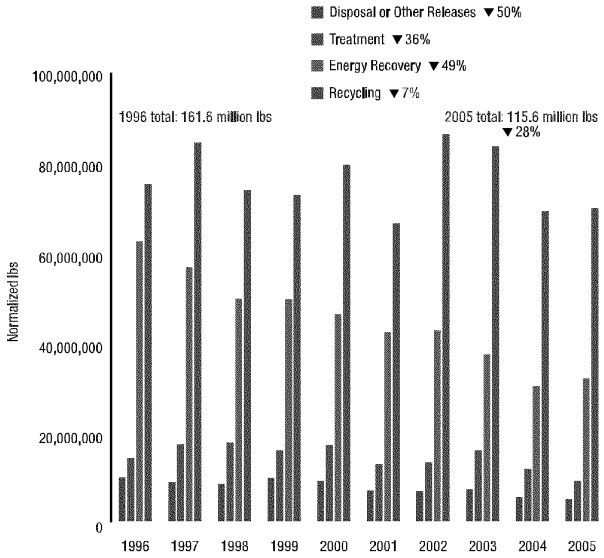
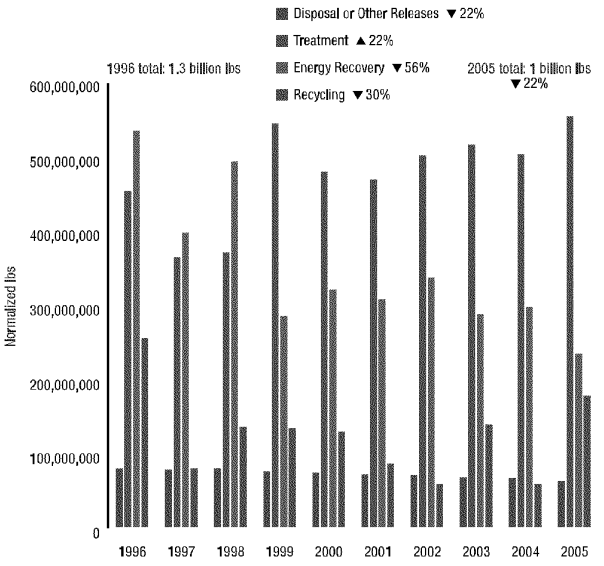
METAL CASTING



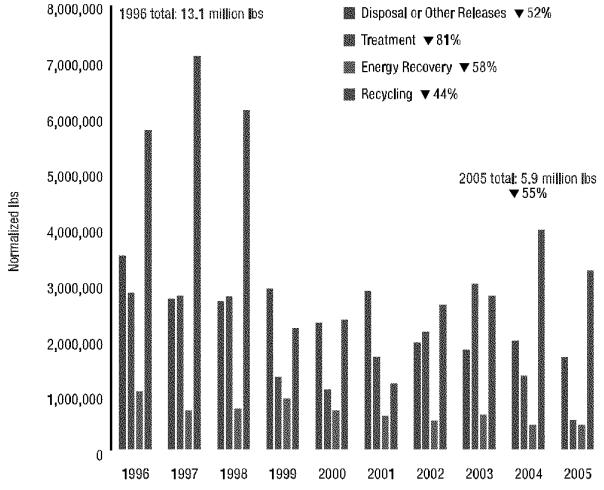
PAINT & COATINGS



OIL & GAS (PETROLEUM REFINING)



SHIPBUILDING & REPAIR



FOr SectOr-SpeciFic WaSte ManageMent chartS

Notes:

1. Normalized by annual value of shipments or production. Oil & gas lbs. normalized by annual crude oil input into refineries.
2. Disposal and Other Releases includes air emissions, water discharges, and land disposals.
3. The apparent spike in treatment for Chemical Manufacturing in 2000 was due to the report filed by a single facility.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce, U.S. Geological Survey, American Foundry Society, and U.S. Department of Energy

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This report relies upon a variety of public and private data sources to provide a comprehensive account of the sectors' environmental performance between 1996 and 2005. This chapter presents an overview and basic discussion of these data sources and explains figures used in the sector chapters. The Data Sources, Methodologies, and Considerations chapter at the end of this report provides a comprehensive discussion of the sources, methodologies, and considerations concerning the data.

Sector Profile

For generating most of the data used in this report, each sector is defined by a North American Industry Classification System (NAICS) code or group of codes.[1] NAICS replaced the U.S. Standard Industrial Classification (SIC) system in 1997. Because some of the data sources used in this report use SIC codes, at least for historical data, Table 1 below shows both the NAICS and SIC definitions for each sector. Note that some sectors are defined by a specific list of facilities, rather than by these classification codes, because the codes encompass a broader range of operations.

Data GUIDe

tABLe 1
Definition of Sectors

Sector	NAICS Code or Alternative	SIC Code
Cement	List of facilities from Portland Cement Association's Plant Information Summary directory	
Chemical Manufacturing	325	28
Specialty-Batch Chemicals	*List of facilities from the Synthetic Organic Chemical Manufacturers Association*	
Colleges & Universities	61131	8221
Construction	236, 237, 238	15, 16, 17
Food & Beverage Manufacturing	311, 3121	20, 5461
Forest Products		
Wood Products	*3211, 3212, 32191, 32192, 321999*	*242, 243, 244, 249*
Paper Products	*3221, 32221, 322221-322224, 322226, 32223, 32229*	*26*
Iron & Steel	List of integrated and mini mills from EPA's Sector Strategies Division	
Metal Casting	33151, 33152	332, 336
Oil & Gas		
Extraction	*211, 213111, 213112*	*13*
Petroleum Refining	*32411*	*2911*
Paint & Coatings	32551	2851
Ports	48831, 48832	4491
Shipbuilding & Ship Repair	336611	3731

Normalization of Absolute Releases

Where the report presents data showing trends over time, data are often adjusted to account for changes in sector production or output over the same period, also referred to in this report as "normalizing."

Normalizing means adjusting the absolute annual emissions values to account for changes in sector production or output over the same period. Normalizing removes the impact of growing or shrinking economic trends in industry, so that environmental changes occurring for other reasons can be seen more clearly. For example, if absolute emissions steadily decline over time, this could be caused by declining production in the sector, rather than any real improvement in day-to-day environmental performance.

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tABLe 2

Economic Activity and Normalization Factors for TRI Data

Sector	Normalizing and Sector Output Metric	Normalizing and Sector Output Data Source
Chemical Manufacturing Food & Beverage Manufacturing Forest Products Paint & Coatings Shipbuilding & Ship Repair	Value of shipments ($, adjusted for inflation)	U.S. Department of Commerce (DOC), Bureau of Economic Analysis (BEA): Industry Economic Accounts, 2005, http://www.bea.gov/industry/xls/GDPbyInd_SHIP_NAICS_1998-2005.xls
	Inflation adjustment for value of shipments	U.S. Department of Commerce (DOC), Bureau of Economic Analysis (BEA), National Economic Accounts, Current-Dollar and "Real" Gross Domestic Product, http://bea.gov/national/xls/gdplev.xls
Cement Manufacturing	Production of Clinker (millions of metric tons)	U.S. Geological Survey's (USGS) Cement Statistics and Information: Mineral Commodity Summaries 1997-2007, http://minerals.usgs.gov/minerals/pubs/commodity/cement/index.html
Iron & Steel	Steel Production, basic oxygen and electric arc furnaces (thousands of metric tons)	U.S. Geological Survey's (USGS) Iron and Steel Statistics and Information: Mineral Commodity Summaries 1997-2007, http://minerals.usgs.gov/minerals/pubs/commodity//iron_&_steel/index.html
Metal Casting	Ferrous & Non-Ferrous Shipments (millions of tons)	American Foundry Society (AFS)
Oil & Gas (Petroleum Refining)	Crude Oil Inputs into Refineries (thousand barrels/year)	U.S. Department of Energy (DOE), Energy Information Administration (EIA), Petroleum Refining & Processing, Weekly Inputs, Utilization & Production, http://tonto.eia.doe.gov/dnav/pet/pet_pnp_wiup_dcu_nus_w.htm

The metrics used to normalize data vary across the sectors but are identified for each graphic or chart. When available, production data (e.g., tons of product produced annually by the sector) was the preferred metric for normalizing. When production data were not available for the full time frame required, value of shipments was used instead.

Economic and Geographic Information

Name: County Business Patterns

Source: U.S. Census Bureau

Metrics: Number of employees and number of establishments

Frequency: Annual

Period Analyzed: 2005

Next Data Release: 2006 data expected mid-year 2008

Website: http://www.census.gov/epcd/cbp

The employment and number of establishments data presented in the "At-a-Glance" section of each sector chapter are from the U.S. Census Bureau, County Business Patterns (CBP). CBP is an annual series published by the U.S. Census Bureau that provides economic data by industry and covers most of the country's economic activity.

When production data are not available, this report shows output using value of shipments (VOS). For some sectors, we include information more suitable than VOS to convey economic activity, as shown in Tables 2 and 3. Sector "At-a-Glance" sections showing VOS trends present current dollars for each of the years represented. In constant dollars (with a 1996 baseline), the 2005 figures would be approximately 17% lower than they appear when using current dollars.

A U.S. map is presented for each sector showing the locations of facilities within that sector. The portrayals of Alaska, Hawaii, and Puerto Rico are not drawn to scale and do not represent their respective locations relative to the contiguous states.

Note that the facility counts for many sectors under "At-a-Glance" rely upon CBP data. Ideally, both the maps and facility counts would come from a single source, but CBP does not include establishment-level data or location information. Instead, facility location information is sepa-

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tABLe 3

Economic Activity Data for Sectors Without TRI Data

Sector	Sector Output Value	Sector Output Data Source
Colleges & Universities	Revenue (millions of $, adjusted for inflation)	National Center for Educational Statistics: Digest of Education Statistics, http://nces.ed.gov/programs/digest/
Construction	Value of Construction Put in Place (millions of $, adjusted for inflation)	U.S. Census Bureau, Current Construction Reports, http://www.census.gov/const/www/c30index.html
Oil & Gas (Exploration & Production)	Crude Oil Field and Natural Gas Production (billion Btu)	U.S. Department of Energy (DOE), Energy Information Administration (EIA), Production in Btu derived from Crude Oil Field Production (Barrels) and Natural Gas Gross Withdrawals and Production (MMcf), http://tonto.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm; http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm
Ports	Revenue (millions of $, adjusted for inflation)	U.S. Census Bureau, Economic Census: Transportation and Warehousing, Support Activities for Transportation, http://www.census.gov/econ/census02/

rately sourced for each sector in the individual chapters. Therefore, the number of facilities mapped will not equal the number of facilities cited as the sector universe.

Energy Use

The "Energy Use" sections in the sector chapters discuss energy consumption. A key source of information is the Manufacturing Energy Consumption Survey (MECS).

The DOE's EIA collects data on the energy consumption of U.S. manufacturers. Every four years, EIA mails a detailed questionnaire to a statistically valid sample of firms. EIA then extrapolates sample data to produce sector-level energy consumption estimates.

Name: Manufacturing Energy Consumption Survey

Source: Energy Information Administration

Metric: energy consumption by manufacturers

Frequency: quadrennial

Period Analyzed: 2002

Next Data Release: 2006 MECS expected in late 2008

Website: http://www.eia.doe.gov/emeu/mecs

Sectors Covered: Cement Manufacturing, Chemical Manufacturing, Food & Beverage Manufacturing, Forest Products, Iron & Steel, Metal Casting, and Oil & Gas

Context Beyond This Report

Where we can, we provide some perspective on the 12 sectors covered in this report by giving examples of their impact, both individually and collectively, in the national and global environment and economy. There are many different sources of data (such as federal and state governments, universities, businesses and business groups, non-governmental organizations) and many ways to analyze data. Each method can provide unique insight for understanding and influencing environmental performance. Data allowing consideration and action by sector are most readily available for industrial sectors.

This focus on a "sector" report necessarily circumscribes the types, amount, and comprehensiveness of data used. We do not, for instance, discuss releases from motor vehicles, from sources of pesticides or fertilizers, or from many other non-industrial sources. Benzene, for example, is a known human carcinogen that is reported by most of our industry sectors, yet the combined releases from these sectors is far outweighed by reported emissions from burning coal and oil, motor vehicle exhaust, and evaporation from gasoline service stations. Tobacco smoke contains benzene and accounts for nearly half of the national exposure to benzene.[2] Having said this, the value of the analysis compiled in this report, from an industrial sector perspective, is significant. It provides, for example, a multi-media look at current environmental data that both educates the sectors on specific details and trends of their environmental "footprint," and it opens the door for opportunities to reduce those footprints through source reduction or chemical substitution.

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Ultimately, efforts to report, analyze, and control chemical releases stem from the recognition that they pose some degree of "risk" to human health and the environment. Determining that potential risk depends on many factors, including a determination of the toxicity of the chemical, its fate after its release to the environment, the location of the release, and the populations exposed to the chemical. There are many ongoing and complex efforts to identify this risk by this Agency and other institutions that include reviewing inventories of toxic chemical releases and the sources that emit them. That level of risk screening and analysis, even just from an industrial sector perspective, is beyond the scope of this report. What we have chosen to do, through the "Toxicity Score" table presented in most sector chapters, is not meant to be an oversimplification of risk methodologies. The Toxicity Score tables are yet another way for a sector to identify chemicals of concern and potentially prioritize opportunities for source reduction or chemical substitution. We hope that this presentation will both highlight topics to consider for action and encourage discussion of the strengths and weaknesses of this approach.

Air Emissions

The sections on "Air Emissions" include information on air emissions of chemicals reported to the Toxics Release Inventory (TRI), criteria air pollutants (CAPs), and for some sectors, greenhouse gases (GHGs). The sections rely primarily on TRI, the National Emissions Inventory (NEI), and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*. An overview of these sources is given below, as well as a discussion of the model EPA uses to analyze the toxicity of air emissions, the Risk-Screening Environmental Indicators (RSEI) model.

Toxic Releases

This report presents aggregated air emissions of TRI chemicals by the reporting facilities in each sector from 1996 through 2005 (the most current data available at the time the analyses were conducted for this report). TRI is a publicly available database containing information on the release and management of more than 600 chemicals and chemical categories by facilities that use, process, or manufacture these chemicals at annual levels above reporting thresholds. TRI is based on reports filed by the facilities. TRI contains information on toxic chemicals that facilities emit or otherwise manage as waste, including hazardous air pollutants (HAPs), which are also referred to as "air toxics." HAPs are air pollutants that pose a direct threat to human health.

Name: Toxics Release Inventory

Source: EPA

Metrics: Estimated releases, transfers, and disposals

Frequency: Annual

Period Analyzed: 1996–2005

Latest Data Release: February 2008 for 2006 Public Data Release

Website: http://www.epa.gov/tri

Sectors covered: Cement Manufacturing, Chemical Manufacturing, Food & Beverage Manufacturing, Forest Products, Iron & Steel, Metal Casting, Paint & Coatings, Oil & Gas (Petroleum Refining), and Shipbuilding & Ship Repair

Considering the Toxicity of Air Emissions

This report includes discussions of the toxicity of air releases. The toxicity of TRI chemicals—meaning how harmful they can be to human health—varies greatly.

RSEI assigns each TRI chemical, to the extent data are available, two chemical-specific relative toxicity weights: one for inhalation of the chemical, and one for ingestion of the chemical. These relative toxicity weights provide a method to score the potential harm of chemicals relative to each other. Toxicity weights for chemicals increase as the toxicological potential to cause chronic human health effects increases. For example, pound for pound mercury has a higher relative toxicity weight than a pound of methanol. Risk posed by a chemical to an individual is a function of many variables such as the route and duration of exposure, the extent of the chemical's absorption into the individual, and the chemical's intrinsic toxicity. The RSEI model is not designed to address these variables. Hence, the model expresses risk in terms of relative risk or relative Toxicity Scores, not actual risk posed by releases of a specific chemical or chemicals to individuals. The results of RSEI analyses are only meaningful when compared to other results produced by the model. To consider toxicity, EPA's RSEI model multiplies the quantity of media-specific TRI releases (e.g., pounds of mercury released to air) by the chemical-specific relative toxicity weights to calculate a relative Toxicity Score. Because of data limitations, this report presents RSEI information only for air emissions reported to TRI.

Refer to the Data Sources, Methodologies, and Considerations chapter for additional information.

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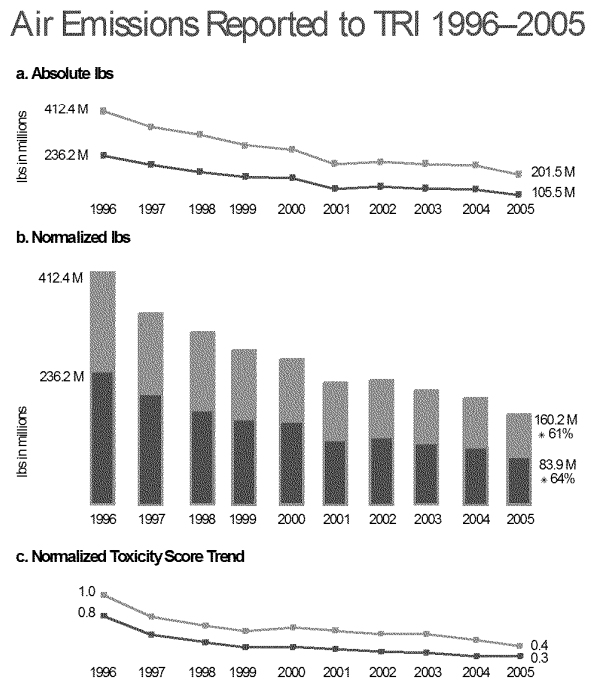
Presentation of TRI Air Emissions Data

As shown in the sample figure below, the TRI air emissions data discussion presents three related trends that provide a progressively focused look at the sector's toxic chemical emissions.



Section A of the figure presents the sector's TRI-reported absolute pounds of toxic chemical and HAP air emissions from 1996 to 2005. The sets of lines share the same horizontal axis, representing years, with the bars. The top, red line in the "Absolute lbs" set presents the trend for "All TRI Chemicals, including HAPs." The lower, blue line presents the trend for TRI HAP emissions only; TRI HAPs are a subset of "All TRI Chemicals." The sample graph shows that this sector released 412 million lbs. of TRI chemicals to the air in 1996, 236 million lbs. of which were HAPs. By 2005, total TRI emissions declined to 201 million lbs.

Section B of the figure presents the sector's toxic chemical and HAP emissions normalized by the sector's VOS over the same period. The overall percent changes of normalized emissions of all TRI chemicals and of just HAPs are presented beside an arrow (indicating an increase or decrease) to the right of these bars. The sample graph shows that the sector's air emissions of TRI chemicals, normalized by VOS, decreased by 61% from 1996 to 2005. Over this same period, the sector's normalized HAP emissions decreased by 64%.

Section C of the figure shows the relative Toxicity Score of the TRI chemicals and HAPs emitted to the air by the sector. The figure uses 1996 as a baseline for the relative Toxicity Score, assigned a ratio of one. Change in toxicity is calculated relative to that 1996 total value; a 60% decrease in relative Toxicity Score resulted in a 2005 relative Toxicity Score of 0.4, as seen in the example graph above. The normalized toxicity-weighted results for HAP emissions accounted for approximately 80% of the relative Toxicity Score in 1996, as indicated by the 0.8 value on the left side of the graph. The relative Toxicity Score for HAPs showed a declining trend similar to that for all TRI emissions, with a reduction from 0.8 to 0.3, a 62.5% decline

Chapters presenting TRI data include a table titled, "Top TRI Air Emissions," which identifies the top five TRI chemicals released to air in 2005 for each of three categories: the absolute quantity (in pounds) emitted, the chemicals' relative Toxicity Score, and the number of facilities reporting each chemical. The five red numbers in each category indicate the top five chemicals for that indicator. The chemicals in italics are HAPs.

In the sample table below, for example:

- Ammonia, hydrochloric acid, methanol, n-hexane, and nitrate compounds were the five chemicals reported in the largest quantity in this sector, and are shown in red in the "Absolute Pounds Reported" column. The "Percentage of Sector Total" in the "Absolute Pounds Reported" column shows that the chemicals included in this table accounted for 95% of the sector's TRI air emissions.
- Acetaldehyde, acrolein, hydrochloric acid, polycyclic aromatic compounds, and sulfuric acid were the five chemicals with the highest relative Toxicity Score reported in this sector, and are shown in red in the "Percentage of Toxicity Score" column. The "Percentage of Sector Total" in the "Percentage of Toxicity Score" column means that the chemicals included in this table accounted for 86% of the sector's relative Toxicity Score for TRI air emissions.
- Ammonia, n-hexane, lead, polycyclic aromatic compounds, and zinc were the five chemicals reported by the most facilities in this sector, and are shown in red in the "Number of Facilities Reporting" column. The "Percentage of Sector Total" in the "Number of Facilities Reporting" column means 51% of TRI reporters in the sector reported one or more of the chemicals in this table.

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported	Percentage of Toxicity Score	Number of Facilities Reporting
Acetaldehyde	2,048,000	5%	24
Acrolein	24,000	25%	2
Ammonia	11,956,000	2%	408
Hydrochloric Acid	4,224,000	4%	34
Lead	17,000	2%	68
Methanol	3,002,000	<1%	38
N-Hexane	22,027,000	1%	86
Nitrate Compounds	2,637,000	<1%	14
Polycyclic Aromatic Compounds	59,000	10%	48
Sulfuric Acid	1,774,000	37%	22
Zinc	15,000	<1%	43
Percentage of Sector Total	**95%**	**86%**	**51%**

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Criteria Air Pollutants

Name: National Emissions Inventory

Source: EPA

Metrics: Emission estimates for SO_X, NO_X, PM (<10 microns and <2.5 microns), CO, and VOCs

Frequency: Every 3 years

Period Analyzed: 2002

Next Data Release: 2005 NEI for point sources in Spring 2008

Website: http://www.epa.gov/ttn/chief/trends/

Sectors covered: Cement Manufacturing, Chemical Manufacturing, Colleges & Universities, Food & Beverage Manufacturing, Forest Products, Iron & Steel, Metal Casting, Paint & Coatings, Oil & Gas, and Shipbuilding & Ship Repair

NEI, a publicly available EPA database, contains information on emissions of CAPs and HAPs. The Clean Air Act regulates six CAPs, including particulate matter (both coarse, PM_{10}, and fine, $PM_{2.5}$, which is included in PM_{10}), ground-level ozone (O_3), carbon monoxide (CO), sulfur oxides (SO_X), nitrogen oxides (NO_X), and lead (Pb). Lead, also defined as a HAP, is discussed in this report as a HAP. Volatile organic compounds (VOCs) are not CAPs, but in the presence of sunlight they react with NO_X to create O_3.

The emissions data in NEI are compiled every three years. There is no threshold amount for NEI reporting, so all point sources should be captured in the database. This report describes CAP and VOC emissions for 2002 (the most current year of data available during the analyses for this report), as shown in the sector chapters, including their latest environmental statistics.

Greenhouse Gases

Name: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005

Source: EPA

Metrics: Emission estimates for CO_2, CH_4, N_2O, and fluorinated gases

Frequency: Annual

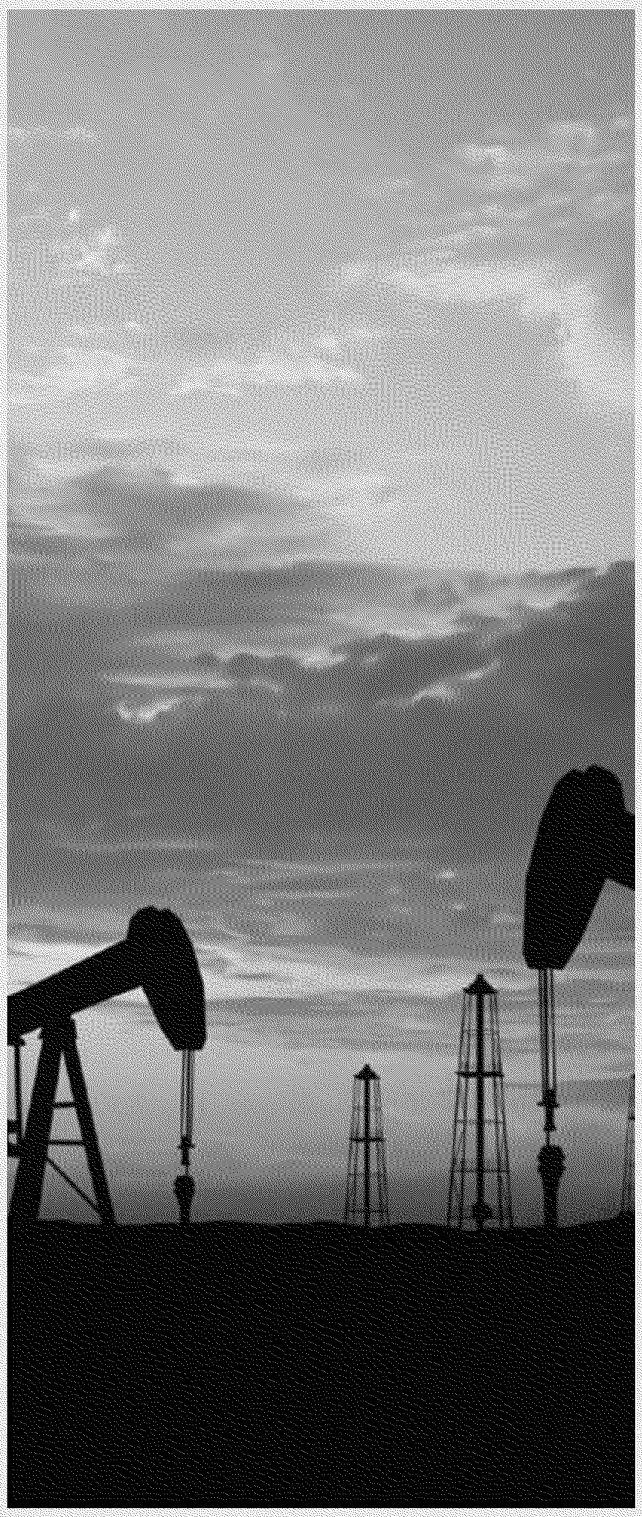
Period Analyzed: 2005

Most Recent Data Release: April 2008

Next Data Release: April 2009

Website: http://www.epa.gov/climatechange/emissions/usgginventory.html

GHG emissions are discussed for certain sectors, for which data were available from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* and other sources. GHGs include, but are not limited to, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases.



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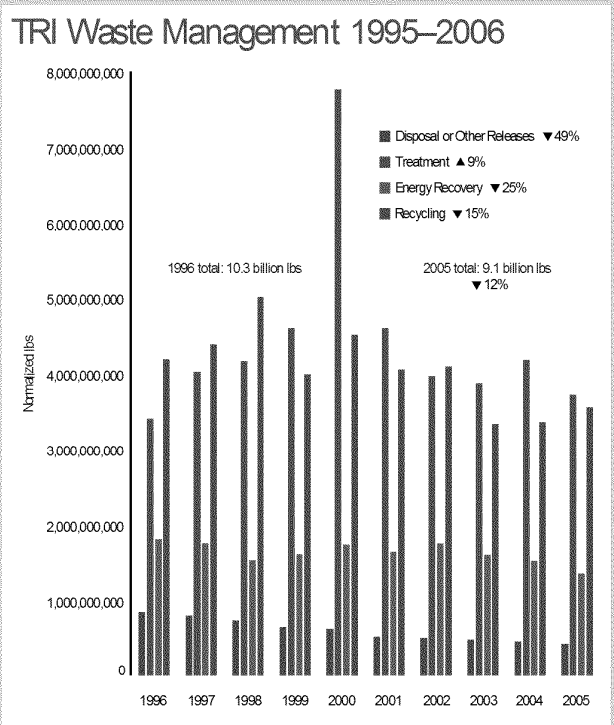
Presentation of TRI Waste Management Data

As shown in the sample figure below, the TRI data discussion in this section presents trends showing the management of toxic chemicals from 1996-2005. In this sample, the sector managed 10.3 billion lbs. of TRI chemicals in 1996. The percentages show the percent change of quantities of waste managed by each method over the 10-year period, normalized by VOS. For example, TRI chemicals recycled and used for energy recovery by the sector decreased by 15% and 25%, respectively.

The table titled "Top TRI Disposals" identifies the top TRI chemicals disposed in 2005, based on absolute pounds and the number of reporting facilities. The five red numbers in each category indicate the top five chemicals for that indicator.

In the sample table, for example:

- Nitrate compounds, barium, ammonia, zinc, and manganese were the five chemicals reported as disposed in the largest quantities, and are shown in red in the "Absolute Pounds Reported" column. The "Percentage of Sector Total" in the "Absolute Pounds Reported" column shows that the chemicals included in this table accounted for 93% of the sector's TRI disposals.
- Ammonia, lead, nitrate compounds, nitric acid, and zinc were the five chemicals disposed by the largest number of facilities reporting, and are shown in red in the "Number of Facilities Reporting" column. The "Percentage of Sector Total" in the "Number of Facilities Reporting" column shows that 26% of TRI reporters in the sector reported one or more of the chemicals in this table.



Top TRI Disposals 2005

Chemical	Absolute Pounds Reported	Number of Facilities Reporting
Ammonia	1,350,000	136
Barium	1,697,000	16
Lead	92,000	37
Manganese	519,000	19
Nitrate Compounds	13,869,000	154
Nitric Acid	369,000	29
Zinc	690,000	36
Percentage of Sector Total	**93%**	**26%**

Water Use and Discharges

The "Water Use and Discharges" sections present information on TRI chemicals discharged to water and additional data from other sources for sectors where available. While TRI chemicals are not generally the most significant factors influencing water quality, data on water discharges of other pollutants are not adequately refined to allow meaningful sector-based analyses.

Waste Generation and Management

The "Waste Management" sections of this report include information on hazardous wastes and on TRI chemicals managed as waste. EPA emphasizes reducing waste generation whenever possible and, if waste is generated, minimizing the quantity that is released or disposed, by instead increasing recycling, energy recovery, or treatment. This report presents waste management information as categorized by TRI, into recycling, energy recovery, treatment, and disposal or other releases.

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Hazardous Waste

Pursuant to the Resource Conservation and Recovery Act (RCRA), EPA biennially collects information on the generation, management, and final disposition of hazardous waste from large quantity generators (LQGs) and treatment, storage, and disposal facilities (TSDFs), and compiles a National Biennial RCRA Hazardous Waste Report (BR). Any facility that meets the criteria to be considered an LQG or TSDF is required to report. Unlike TRI, there is no restriction based on the industrial sector (e.g., no NAICS code criteria). Also, unlike TRI, BR reflects the weight of entire waste streams, rather than just the weight of particular toxic chemicals within those streams.

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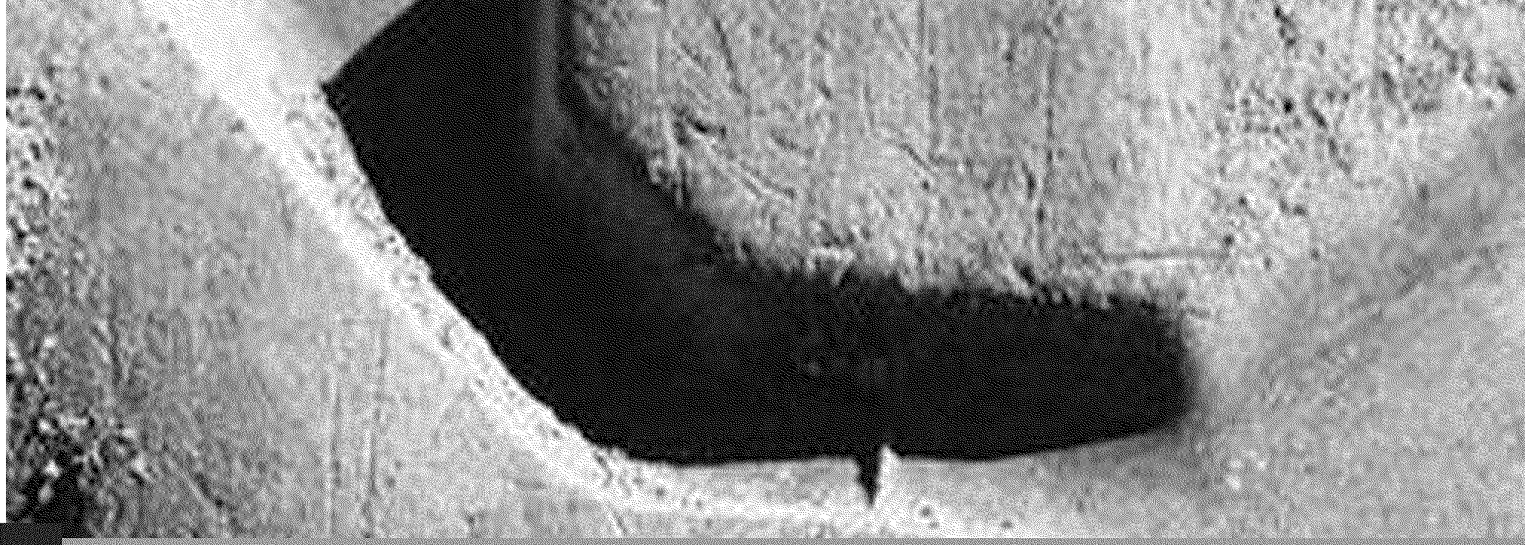
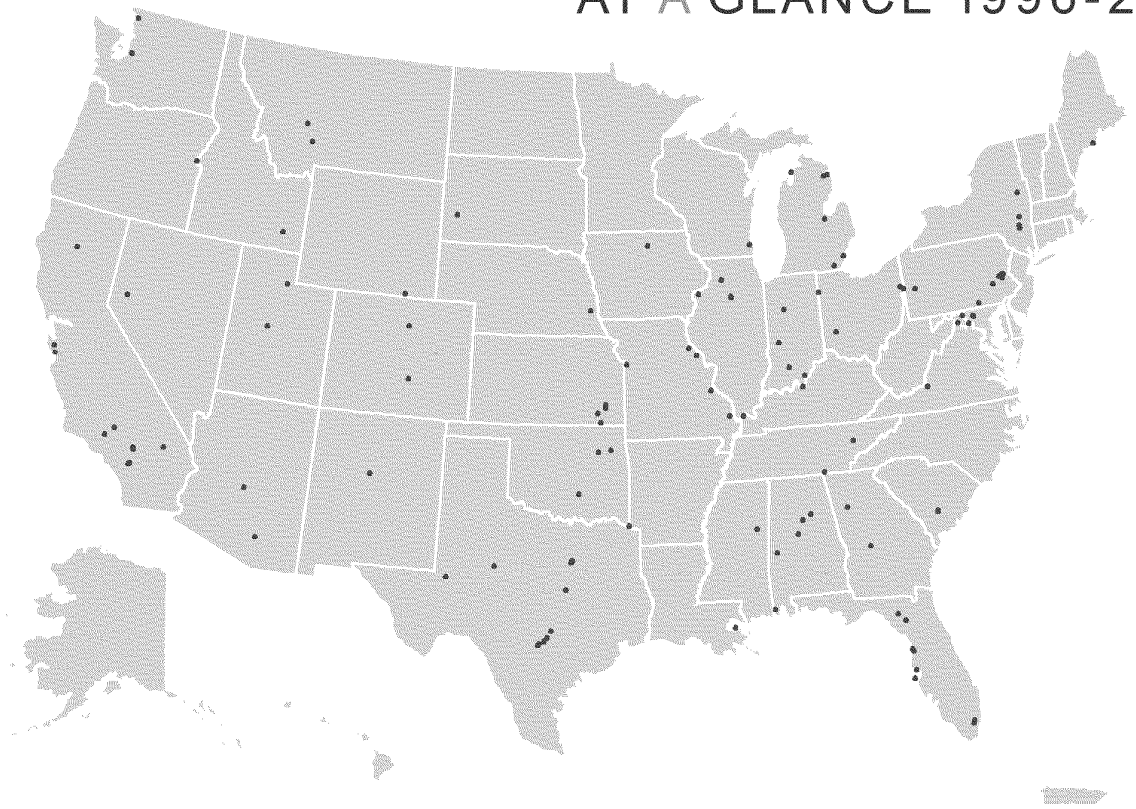


Cement manufaCturing

AT A GLANCE 1996-2005[1]



115 facilities — 115 ▲ 0%

13,800 employees — 13,800 ▲ 0%

70.4 million metric tons of clinker produced — 87.4 million ▲ 24%

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Latest Environmental Statistics[2]

Energy Use: 410.8 trillion Btu

Emissions of Criteria Air Pollutants: 576,000 tons

Releases of Chemicals Reported to TRI: 13.5 million lbs.

air emissions: 10.6 million lbs.

Water Discharges: 3,300 lbs.

Waste Disposals: 2.9 million lbs.

Recycling, Energy Recovery, or Treatment: 412 million lbs.

Hazardous Waste Generated: 17,000 tons

Hazardous Waste Managed: 31,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Cement Manufacturing sector produces Portland cement, a binding agent that when mixed with water, sand, and gravel or crushed stone forms the rock-like mass known as concrete. Concrete, in turn, serves highway, commercial, and residential construction projects.

Limestone is the key ingredient to manufacture cement. Limestone and other ingredients, including material that is aluminous, ferrous, and siliceous, are placed into a kiln where a thermochemical process occurs to make cement clinker. The cement clinker is mixed with additives (e.g., gypsum) to make Portland cement.

The U.S. Cement Manufacturing sector is concentrated among a relatively small number of companies; many U.S. cement plants are owned by or are subsidiaries of foreign companies. Together, 10 companies accounted for about 80% of total U.S. cement production in 2005.[3]

California, Texas, Pennsylvania, Florida, and Alabama are the five leading cement-producing states and accounted for about 48% of recent U.S. production.[4]

Although production, imports, sales volumes, and prices of cement all reached record high levels in 2005, cement consumption is expected to decline in the near future.[5]

Energy Use

Cement Manufacturing is an energy-intensive industry. The thermochemical production process requires very high temperatures; grinding and crushing operations also use energy. On average, producing one metric ton of cement requires 4.7 million Btu.[6] Between 2000 and 2006, the sector's energy consumption, when normalized by clinker production, decreased about 7%.[7]

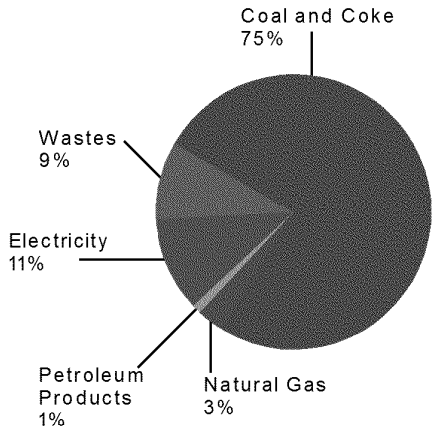
To make cement, the manufacturer places limestone and other ingredients into the upper end of a rotary kiln. At the lower end of the inclined kiln, a burner pipe emits a large flame, providing the intense heat required for the thermochemical process. The limestone and other materials go through several chemical processes that require temperatures reaching almost 1,500 degrees Centigrade (C). During the process, the raw materials, fuel molecules, and the air inside the kiln break apart. The limestone becomes calcium oxide and carbon dioxide (CO_2). Calcium oxide and silicates bond to form the principal compounds that cool into solid pellets called clinker. The manufacturer grinds clinker with gypsum and smaller amounts of other ingredients to create Portland cement.

Kilns employ either a wet or dry process. The wet process uses raw materials ground with water to create a slurry material to be fed into the kiln, while the dry process uses dry materials in a powder-like input to the kiln. The wet process was initially used to improve the chemical uniformity of raw materials being processed; however, it

Figure 1

Fuel Use for Energy 2006

Total: 410.8 trillion Btu



Source: Portland Cement Association

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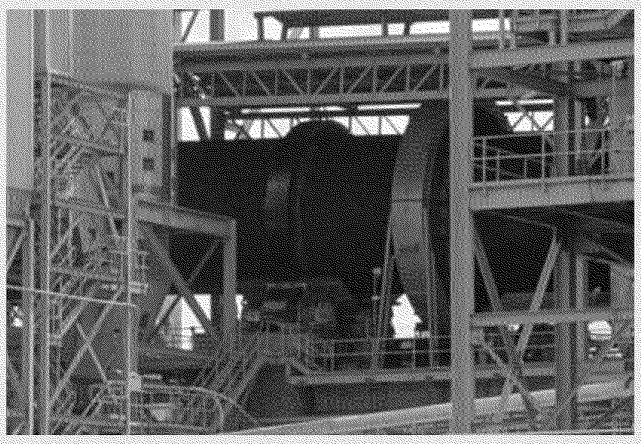

requires 32% more energy per ton of clinker production than the average for dry processes.[8] Technological improvements have allowed cement makers to utilize the dry process without quality deficiencies, and no new wet kilns have been built in the United States since 1975.[9] Some existing plants are switching from the wet to the dry process.[10] About 85% of U.S. cement production capacity now relies on the dry process technology.[11]

As shown in Figure 1, Cement makers are able to utilize a variety of fuels to maintain high temperatures within kilns, such as coal, petroleum coke, distillate and residual fuel oils, natural gas, used tires, and solid and liquid wastes. The significant quantity of fuel and raw materials needed to manufacture cement provides an opportunity for the sector to consume alternative fuels and raw materials generated as byproducts from other industries.

Many plants meet 20–70% of their energy requirements with alternative fuels.[12] These fuels include scrap tires, waste oil, refinery wastes, and other solid and liquid wastes that have fuel value. Cement kilns burn hotter, have longer gas residence times, and are much larger than most commercial thermal treatment facilities (e.g., hazardous waste incinerators), making them ideal for reclaiming such materials when properly managed.

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). CAPs and GHGs also are generated as byproducts from onsite combustion of fuels in cement kilns.

Air emissions from the kiln system are the primary environmental concern in cement manufacturing. More than 99% of the exit gases are composed of nitrogen, water vapor, and CO_2, while less than 1% is nitrogen oxide (NO_X), sulfur dioxide (SO_2), and even smaller quantities of organic compounds and heavy metals.[13]

The major processes in making Portland cement that cause air emissions are fuel combustion, the thermochemical process of making clinker, and crushing and grinding operations. The intense heat of the combustion process separates the fuel into organic and inorganic components. The organic components are consumed as fuel, while the various inorganic components become either part of the cement product or are collected in a plant's air pollution control device (e.g., electrostatic precipitator or baghouse).

Raw materials, particularly clay, may contain ammonia, which is partially roasted off during material preheating. Smaller amounts may come from loss of ammonia when used in selective non-catalytic reduction (SNCR) NO_X control devices. Benzene and ethylene are found in both conventional and alternative raw materials and are partially roasted off during material preheating.

Chlorine may be present in raw materials as well as in alternative fuels (e.g., spent solvents, plastics). Much of the chlorine becomes bound in the clinker. Emissions can result if inputs exceed the capacity of the clinker to absorb inbound chlorine, in which case the chlorine combines with hydrogen to produce hydrochloric acid.

Metals are found in all cement input materials, including limestone, clay, coal, and cement kiln dust (CKD). Semi-volatile and volatile metals evaporate and condense on the fine dust fraction of material recovered in air pollution control equipment. Reduction controls for most heavy metals include efficient dedusting equipment (baghouses and electrostatic precipitators) and limits to inputs in feed materials (currently the primary control method for mercury).

Air Emissions Reported to TRI

In 2005, 109 facilities in the sector reported 10.6 million absolute lbs. of air emissions to EPA's TRI.[14] The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. The absolute pounds emitted annually increased nearly 19% from 1996 to 2005, as shown in Figure 2a, but when normalized by annual clinker production, the sector's TRI air emissions decreased by 4% over the same period, as shown in Figure 2b.[15]

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

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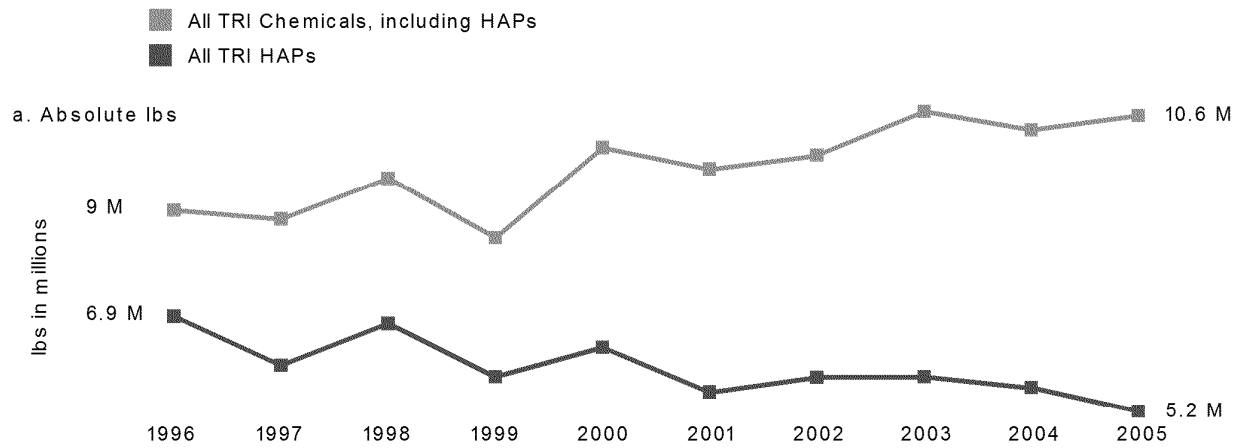
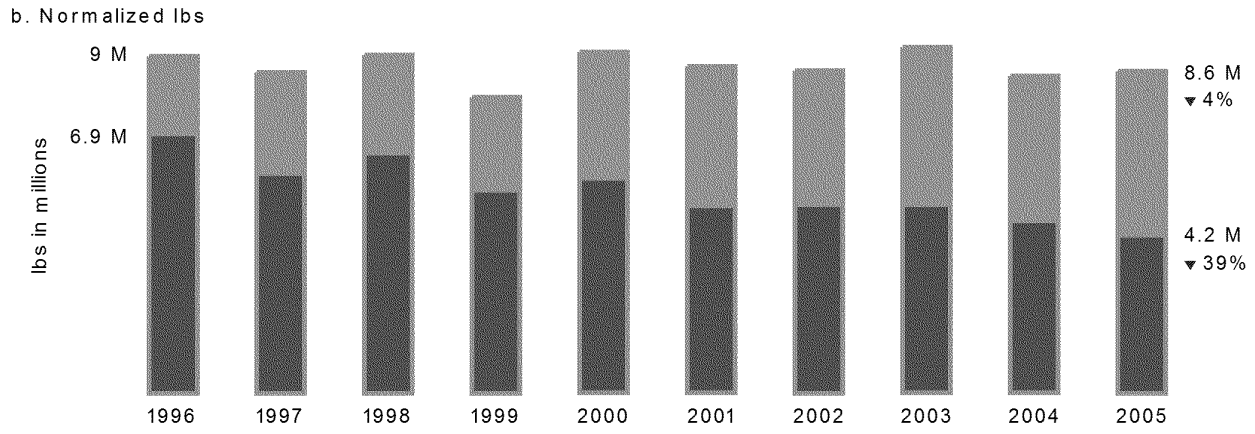
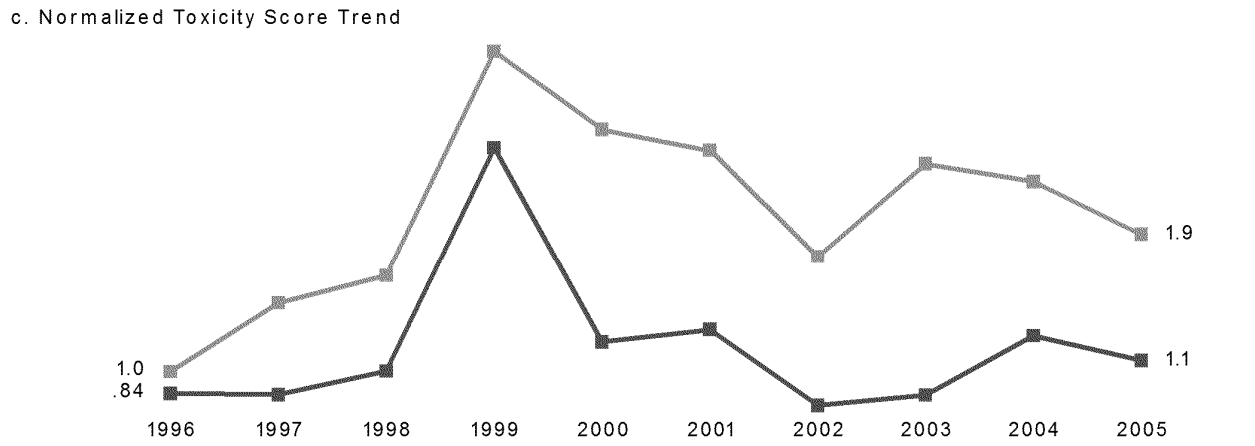
Figure 2

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual clinker production.

Sources: U.S. Environmental Protection Agency, U.S. Geological Survey

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Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. The sector's Toxicity Scores fluctuated from 1996 to 2005, with an overall increase of 98%, when normalized by clinker production. Fluctuations in emissions of sulfuric acid and chromium caused reciprocal fluctuations in the sector's overall Toxicity Score. Fluctuations in sulfuric acid, which is released as a byproduct from burning coal during clinker manufacturing, were driven by changes in pounds reported by only a few cement plants. Changes in chromium results were due to naturally occurring variations in the level of chromium in limestone.[16] The apparent spike in 1999 was due, among other things, to changes in methodologies used to calculate releases, and to changes in TRI reporting requirements. In absolute pounds, HAPs accounted for 49% of the sector's air emissions reported to TRI in 2005, and 54% of the overall Toxicity Score.

Table 1 presents the sector's top TRI-reported air emissions based on three indicators.

Table 1

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Ammonia	1,469,000[3]	<1%	15
Benzene[4]	599,000	1%	14
Chlorine	50,000	7%	1
Chromium	10,000	14%[5]	63
Dioxin and Dioxin-Like Compounds	<1	<1%	74
Ethylene	1,811,000	<1%	1
Hydrochloric Acid	3,900,000	6%	35
Lead	15,000	2%	107
Manganese	34,000	19%	34
Mercury	11,000	1%	104
Sulfuric Acid	1,580,000	45%	11
Percentage of Sector Total	**89%**[6]	**95%**[7]	**100%**[8]

Notes:
1. Total sector air releases: 10.6 million lbs.
2. 109 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
5. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
6. Chemicals in this list represent 89% of the sector's air emissions.
7. Chemicals in this list represent 95% of the sector's Toxicity Score.
8. 100% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

1) Absolute Pounds Reported. Hydrochloric acid and ethylene were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005, although ethylene was largely reported by a single facility.
2) Percentage of Toxicity Score. Sulfuric acid and metals—manganese and chromium—dominated top chemicals based on Toxicity Score. Manganese and other metals can occur naturally in limestone.
3) Number of Facilities Reporting. Lead and mercury were the most frequently reported chemicals, with almost all of the TRI filers in the sector reporting these chemical emissions.

Criteria Air Pollutants

At 219,000 tons in 2002, NO_X were the largest CAP emissions from cement making, as shown in Table 2.[17] NO_X formation is an inevitable consequence of high temperature combustion. Called "Thermal NO_X," it is produced in the main flame of all cement kilns and is formed during combustion of air. Some NO_X may result from combustion of fuels.[18] Control strategies include low-NO_X burners and SNCR technologies.

Table 2

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	161,000
NO_X	219,000
PM_{10}	37,000
$PM_{2.5}$	17,000
CO	150,000
VOCs	9,000

Notes:
1. PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

SO_2 results from volatilization of sulfur from raw materials roasted off during material preheating. The range of emissions depends on the content of volatile sulfur compounds in the raw materials. Control strategies include the addition of hydrated lime to the kiln feed and the use of wet sulfur scrubbers. Volatile organic compounds (VOCs) result from volatilization of organics in raw materials (limestone and shale) that are roasted off at material preheating. The range of emissions depends upon the content of the raw materials mined. Carbon monoxide (CO) is formed either because of incomplete combustion or the rapid cooling of combustion products below the ignition temperature of 610°C.

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At the end of the thermal treatment process, gases and pulverized materials must be separated again. Incomplete separation gives rise to dust emissions from the kiln/raw mill main stack, the clinker cooler stack, cement mill stacks, or material transfer point dedusting air outlets. Bag filters and electrostatic precipitators are emission reduction techniques typically used.

The fine dust generated from the kiln line, collectively labeled cement kiln dust, includes particulates representing the raw mix at various stages of burning, particles of clinker, and even particles from the eroded refractory brick linings of the kiln tube. Most U.S. plants have reduced CKD air emissions to small amounts by using dust scrubbers—either electrostatic precipitators or filtration baghouses.

In general, the introduction of newer kiln technology and improved process controls by the sector has led to overall reductions of CAP emissions. Process controls stabilize kiln operations by improving energy efficiency, reducing heat consumption, improving clinker quality, and reducing emissions.

Greenhouse Gases

Cement manufacturers directly emit GHGs from their consumption of raw materials and combustion of fuels. The chemical reaction creating cement emits large amounts of CO_2 as limestone breaks down into calcium oxide. Noncombustion cement production processes emitted 45.9 million metric tons of CO_2 equivalent in 2005.[19] The combustion of fuels in cement kilns and generation of electricity purchased by the sector also emit GHGs.

Figures published by major cement corporations provide some insight into the CO_2 emissions that cement companies have identified. Three reports from 2005 and 2006 from cement companies estimated CO_2 emissions in the range from 658 to 670 kilograms (kg) per metric ton of cement produced.[20]

The sector has various options for reducing GHG emissions, including using alternative sources of calcium oxide, such as steel slag, and upgrading to more efficient clinker production technologies, such as dry—rather than wet—process kilns. Under the U.S. Department of Energy's (DOE) voluntary Climate VISION program, the Portland Cement Association (PCA) adopted a voluntary goal to reduce CO_2 emissions by 10% per ton of cement product produced or sold by 2020, from a 1990 baseline.[23]

Reducing Greenhouse Gas Footprint

The California Portland Cement company signed a 25-year contract with a wind energy company that ensures a large portion of the power consumed at the plant located in Mojave, CA, will be renewable energy. This helped reduce the company's indirect GHG emissions in 2006 by 31,247 metric tons over 2005.[21]

Reducing Direct GHG Emissions

Buzzi Unicem's Signal Mountain plant in Chattanooga, TN, reduced its CO_2 emissions 51.3% after completing a $140 million upgrade to convert to a dry manufacturing process. The plant received a Green Industry Award from the Greater Chattanooga Chamber of Commerce.[22]

Water Use and Discharges

Cement plants generate little wastewater. The water used in wet process plants evaporates in the kiln. While 109 facilities reported air emissions to TRI in 2005, just 16 reported water discharges. These facilities reported 3,300 lbs. of TRI chemicals discharged to water.[24] There are currently no aggregate data available on the quantity of water used by the Cement Manufacturing sector.

Discharges to surface water also can result from stormwater runoff. Plant operators generally channel stormwater into holding ponds so the solid particles can be removed. Cement makers can discharge the water in compliance with permits or recycle the water to cool equipment.

Waste Generation and Management

Of the solid wastes generated in a kiln, CKD is a major issue. The tumbling and grinding of materials within a kiln produce a great deal of dust. CKD consists of the ash and other tiny particles remaining from the burnt limestone and other products. It can contain metals and materials remaining from the hazardous wastes sometimes used as supplemental fuel within a kiln. CKD is removed from the kiln exhaust gases by pollution-control devices such as baghouses and electrostatic precipitators.

CKD is a valuable commodity to the industry. Recycling CKD into the cement kiln offsets the use of limestone and other raw virgin materials and reduces fuel usage. More than 75% of CKD is now fed directly back into the kiln. When not recycled to the kiln, because of contaminant build-up and quality-control concerns (e.g., alkalis), CKD can sometimes be used as a soil conditioner (liming agent), as a somewhat cementitious material for roadfill, and occasionally as a filler or cementitious extender for finished cement.

As illustrated by Figure 3, the cement industry has used process improvements to reduce the amount of CKD disposed. PCA adopted a voluntary target for its member companies of a 60% reduction (from a 1990 baseline) of

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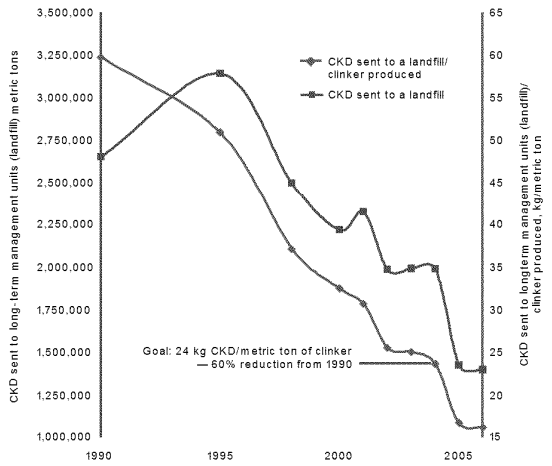
Figure 3

Cement Kiln Dust Disposal Rates With Reduction Goal



Source: Portland Cement Association

CKD disposed per ton of clinker produced—a goal of 24 kg CKD disposed of per metric ton of clinker produced. PCA members achieved this goal in 2004.[25]

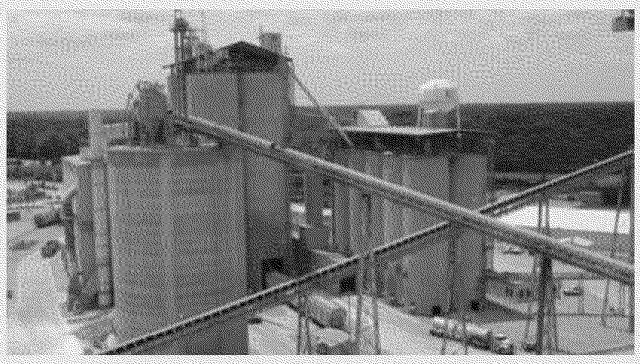
EPA has categorized CKD as a special waste temporarily exempted from federal hazardous waste regulations under the Resource Conservation and Recovery Act (RCRA). EPA is developing standards for management of CKD and has published a set of proposed Subtitle D (concerning nonhazardous solid waste) regulations to govern CKD management.

Alternative materials from other sectors can be used to make cement. These materials include byproducts from other industrial processes, such as used foundry sand from the Metal Casting sector, mill scale from the Iron & Steel sector, or fly ash from electric utilities. These materials can replace corresponding raw materials that would have to be mined.

Burning wastes as fuel can reduce the need for virgin fuels to run the kiln, can treat hazardous waste, and can reduce the quantity of wastes buried in landfills, incinerated, or otherwise disposed. The practice can also reduce plant operating costs, improving competitiveness.

Hazardous Waste Management

In 2005, cement plants reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 17,000 tons of hazardous waste. However, only 18 of 115 facilities in the sector reported to BR, so the data may present an incomplete picture of the sector's generation of hazardous waste. For instance, 1 facility generated 32% of the sector's reported RCRA hazardous wastes, while 4 of the 18 generated almost 86% of the reported wastes.[26] Most of the generated hazardous waste reported was from pollution control and hazardous waste management activities.[27]



The sector tends to manage more wastes than it generates because some facilities receive hazardous waste from offsite for use as fuel. The sector reported managing 31,000 tons of hazardous waste in 2005. A majority of the waste was managed through reclamation and recovery activities, almost all of which was through energy recovery.

Some cement companies have subsidiaries that operate as fuel blenders that accept, store, and process (e.g., fuel blending) hazardous waste. Estimating the flow of hazardous waste into and out of these subsidiaries and into and out of individual cement facilities is difficult to do but may be examined in future reports.

Waste Management Reported to TRI

In 2005, the Cement Manufacturing sector reported managing 425 million absolute lbs. of TRI chemicals as waste. As shown in Figure 4, when normalized by annual clinker production, this quantity represented a 24% reduction since 1996. The downward trend indicates that less waste was generated per ton of clinker in the sector in 2005. In 2005, 3% of TRI-reported waste was disposed or released, while 95% was used for energy recovery. The remaining 2% was recycled or treated.[28]

In 2005, the sector reported disposing 2.9 million lbs. of TRI chemicals to land or transferring the chemicals to offsite locations for disposal. As shown in Table 3, metals dominated the sector's TRI disposals. Major sources of these disposals are metals in CKD collected in air pollution particulate control systems. Metals from raw materials or fuels are usually bound to the clinker product, except for metals that are partly or completely volatilized in the kiln system (such as mercury, thallium, or cadmium).

Additional Environmental Management Activities

PCA set four performance measure goals regarding: CO_2, CKD, environmental management systems (EMS), and energy efficiency.

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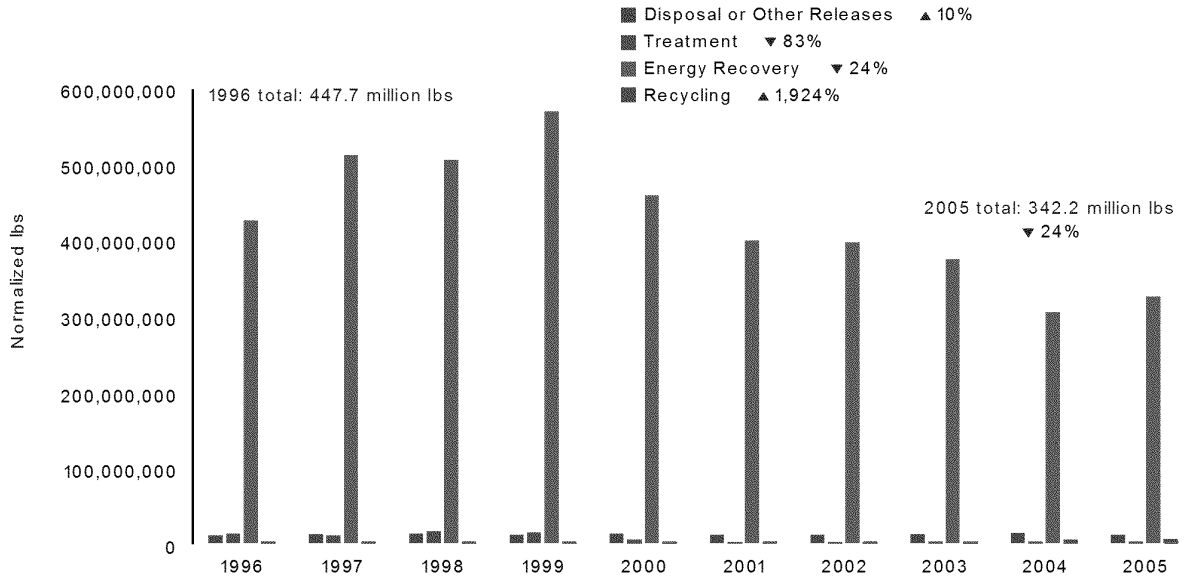
Figure 4

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual clinker production.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Geological Survey

Table 3

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Barium	173,500[3]	14
Chromium	97,500	32
Lead	620,200	49
Manganese	974,700	18
Mercury	1,500	39
Nickel	55,900	15
Zinc	711,700	11
Percentage of Sector Total	**90%**[4]	**48%**[5]

Notes:
1. 2.9 million lbs. total sector disposals.
2. 109 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 90% of the sector's disposals.
5. 48% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

As noted above, PCA member companies achieved their CKD disposal goal in 2004. Pursuant to the goal to reduce CO_2 emissions, PCA introduced guidelines for greater use of limestone as a raw material that could reduce CO_2 generation by more than 2.5 million tons per year. The guidelines recommend upgrading facilities with efficient, lower-emitting equipment, improving product formulation to reduce energy and natural resource needs, and conducting new research and development into cement and concrete applications that are more energy efficient and durable.[29]

An EMS is a set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency. PCA adopted a target to have at least 75% of U.S. cement plants use an auditable and verifiable EMS by the end of 2010 and 90% by the end of 2020.

For the energy efficiency performance measure, PCA adopted a year 2020 voluntary target of 20% improvement (from 1990 baseline) in energy efficiency. This is measured by total Btu-equivalent per unit of cementitious product.

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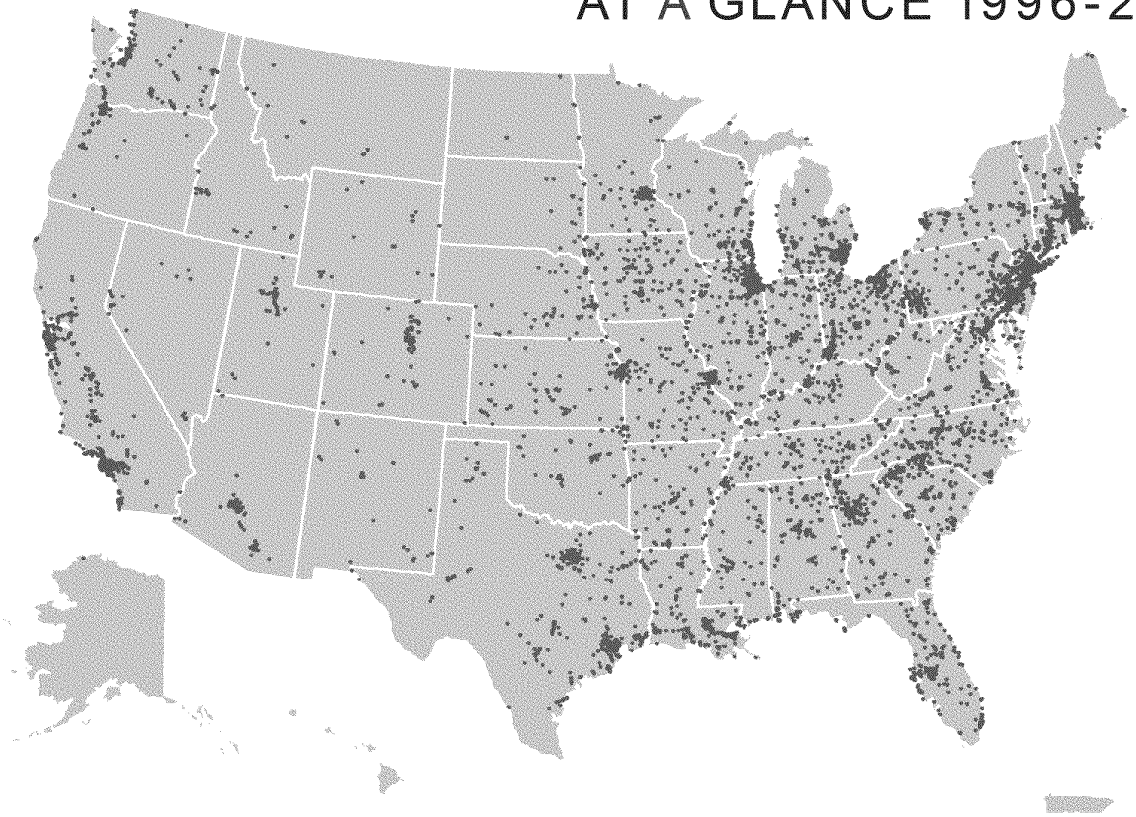
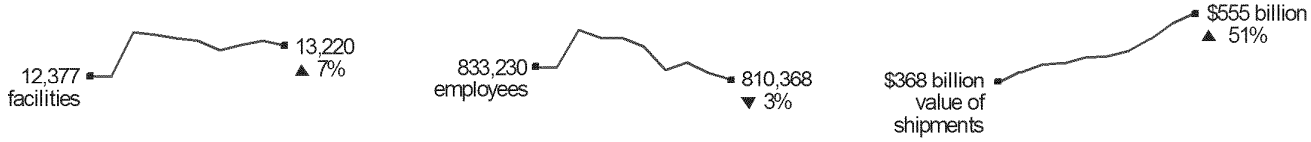
ChemiCal manufaCturing

AT A GLANCE 1996-2005[1]





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Latest Environmental Statistics[2]

Energy Use: 3.8 quadrillion Btu

Emissions of Criteria Air Pollutants: 1.5 million tons

Releases of Chemicals Reported to TRI: 540.8 million lbs.

air emissions: 201 million lbs.

Water Discharges: 42.7 million lbs.

Waste Disposals: 297 million lbs.

Recycling, Energy Recovery, or Treatment: 10.9 billion lbs.

Hazardous Waste Generated: 23.8 million tons

Hazardous Waste Managed: 26.1 million tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

Chemical Manufacturing facilities transform raw materials (e.g., oil, natural gas, water, minerals, metals) into tens of thousands of different products, including bulk chemicals, plastics, pharmaceuticals, and consumer goods, as well as produce inputs to agriculture, manufacturing, and construction industries. The sector is categorized into "commodity" and "specialty-batch" production.[3]

- Commodity manufacturers create products in large quantities under continuous processing conditions. The small number of shutdowns affects the potential to make adjustments such as equipment retrofits and upgrades.
- Specialty-batch manufacturers develop products for particular "niche" markets, making complex products in small quantities. These manufacturers change their process lines several times per year, providing more opportunities for environmental improvements but also making environmental compliance more complicated. In this report, the specialty-batch subsector is characterized by a facility list based on membership with the Synthetic Organic Chemical Manufacturers Association (SOCMA).[4]

Throughout this chapter, the distinction is made between "all chemical manufacturing" and "specialty-batch manufacturing," whenever separate data are available. "All chemical manufacturing" includes both commodity and specialty-batch processors.

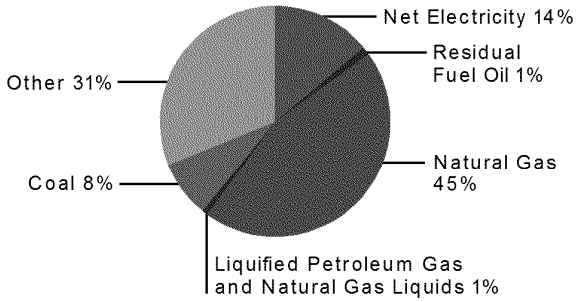
The sector represents about 12% of all U.S. manufacturing revenue based on value of shipments (VOS).

Energy Use

Chemical Manufacturing is an energy-intensive sector, using a total of 3.8 quadrillion Btu in fuel for energy purposes. Along with using fuels to supply the energy needs of facility operations, the sector uses fossil fuels—primarily natural gas and oil—as raw materials in the production of many products. Organic chemicals require the most fossil fuel. Feedstock use of fossil fuels is also common in the bulk petrochemical and fertilizer industries.[5]

Figure 1
Fuel Use for Energy 2002

Total: 3.8 quadrillion Btu



Notes:
1. Other is net steam (the sum of purchases, generation from renewables, and net transfers), and other energy that respondents indicated was used to produce heat and power.
2. Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

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Chemical facilities purchase electricity and produce energy from a variety of fuels. Natural gas was the primary fuel that the sector used in 2002, as shown in Figure 1. Net electricity was the third largest source of power for the sector in 2002.

Chemical manufacturers have opportunities for short- and long-term fuel switching, whereby they can reduce one energy source in favor of another with fewer emissions or greater efficiency. With the already high prices of natural gas, many facilities that can switch to alternative fuels from natural gas are already doing so.[6] Facilities could switch from emissions-intensive fuels, such as coal, to lower-emission fuels such as natural gas, but they have little cost incentive to do so; natural gas is more expensive than coal. Future energy consumption of all fuels is expected to increase in chemical manufacturing, and long-term fuel switching potential relies heavily on the price of natural gas.[7]

Reducing Electricity Demand

Sometimes the best alternative energy source is not a fuel. Hexion Specialty Chemical, Inc., of South Glens Falls, NY, realized a 21% reduction in electrical demand with no excess emissions when the facility installed a backpressure induction turbine generator powered by excess process steam. In addition to "free" energy, reductions in water usage and boiler treatment chemicals resulted as benefits of this pollution prevention project.[8]

Cogeneration, or combined heat and power (CHP), increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source. Cogeneration and self-generation of electricity are important in the chemical industry. The sector uses cogeneration to generate almost one third of the electricity it consumes.[9] Expanded application and further development offer the potential for additional opportunities in fuel switching and energy savings.

Energy Cogeneration and Conservation

In 1994, Dow committed to reducing the company's global energy intensity by 20% by 2005. In 2005, Dow improved by 22% over 1994, reducing energy use by more than 370 trillion Btu. In 2006, Dow's Freeport, TX, site replaced an older gas turbine with a more efficient steam generating plant and took other steps, such as switching to byproduct fuels, to reduce its energy intensity 2.6% relative to 2005, saving 3.6 trillion Btu and approximately $25 million. Overall, the company saved an estimated 5.4 trillion Btu of energy in 2006, with associated direct carbon dioxide (CO_2) emission reductions of 382,821 tons.[10]

Plant Energy Reduction Program

The DuPont Sabine River Works site, in Orange, TX, achieved major reductions in power generation and transmission using a data-driven approach to process improvement. Operators, supervisors, and engineers created an at-a-glance "dashboard" with data from numerous sources that compares optimal to actual performance, shows real-time cost impacts, and highlights underperforming processes. If improvements are needed, the dashboard lists recommended corrective actions, operating procedures, and diagnostic tools. Operators improved efficiency from 10% below expectations to 15% above, sometimes performing at the theoretical limit. Annualized energy savings have been 25%, with associated CO_2 emissions reductions of 10,962 tons.[11]

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in the raw materials or fuels used in chemical manufacturing processes, and as intermediates. They can also be byproducts, products from side reactions, or internal end products. CAPs and GHGs are also generated as combustion byproducts from onsite combustion of fuels.

Air Emissions Reported to TRI

In 2005, 3,096 facilities in the Chemical Manufacturing sector reported 201 million absolute lbs. of air emissions. Between 1996 and 2005, absolute TRI-reported air emissions declined by 51%, as shown in Figure 2a. When normalized by the sector's value of shipments over the period, air emissions decreased 61%, as seen in Figure 2b.[12] Facility-level analysis of TRI data indicate that this reduction was driven by a decline in the quantity of chemicals released by facilities that reported across all years, rather than being driven by a reduced number of reporters.

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model

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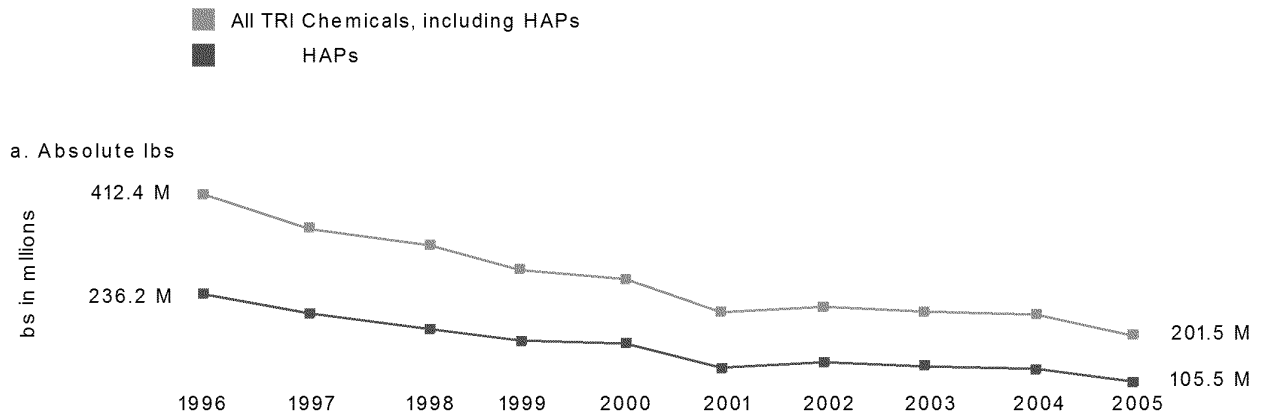
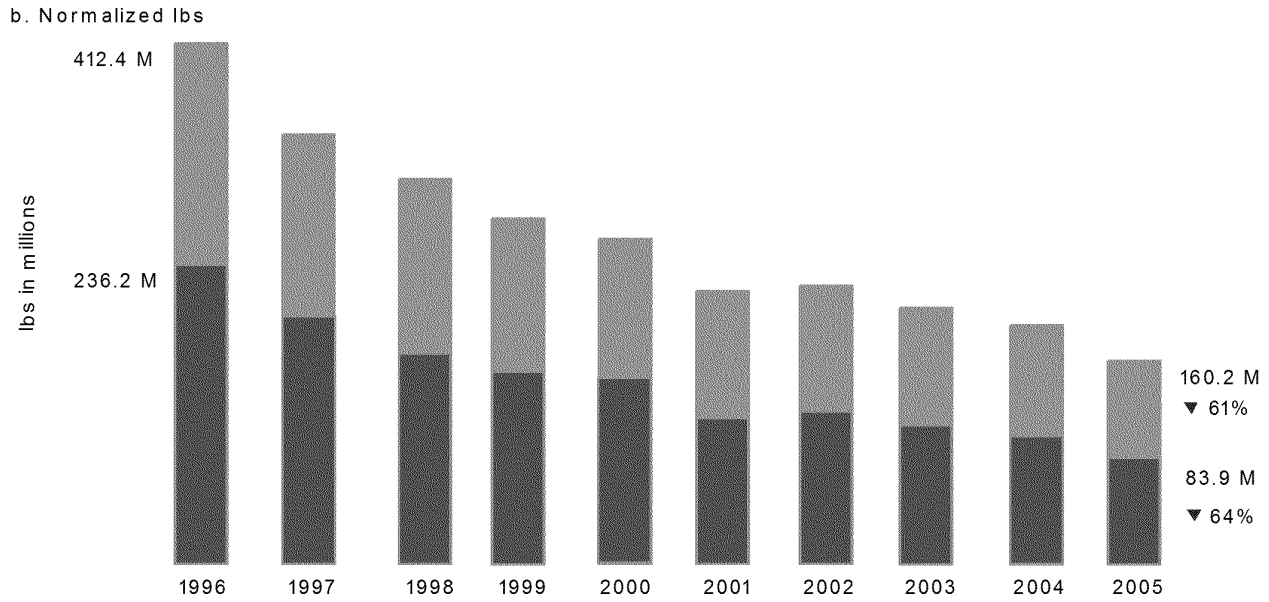
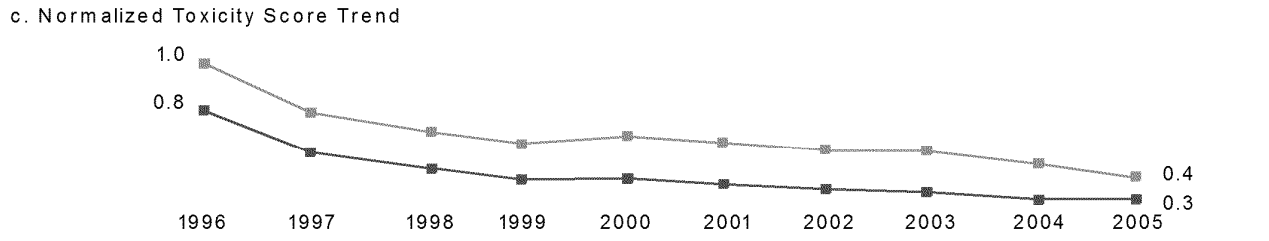
Figure 2

Air Emissions Reported to TRI 1996-2005







Note:
Normalized by annual value of shipments.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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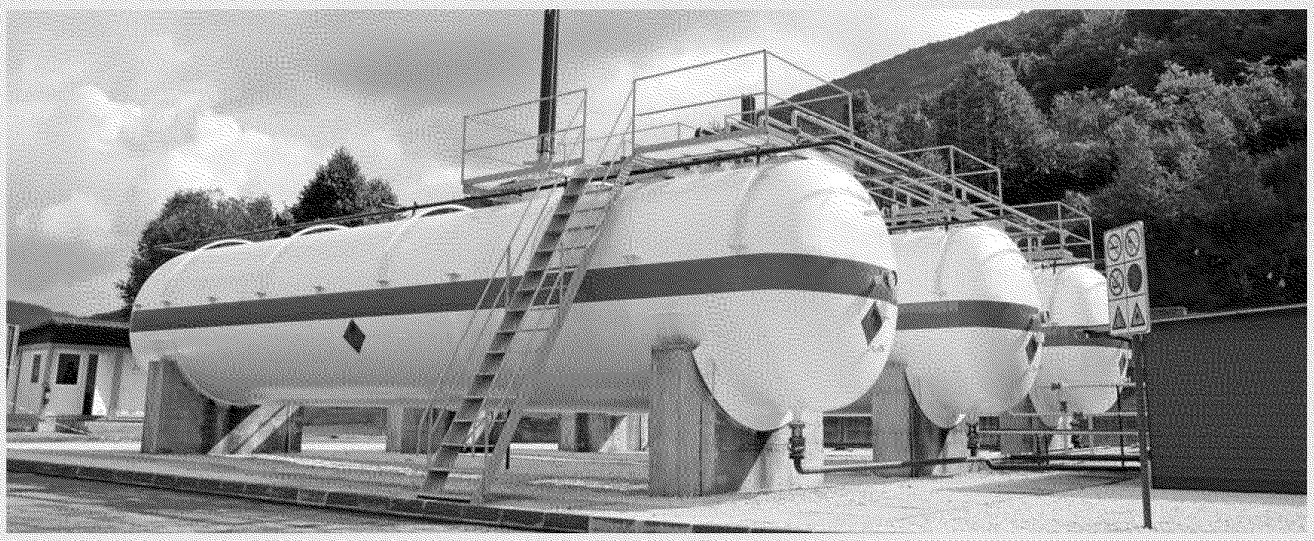

conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories. Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c.

The TRI list of toxic chemicals includes all but 6 of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. In absolute pounds, HAPs accounted for 52% of the sector's air emissions reported to TRI in 2005, and 74% of the sector's total Toxicity Score.[13] Trends in emissions of HAPs, based on pounds and on the Toxicity Scores, showed very similar declines to the trends in air emissions for all TRI chemicals.[14]

Over the same period, air emissions from the specialty-batch subsector declined by 49%.[15] The subsector is considerably smaller than the Chemical Manufacturing sector as a whole, with 185 facilities reporting air emissions to TRI in 2005. The specialty-batch chemical subsector's Toxicity Scores declined 60% from 1996 to 2005. However, because there are fewer facilities, changes at a few sites, particularly those reporting chemicals with a high Toxicity Score, can significantly impact overall subsector trends.[16]

Table 1 presents the top TRI-reported chemicals emitted to air by the chemical manufacturing sector based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Ammonia and methanol were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005.

2) Percentage of Toxicity Score. The top chemicals based on Toxicity Score included chlorine and sulfuric acid. These chemicals have moderate toxicity weights, but were released in large quantities, resulting in high Toxicity Scores.

Table 1

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Acrolein[3]	49,000	8%[4]	37
Ammonia	50,421,000	2%	589
Carbon Disulfide	10,111,000	<1%	54
Carbonyl Sulfide	12,852,000	4%	33
Certain Glycol Ethers	600,000	<1%	484
Chlorine	1,048,000	18%	285
Chromium	32,000	5%[5]	103
Ethylene	16,601,000	<1%	143
Manganese	138,000	10%	94
Methanol	19,279,000	<1%	783
Sulfuric Acid	3,586,000	13%	122
Toluene	6,961,000	<1%	693
Xylene (Mixed Isomers)	2,793,000	<1%	585
Percentage of Sector Total	**62%**[6]	**60%**[7]	**65%**[8]

Notes:
1. 201 million pounds total sector air releases.
2. 3,096 total TRI reporters in the sector.
3. *Italics* indicate a hazardous air pollutant under section 112 of the Clean Air Act.
4. Red indicates the chemical is one of the top five chemicals reported in the given category.
5. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
6. Chemicals in this list represent 62% of the sector's air emissions.
7. Chemicals in this list represent 60% of the sector's Toxicity Score.
8. 65% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

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Acrolein and chromium were released in smaller quantities but have high Toxicity Scores.

3) Number of Facilities Reporting. Methanol was the most frequently reported chemical, with one-quarter of the TRI-filers in the sector reporting methanol air emissions.

The top 10 chemicals based on Toxicity Scores accounted for 71% of the total Toxicity Scores, with chlorine, sulfuric acid, and manganese accounting for 40% of Toxicity Scores. This list of top 10 has been fairly consistent for the past five years. However, TRI-reported releases of acrolein declined from 1990 until 2001, but then more than doubled to 49,000 pounds in 2005. Facility-level analysis of acrolein releases indicates that the increase may be a result of the growing use of ethanol and biofuels. Both the number of facilities reporting and the volume of releases have increased under SIC 2869 (Industrial Organic Chemicals, NEC) and NAICS 325193 (Ethyl Alcohol Manufacturing). The recent fluctuations in releases of acrolein have been driven generally by 10 or fewer facilities, indicating the potential for targeted reduction efforts.

For the specialty-batch subsector, as with the Chemical Manufacturing sector as a whole, methanol was the most frequently reported chemical released to air in 2005, with 104 facilities reporting, and chlorine was the top-ranked chemical based on Toxicity Scores. The top-ranked chemicals based on pounds of air emissions from facilities in the specialty-batch subsector were ethylene (1.6 million lbs.) and toluene (1 million lbs.).[17]

Criteria Air Pollutants

CAP emissions are generated by onsite energy production using fuels such as coal, oil, and gas, and also by some chemical manufacturing processes.[18] Table 2 shows CAP and volatile organic compound (VOC) emissions from the sector for 2002.

Table 2
Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	482,000
NO_X	309,000
PM_{10}	57,000
$PM_{2.5}$	39,000
CO	476,000
VOCs	175,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.
Source: U.S. Environmental Protection Agency

Reduced Energy Use and CO_2 Emissions

Albemarle Corporation initiated a program in 2006 to reduce energy consumption by 12% over two years. Projects involving preventive maintenance and steam leaks were especially successful. The company used weekly plant audits to evaluate progress, identify opportunities, and establish corrective actions. Using low capital-intensive efficiency improvements and other means, the company achieved 66% of its goal in the first year. Annualized energy savings were more than 8%, representing 603,778 million Btu saved and 35,019 tons of CO_2 emissions avoided.[19]

Greenhouse Gases

Chemical manufacturers directly emit GHGs from the combustion of fossil fuels and from production processes. Non-combustion emissions occur from the use of fossil fuels as feedstocks and the use of other raw materials. Such emissions include nitrous oxide (N_2O), fluoroform (HFC-23), CO_2, and methane (CH_4). The largest process-related sources of GHG emissions include production of hydrochlorofluorocarbons (HCFCs), ammonia, and acids such as nitric and adipic acid.[20] The generation of electricity purchased by chemical manufacturers also emits GHGs.

The American Chemistry Council (ACC) participates in Climate VISION, a U.S. Department of Energy voluntary partnership effort responding to the President's goal of reducing GHG intensity, that is, the ratio of greenhouse gases to economic output.[21] Through this program, ACC members committed to reduce their GHG emissions intensity 18% from 1990 levels by 2012. ACC reports that members have already achieved this goal.[22] The companies reduced their GHG intensity by more than 30% since 1992; GHG intensity fell 5% between 2003 and 2005.[23]

Water Use and Discharges

Water use varies widely within the sector, depending on the products manufactured and production processes used. The primary uses of water are for non-contact cooling, steam applications, and product processing.[24] The production of various chemicals requires different amounts of water. For example, producing silicon-based chemicals requires large quantities of water, yet the top manufactured chemicals by volume (including nitrogen, ethylene, ammonia, phosphoric acid, propylene, and polyethylene) require far less water during production.[25] Throughout the sector, more than 80% of the water used for cooling and steam is recycled; process water recycling varies widely.[26] There are currently no aggregate data available on the quantity of water used by the sector.

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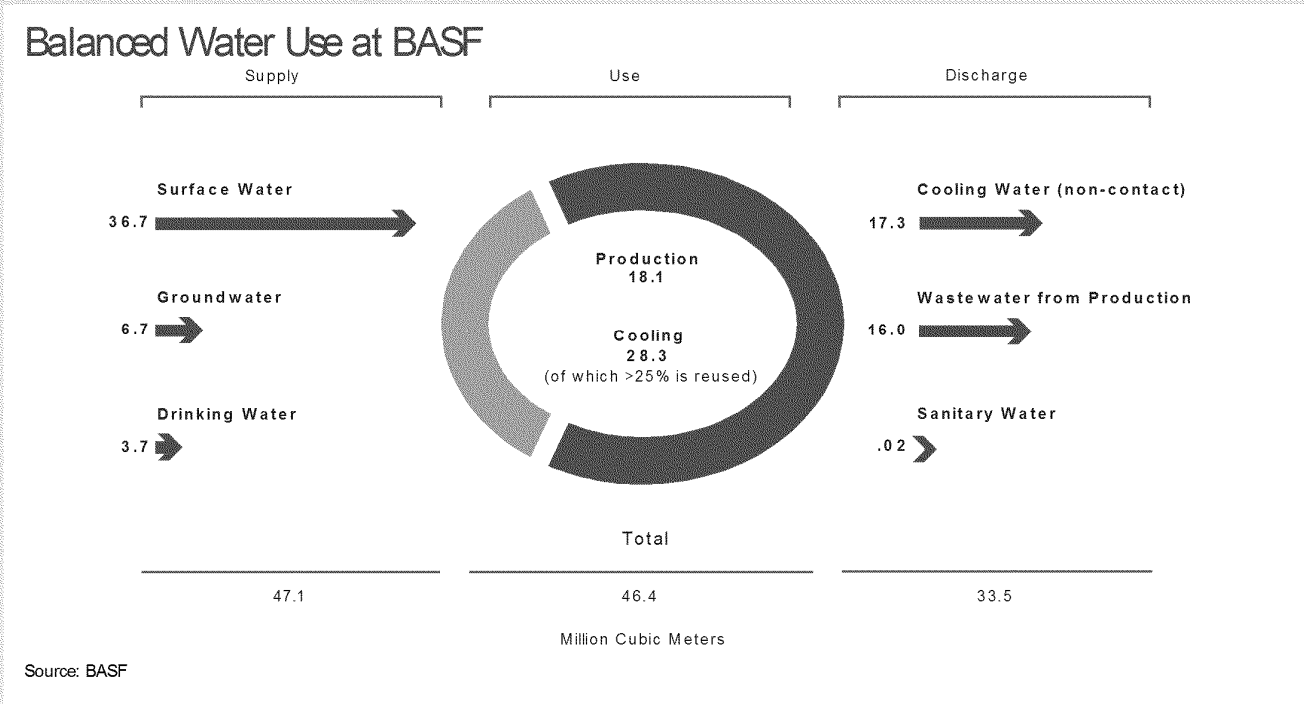

Source: BASF

Balanced Water Use at BASF

BASF's U.S. operations used an estimated 46.4 million cubic meters of water in 2006. Of that amount, 18.1 million cubic meters of water was used for production and 28.3 million cubic meters for cooling purposes. More than 25% of the cooling water is reused. BASF focuses primarily on water recycling as part of its water conservation measures, including regular maintenance on closed loop systems that circulate water, boiler blowdown and condensate recovery, and water reuse for vessels and piping clean-outs.[27]

Every facility discharging process wastewater directly to waterways must apply for a National Pollutant Discharge Elimination System (NPDES) permit. The permits typically set numeric limits on specific pollutants and include monitoring and reporting requirements. Approximately 1,700 facilities in the sector have NPDES permits.[28] Regulated pollutant discharges can vary depending on the characteristics of chemicals being manufactured. Major factors include total suspended solids, presence of various metals, biological or chemical oxygen demand, and pH levels.[29]

Sector-wide, 801 chemical manufacturing facilities reported water discharges of TRI chemicals in 2005, totaling 42.7 million lbs., including direct discharges to waterways of any TRI chemical and discharges of metals to Publicly Owned Treatment Works (POTWs). This represented a decline of 57% between 1996 and 2005 for the chemical industry as a whole. Specialty-batch manufacturers reported water discharges of 2.7 million lbs., which represented a decline of 81%.[30]

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Water Conservation and Efficiency

Arizona Chemical's manufacturing facility in Port St. Joe, FL, reduced well water usage from two onsite water wells. The facility installed multiple heat exchangers, thereby reducing cooling water usage. The company also modified cooling towers to improve efficiency, upgraded and cleaned equipment to improve heat transfer, repaired and upgraded steam traps, implemented a program to identify and repair stream leaks, and changed operating procedures to minimize water usage. The plant reduced its annual well water usage while increasing its annual production. The company reduced its well water use relative to production by nearly 13% from 2002 to 2005.[31]

In addition to being regulated for direct and POTW discharges, facilities with materials exposed to precipitation are regulated for stormwater runoff, usually under a general permit that provides sector-specific limits. While some facilities have stormwater permits, it is not a predominant issue of concern for the sector.

Water conservation and minimization practices for the sector include water measurement and management, water reuse, reducing the use of cooling water, eliminating system leaks, educating employees on conservation techniques, and development of processes that require less water.[32]

Waste Generation and Management

Hazardous Waste Management

In 2005, chemical manufacturers reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 23.8 million tons of hazardous waste, accounting for 62% of the hazardous waste generated nationally. At 37% and 32% of the total, respectively, production-related waste and pollution control (e.g., wastes captured in air pollution control equipment and wastewater treatment sludge) were the largest sources of hazardous waste generation. The sector reported managing 26.1 million tons of hazardous waste. According to the reports to BR, most of the sector's hazardous waste was managed through disposal.[33]

The specialty-batch chemicals subsector reported generating 414,000 tons of hazardous waste. For the subsector, 85% of the hazardous waste was generated from product and byproduct processing and pollution control processes (primarily from wastewater treatment operations). Almost 80% of the waste was treated or recovered/reclaimed, while 20% was disposed.[34]

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Waste Management Reported to TRI

In 2005, chemical manufacturers reported managing 11.4 billion absolute lbs. of TRI chemicals in waste. When normalized by the sector's VOS, this was 12% less than 1996. Figure 3 shows how the sector managed this waste. In 2005, 5% of TRI-reported waste was released or disposed. Most of the waste disposed in 2005 went to underground injection wells, and the remainder was landfilled or placed in surface impoundments. In the same year, 15% was recovered for energy use, 39% was recycled, and 41% was treated.[35] When normalized by VOS between 1996 and 2005, the quantity of waste treated increased while the use of other management activities decreased.

Specialty-batch producers reported 1.2 billion lbs. of total waste managed in 2005. Of this quantity, 1% was released or disposed, 9% was used for energy recovery, 26% was treated, and 65% was recycled.[36]

For the overall sector, nitrate compounds and manganese were disposed in the greatest quantities and accounted for about one-third of disposals, while zinc and ammonia were the most frequently reported chemicals disposed, as indicated in Table 3.

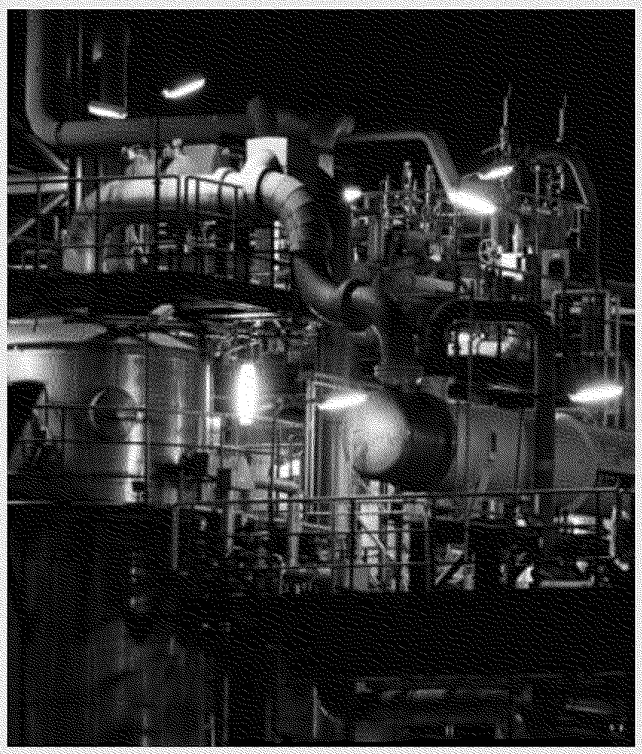
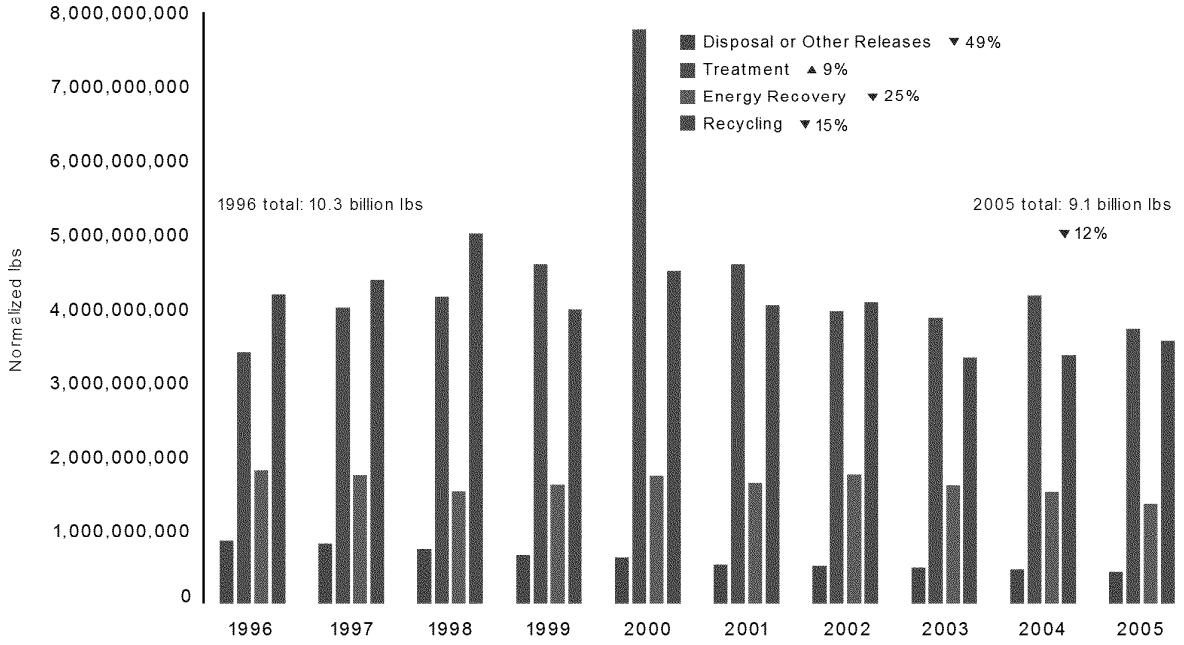


Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual value of shipments.
2. Disposal and Other Releases includes air emissions, water discharges, and land disposals.
3. The apparent spike in treatment in 2000 was due to the report filed by a single facility.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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Table 3

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Acetonitrile	16,700,000[3]	22
Ammonia	27,850,000	164
Copper	3,198,000	139
Lead	3,067,000	363
Manganese	49,873,000	91
Methanol	16,452,000	146
Nitrate Compounds	54,996,000	103
Zinc	8,946,000	344
Percentage of Sector Total	**61%**[4]	**27%**[5]

Notes:
1. 297 million pounds total sector disposals.
2. 3,096 total TRI reporters in the sector.
3. Red indicates the chemical is one of top five chemicals reported in the given category.
4. Chemicals in this list represent 61% of the sector's disposals.
5. 27% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Waste Minimization and Utility Conservation

The Lockport, NY, facility of Isochem Inc., a phosgene and phosgene derivative manufacturer, implemented utility conservation, CO reduction, phosgene recovery, and distillation and reuse of process solvents. By re-piping process equipment and installing nitrogen flow meters, the facility pinpointed wasted resources, saved energy, and reduced onsite CO_2 emissions. Nitrogen reductions brought significant supplier energy savings and CO_2 reductions. By adding mass flow meters, automatic control valves, and some additional instrumentation, the facility reduced its need for excess CO used in high-quality phosgene production by nearly 15%. The changes also reduced onsite city water, caustic water, and sewer discharges, and reduced company and fuel supplier CO_2 emissions. The company initiated a novel approach of evaporating excess phosgene and recovering it for reuse. The installation of a solvent recovery distillation column permits purification of used organic solvents for reuse as a new raw material stream. This new process has reduced both raw material purchases of solvents and organic waste generation.[37] In 2006 the distillation equipment realized an annual total waste reduction of 609 tons.[38]

Additional Environmental Management Activities

An environmental management system is a set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency. SOCMA's ChemStewards program is an initiative to manage compliance with federal requirements and improve processes and efficiencies.[39] The three-tiered program allows SOCMA member companies to develop individual environment, health, safety, and security management systems. ChemStewards implementation guidance includes manuals, online assistance, regional meetings, and peer information exchange.

ACC's Responsible Care program offers a system for managing performance in environmental impact, health, safety, and security. All ACC member companies are required to have CEO-level commitments to Responsible Care. Program elements include publicly reporting performance, implementing the security code, applying a management system, and obtaining independent certification for the management system.[40]

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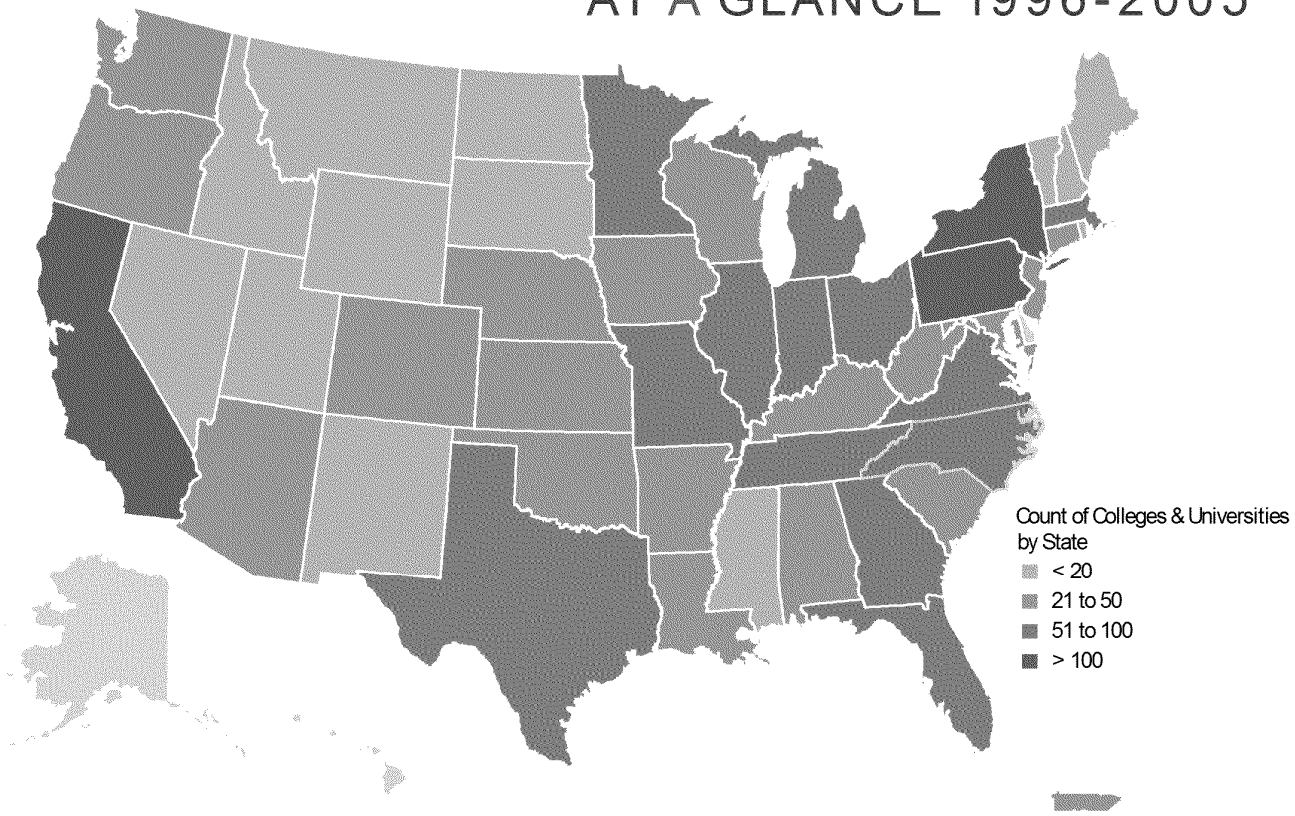
Colleges & universities

AT A GLANCE 1996-2005[1]



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Latest Environmental Statistics[2]

Emissions of Criteria Air Pollutants: 73,000 tons

Hazardous Waste Generated: 26,000 tons

Hazardous Waste Managed: 24,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

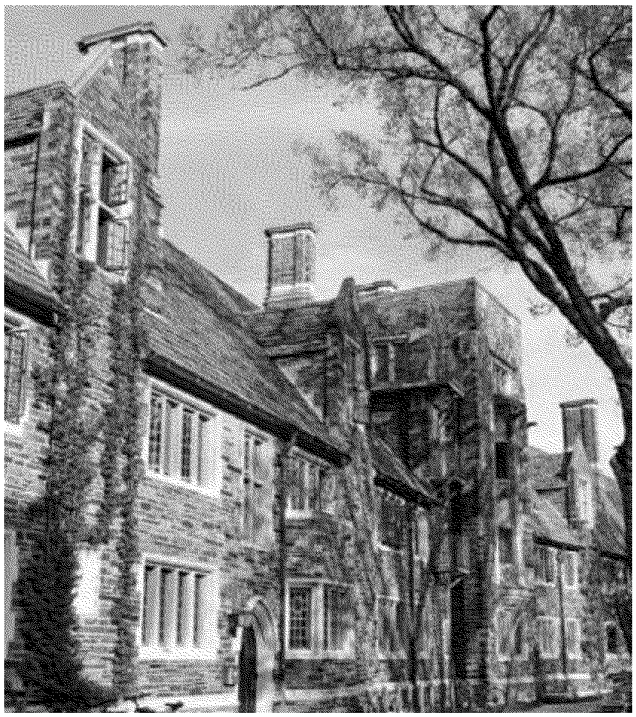
The Colleges & Universities sector includes schools granting degrees at baccalaureate or graduate levels such as major universities, military academies, business colleges, medical and law schools, music conservatories, and seminaries.

Facilities of the sector have a variety of environmental impacts across all environmental media. Campuses may, for example, operate power plants and wastewater treatment facilities, undertake construction projects, and maintain large areas of landscaping. Many consume large quantities of energy, generate tons of municipal waste and small quantities of hazardous wastes (primarily through laboratories), and manage stormwater runoff.

Energy Use

There are no aggregate national data on energy use at campuses in the United States. Campuses use energy in many types of facilities, including classroom buildings, residences, laboratories, performing arts venues, and sports facilities. Campus parking lots and walkways use electricity to provide lighting. Heating, ventilation, and air conditioning units consume energy from natural gas, liquid propane, and electricity. Activities related to grounds keeping, transportation, and security also consume fossil fuels and electricity.

Many schools are taking action to improve their energy efficiency. For example, more than 75 colleges and universities have pledged to purchase power from renewable energy sources such as solar, wind, geothermal, biomass, and hydroelectric as part of EPA's Green Power Partnership. Schools in the Partnership annually purchase more than 1 billion kilowatt hours of green power, which is enough to power nearly 100,000 average U.S. houses for a year.[3]



Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and others. The sector's air emissions originate primarily from fossil fuel combustion, but also from various sources such as construction, laboratory chemical reactions, and refrigeration systems. Indirect air emissions include emissions related to vehicle use and maintenance, campus transit systems, commuting, deliveries, and generation of purchased electricity. Sector-wide air emission information is not available, although some facilities are conducting emission inventories.

Saving Energy and Reducing Emissions with CHP

Kent State University in Ohio took energy efficiency a step further by generating its own power with a new combined heat and power (CHP) plant that also is a working lab. CHP, also called cogeneration, increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source. The system's 13-megawatt, natural gas-fired turbines produce almost 90% of the university's electricity during the winter and 60% during the summer. The system also uses waste heat from the turbines to produce half of the university's steam. The overall system reduces direct carbon dioxide (CO_2) emissions by an estimated 13,000 tons per year, equivalent to the emissions from 2,100 cars. Kent State received a 2006 EPA ENERGY STAR CHP award for this effort.[4]

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Criteria Air Pollutants

Most CAP emissions in the sector result from burning of fossil fuels. In 2002, sulfur dioxide (SO_2) accounted for the largest volume of CAP emissions, and was emitted by 95% of the facilities included in EPA's National Emissions Inventory.[5] Table 1 shows CAP and volatile organic compound (VOC) emissions from 442 facilities in the sector for 2002.

Table 1

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	39,000
NO_X	20,000
PM_{10}	2,000
$PM_{2.5}$	1,000
CO	11,000
VOCs	1,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Greenhouse Gases

Despite the lack of aggregate trend data on GHG emissions, there is a rapidly growing campus awareness of GHG impacts. A growing number of school officials are committing to take action. More than 480 presidents of higher education institutions have committed to the American College and University Presidents Climate Commitment (ACUPCC). ACUPCC's goal is for participating schools to develop plans to achieve climate neutrality, starting with campus-wide GHG emission inventories and institutional action plans. Tangible actions may include green building, use of ENERGY STAR-certified products, the purchase of power from renewable resources, and increased use of public transportation.

Energy Conservation and Sustainability

Arizona State University (ASU) began a program to reduce electricity, natural gas, and water use in 2000. Lighting and system upgrades reduced consumption by 53 million kilowatt-hours per year. From 2002 to 2006, ASU reduced its energy bill by 10%, saving $3.3 million annually. ASU received a 2007 ENERGY STAR CHP Award in recognition of a new natural gas CHP system that reduced fuel use by about 21% and CO_2 emissions by an estimated 16,000 tons per year. In March 2007 the ASU President pledged under ACUPCC, among other things, to develop an action plan within two years to become carbon neutral and to include sustainability in the curriculum. ASU recently set a goal of reducing its energy bill another 10%.[6]

Water Use and Discharges

Sector facilities use water in many ways, including academic and residential buildings, student centers, cafeterias, laboratory and sporting facilities, hospitals and clinics, and landscaping and agricultural operations. For most campuses, clean water comes from publicly owned facilities, and water discharges are sent to Publicly Owned Treatment Works. A mix of modern, efficient water systems and older, inefficient systems exists on campuses.

EPA effluent limitation guidelines vary according to campus makeup. For example, on-campus power plants may be regulated if power is distributed and sold, while effluents from educational research laboratories currently are not regulated.[7] Stormwater discharges may include fertilizers and pesticides from landscaping. Currently, the sector's stormwater discharges are not regulated, although there may be facility-specific requirements for certain industrial operations.[8]

An Educational Green Building

At Oberlin College in Ohio, the Adam Joseph Lewis Center for Environmental Studies is an acclaimed integrated building and landscape system for study and proactive energy and environmental management. The center uses water-saving sinks and toilets. Its "Living Machine" system combines conventional water treatment and the center's wetland ecosystem to remove organic wastes, nutrients, and pathogens, allowing 60% to 80% of the water used to be treated and re-used in toilets and on the center's landscape. Stormwater from the center's roof, sidewalk, and parking lot drains into a wetland (which cleanses it) and into a 9,700-gallon cistern. During drier periods, rainwater stored in the cistern is used to maintain the wetland.[9]

Waste Generation and Management

Although sector-wide information on the management of nonhazardous waste is not available,colleges and universities do generate, and can reduce or recycle, significant amounts of waste.[10]

In 2007, more than 200 colleges and universities participated in RecycleMania, sponsored by the National Recycling Coalition in partnership with EPA's WasteWise program, to increase campus recycling.[11] The number

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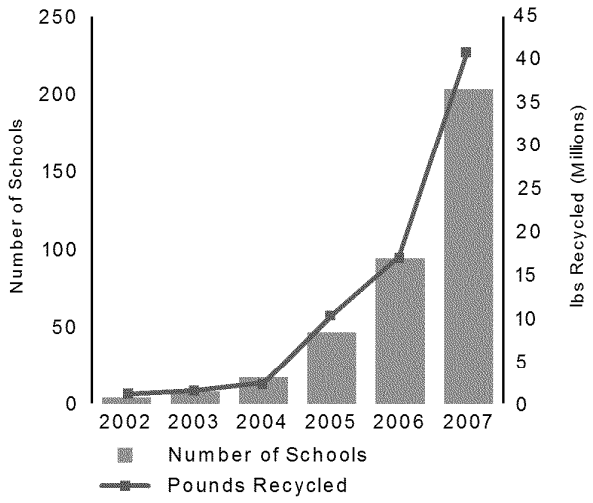
of schools participating and the amount of recyclables collected over the 10-week competition has doubled each year since starting in 2001, as shown in Figure 1. The 2007 competition reported a total of 41.3 million pounds of materials recycled. The materials collected prevented the discharge of 15,583 million metric tons of CO_2 equivalent—equating to GHG emissions from approximately 12,367 passenger cars in one year.[12]

Expanding Recycling

Rutgers University in New Jersey was EPA's WasteWise 2007 College/University Partner of the Year.[13] Rutgers recycled 14,356 tons of materials in 2006, an 11% increase over the previous year. As one of many activities, the University installed new pulping and dewatering machines that remove up to 80% of the moisture from food waste; the resulting pulp is donated as livestock feed. In 2006 the machines helped Rutgers recover 3,422 tons of food waste and avoid $758,929 in landfill costs.[14]

Figure 1

RecycleMania Participation and Results



Source: U.S. Environmental Protection Agency

Hazardous Waste Management

Colleges and universities generate hazardous waste from a variety of activities, such as laboratories, operation of pollution control devices, or remediation of past contamination.

Some 335 facilities reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 26,000 tons of hazardous waste in 2005. Of this total, 64% was material from state-mandated or voluntary cleanups, and 21% was laboratory wastes. More than 66% of the reported hazardous waste for the sector was lead, and more than 6% was ignitable waste, laboratory packs, and mercury.[15] In the same year, the sector reported managing 24,000 tons of hazardous waste.

Additional Environmental Management Activities

Although the sector lacks metrics for many parts of its environmental and energy footprint, a growing number of schools are developing sustainability programs and actively tracking their individual progress. The nonprofit Sustainable Endowments Institute is evaluating these efforts on the national level in its 2008 College Sustainability Report Card. The report evaluates campus and endowment sustainability activities at the 200 colleges and universities with the largest endowments in the United States and Canada. The Report Card provides information on best operational practices of leading schools in such categories as climate change and energy, food and recycling, green building, and transportation.

The 2008 Report Card shows a growing commitment to sustainability within the sector, with 68% of the evaluated schools showing an improved "grade" from a year ago. Fifty percent of the schools have adopted carbon reduction commitments, and 69% now have green building policies. Some 42% of the schools now have hybrid or electric vehicles in their fleets, and 37% now have full-time staff dedicated to sustainability.[16]

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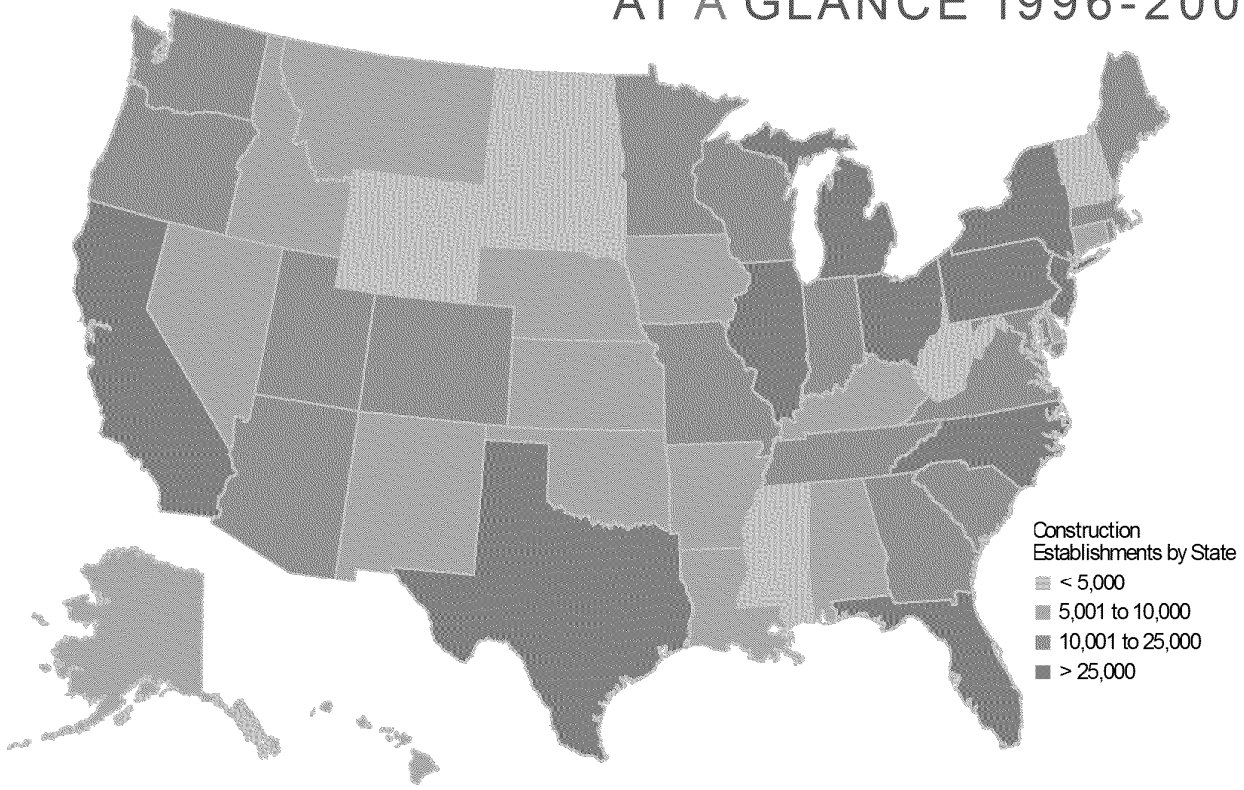
Construction

AT A GLANCE 1996-2005[1]



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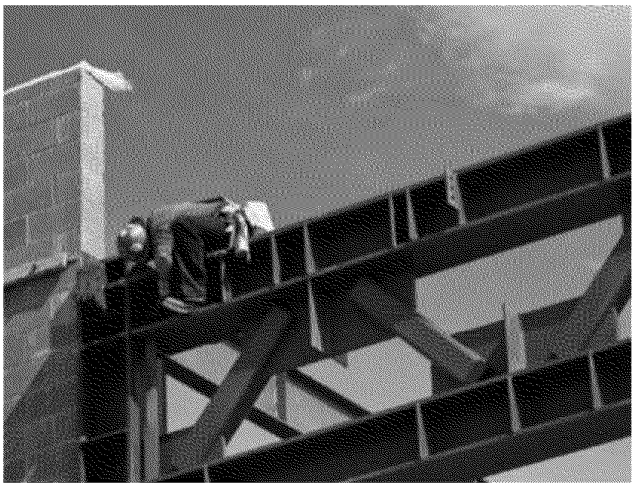

Latest Environmental Statistics[2]

Energy Use: 1.6 quadrillion Btu

Construction & Demolition Debris Generated: 331 million tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Construction sector consists of establishments engaged in constructing, renovating, and demolishing buildings and other engineering structures.[3] The sector includes contractors in commercial, residential, highway, heavy industrial, and municipal utility construction. Specialized trades within the sector include work that is commonly subcontracted, such as plumbing, heating, masonry, and painting.

Although residential construction has slowed in recent years, spending on overall construction nearly doubled over the past decade. In 2006, the value of construction put in place totaled $1.1 trillion, or 9% of the U.S. gross domestic product. Spending on residential construction totaled $647 billion; nonresidential spending totaled $545 billion.[4]

More than 90% of construction companies have fewer than 20 employees.[5] Tracking the environmental performance of the Construction sector presents challenges because of the large number of construction companies and construction sites, the prevalence of small businesses, and the lack of data. Data that are commonly available for manufacturing sectors, such as chemical releases from EPA's Toxics Release Inventory (TRI), are either not applicable to or not available for the Construction sector.

To address the measurement challenge, in September 2007 EPA recommended measures of performance for the sector covering energy use, greenhouse gas (GHG) emissions, diesel air emissions, stormwater compliance, construction and demolition (C&D) debris management, and green building practices.[6]

These measures indicate several trends:

- Construction-related energy use is increasing faster than the growth in construction activity.
- Many construction companies have begun retrofitting older diesel equipment, reducing air pollution.
- More construction sites are complying with the requirement to obtain stormwater permits, although the percentage of construction sites in compliance is still unknown.
- The percentage of C&D materials recycled varies widely from state to state; materials are recycled more in highway construction than building construction.
- In addition to constructing more green buildings, many contractors are "greening" their own operating practices.

Energy Use

The Construction sector uses energy to operate equipment, to transport materials to and from construction sites, and to power facilities. Nonroad (also called "off-road") diesel engines used by construction companies, for example, include a wide variety of loaders, bulldozers, backhoes, excavators, graders, pavers, scrapers, and other specialized equipment.[7] Construction consumed an estimated 1.6 quadrillion Btu in 2002, which was a 28% increase from about 1.25 quadrillion Btu in 1997.[8] During the same

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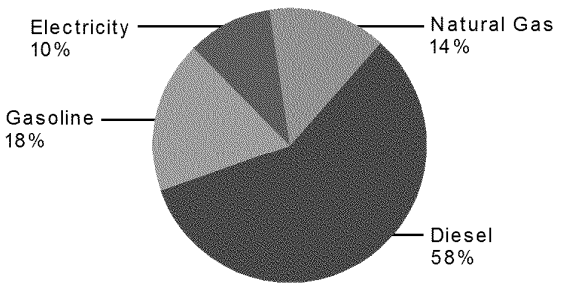
Figure 1

Fuel Use for Energy 2002

Total: 1.6 quadrillion Btu



Source: U.S. Environmental Protection Agency

Reduced Idling Cuts Fuel Use, Costs, and Pollution

Grace Pacific Corporation, a highway contractor in Hawaii, has started a program to reduce unnecessary idling. The company first compiled an inventory of its fuel use, idling time, and air emissions. The inventory provides a baseline for tracking performance. Company officials believe they can cut overall fuel consumption by 10% on Oahu, saving approximately $80,000 in fuel costs and reducing emissions substantially.[9]

period, the value of construction, measured in constant dollars, grew 22%.[10]

The Construction sector could save energy under related efforts to reduce diesel emissions, increase recycling, and otherwise promote green construction. Specific opportunities include reducing idling, maintaining equipment optimally, using biodiesel, buying materials locally (reducing transportation fuel use), improving energy efficiency in company facilities, recycling C&D materials, using industrial byproducts in construction, and using coal fly ash and other supplementary cementious materials (SCM) in the manufacture of concrete. The Construction sector uses more than 100 million tons of cement annually. For every ton of coal fly ash and other SCMs used as an additive to Portland cement, there is an estimated energy savings of 5 million Btu.[11]

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs) and GHGs. CAPs and GHGs are generated as combustion byproducts from onsite energy production. The primary air pollutants associated with the sector are particulate matter (PM) and nitrogen oxides (NO_X), which are emitted during operation of diesel equipment. Diesel engines also emit sulfur oxides (SO_X), hazardous air pollutants, and GHGs. Some construction sites generate PM as fugitive dust. The Construction sector emits GHGs directly from combustion of fossil fuels.

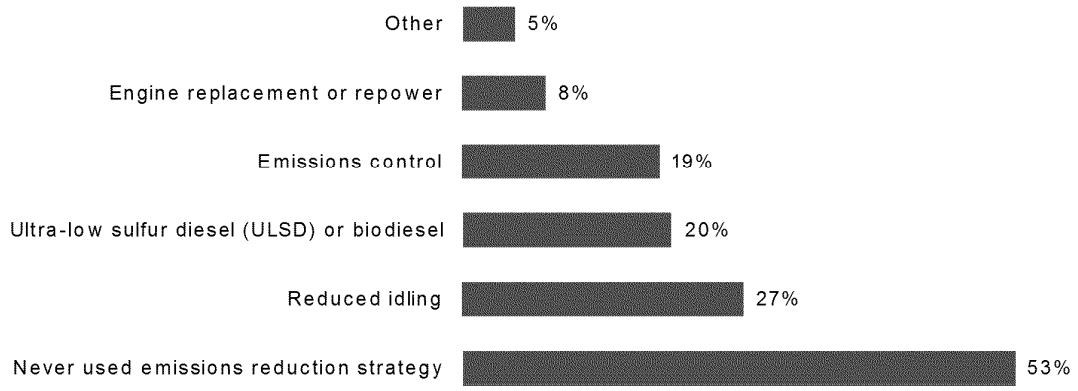
Criteria Air Pollutants

EPA has set standards for PM and NO_X emissions from new nonroad diesel engines. However, the standards will not apply to the approximately two million pieces of construction equipment already in use.

EPA's National Clean Diesel Campaign and various state programs are encouraging voluntary measures to reduce PM and NO_X emissions from existing diesel equipment. Measures include retrofitting with emissions control technologies and replacing or upgrading engines, as well as reducing idling and switching to cleaner fuels such as ultra-low sulfur diesel or biodiesel.

Figure 2

Diesel Emissions Reduction Strategies Used by Construction Firms - Industry Survey



Note:
Percentage is of survey respondents.

Source: Associated General Contractors of America

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Baseline data indicate that 40 construction equipment retrofit projects eliminated 39,747 tons of NO_X emissions and 7,793 tons of $PM_{2.5}$ emissions from 2003 through 2006.[12]

In 2007, the Associated General Contractors of America (AGC) surveyed its members about clean diesel strategies.[13] As shown in Figure 2, almost half of the 234 companies that responded have employed techniques to reduce emissions. Of those, nearly half undertook those measures voluntarily rather than in response to regulatory or contractual requirements.

Greenhouse Gases

GHG emissions from the Construction sector result from fuel consumed by on- and off-road construction equipment. A preliminary estimate of CO_2 emissions in 2002 from the sector's energy consumption is 114.1 million metric tons of CO_2 equivalent.[14] The generation of electricity purchased to provide power for construction equipment and offices also emits GHGs.

Stormwater Discharges

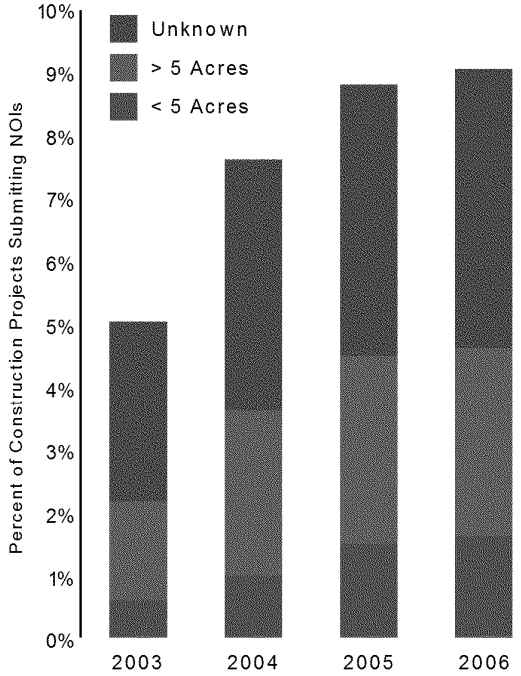
Stormwater runoff is one of the most significant environmental issues for the sector.[15] Runoff from construction sites may contain sediments, oil and grease, other pollutants, and trash. Paved or compacted ground increases the amount and rate of runoff because of reduced rainwater infiltration.

There are currently no EPA effluent limits for construction stormwater. Since the early 1990s, however, EPA has required permits for construction activities that disturb five or more acres and discharge stormwater to surface waters.[16] In 2003, EPA reduced the threshold for permit coverage to one acre. Covered contractors must develop a Stormwater Pollution Prevention Plan, submit an application for permit coverage—or "Notice of Intent" (NOI) form—and install "Best Management Practices" before disturbing the land.

Compliance with the requirement to obtain stormwater permits is improving. As shown in Figure 3, a nationally representative sample of state data reveals that the percentage of construction projects submitting an NOI increased by 63% from 2003 to 2006. The percentage of total construction projects in compliance, however, is unknown, because EPA has no national data on the number of projects that actually require an NOI.[17]

Figure 3

Trend in NOI Submissions Based on a Sample of States



Note:
Not all construction projects require an NOI, therefore, the percent of projects does not indicate percent in noncompliance.

Source: U.S. Environmental Protection Agency

Colorado Stormwater Excellence Program

An experiment in construction stormwater "self-policing" is generating impressive results in Colorado. Participating companies commit to certain standards for managing stormwater. State-approved inspectors hired by the companies train construction crews and inspect every site monthly. They report findings to the companies, offer guidance on fixing problems, and return to confirm correction. Companies gain confidence that they are achieving compliance. Nearly 800 inspections were conducted during a 2006 pilot project; average improvements for all sites ranged from 60% to 90%.[18]

Waste Generation and Management

Constructing, renovating, and demolishing buildings, roads, bridges, and other structures generates large amounts of debris. Most of it is recoverable and some of it can be reused or recycled. Nevertheless, C&D materials such as concrete, asphalt, wood, drywall, and asphalt shingles are a large component of the waste in the nation's landfills.

EPA made a preliminary estimate that 164 million tons of building-related C&D debris were generated in 2003, up from an estimated 136 million tons in 1996.[19] Approximately 40% of this material was recycled, and the remainder disposed.[20] A preliminary estimate of road surface-related C&D debris generation was 167 million tons in 2003, of which 88% was recycled.[21] EPA is in the process

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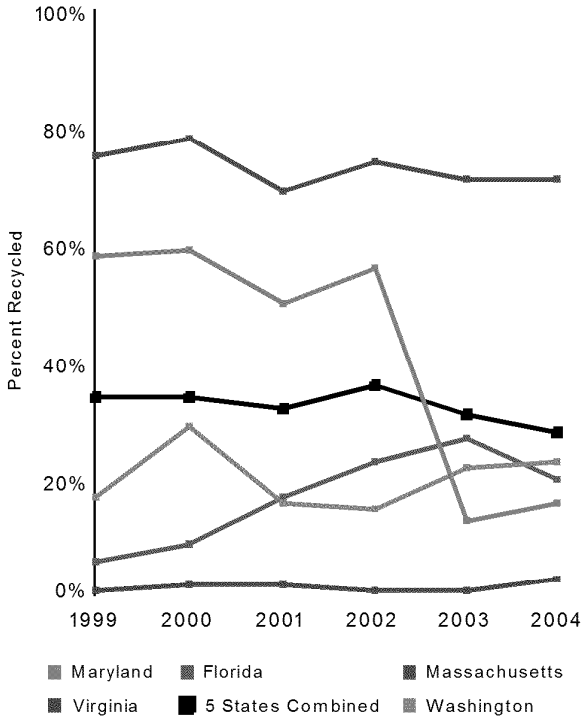
Figure 4

Trends in Construction and Demolition Material Recycling in Five States



Source: U.S. Environmental Protection Agency

Table 1

Uses of Recycled Construction and Demolition Materials

Recycled Construction and Demolition Materials	Recycling Markets
Concrete is crushed, reinforcement bar is removed, and material is screened for size.	Road base
	General fill
	Drainage media
	Pavement aggregate
Asphalt pavement is crushed and recycled into asphalt, either in-place or at a hot-mix asphalt plant.	Aggregate for new asphalt hot mixes
	Sub-base for paved road
After removal of nails, asphalt shingles are ground and recycled into hot-mix asphalt.	Asphalt binder and fine aggregate for hot mix asphalt
Clean, untreated wood can be re-milled, chipped, or ground.	Feedstock for engineered particle board
	Boiler fuel
	Recovered lumber re-milled into flooring
	Mulch and compost
	Animal bedding
Drywall is typically ground or broken up, and the paper removed.	Gypsum wallboard
	Cement manufacture
	Agriculture (land application)
Metal is melted down and reformed.	Metal products
Cardboard is ground and used in new pulp stock.	Paper products

Diverting Materials Through Reuse and Recycling

Turner Construction, one of the largest construction companies in the United States, joined EPA's Climate Leaders program in 2007. Turner has a policy to divert construction waste on all projects through reuse and recycling. Substituting reused and recycled materials for virgin materials reduces energy consumption and related GHG emissions. Turner set a goal to divert 50%, or 75,000 tons, of C&D materials in 2007. Over the previous two years, Turner's Construction Waste Management Program diverted more than 83,000 tons.[22]

of revising its methodology for counting C&D debris generation and recycling.

Recycling rates vary from state to state. A number of states periodically track C&D debris disposed and recycled, but few states regularly publish the data. Differences in the ways states count disposal and recycling limit the usefulness of comparisons among states. C&D debris recycling data for five states are shown in Figure 4 above.[23]

Asphalt pavement is heavily recycled. Construction contractors commonly crush and recycle old asphalt back into pavement. This produces large energy savings because of the energy-intensive process of creating new asphalt binder from oil. Estimates suggest that if all used concrete and asphalt pavement generated annually in the United States were recycled, it would save the energy equivalent of one billion gallons of gasoline, the equivalent of removing more than one million cars from the road.[24] When recycling markets and facilities are nearby, recycling can also reduce material hauling and disposal costs.[25] Table 1 illustrates various uses of recycled C&D materials.[26]

Hazardous Waste Management

Two hundred and twenty facilities reported 17,000 tons of hazardous waste generated to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) in 2005.[27] About half of the hazardous waste reported was managed through treatment or destruction, while the other half was disposed. Lead was the predominant hazardous waste type reported (83%), likely due to the removal of old lead paint. With fewer than 0.1% of all construction establishments reporting, these results may not be representative of the sector.[28]

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Additional Environmental Management Activities

Green Building Practices[29]

Several types of certification systems now are available to rate green buildings. Of them, the U.S. Green Building Council's (USGBC) Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ has the most data available.[30]

Construction contractors have influence on whether and how a building earns LEED credits; 22 out of the 69 possible credits have some relationship to construction activities.[31] For example, one prerequisite is a site plan to reduce air, water, and soil pollution from construction activities; projects receive points for practices such as material salvaging and recycling. Between 2000 and 2006, the LEED New Construction (NC) credits for which construction contractors often have responsibility grew rapidly, closely tracking the increase in all LEED-certified projects (new construction, existing buildings, and other categories), which went from 5 in 2002, to 960 in the first 8 months of 2007.[32]

Individuals can earn LEED Professional Accreditation through the USGBC. Of the 25,700 professionals who were LEED accredited by 2006, 610 identified themselves as general contractors.[34]

Energy-Saving Green Building

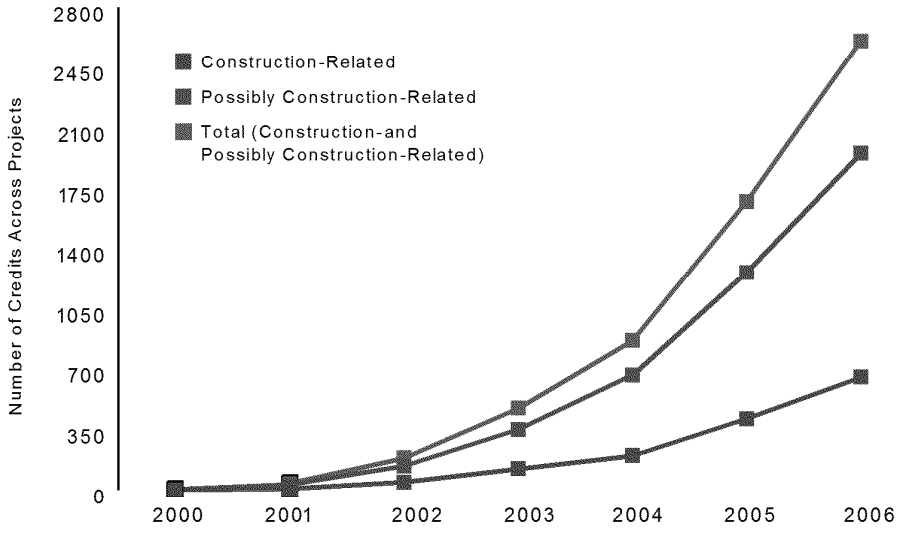
Oscar J. Boldt Construction's regional office in Stevens Point, WI, the company's first LEED project, was a notable success both in design and construction. For example, 79% of the C&D materials generated from construction were recycled, and materials used for construction were high in recycled content and in materials assembled, manufactured, and harvested locally. The building also incorporated numerous environmental improvements, such as energy-saving configurations and equipment that reduced energy use by 58%, resulting in energy costs amounting to only 4% of the building's total operating costs and annual savings of more than $31,000.[33]

Environmental Management Systems

An environmental management system (EMS) is a set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency. Few construction companies operate with an EMS, but more are considering them. In 2004, AGC prepared EMS guidelines and offered training seminars for construction contractors. Since then, the use of EMS appears to be increasing. An AGC survey in 2005 revealed that 13 member companies were developing or operating with an EMS. In 2006, AGC reported the number had grown to 30.[35]

Figure 5

Total LEED-New Construction Credits Received by Construction Contractors



Source: U.S. Green Buildings Council

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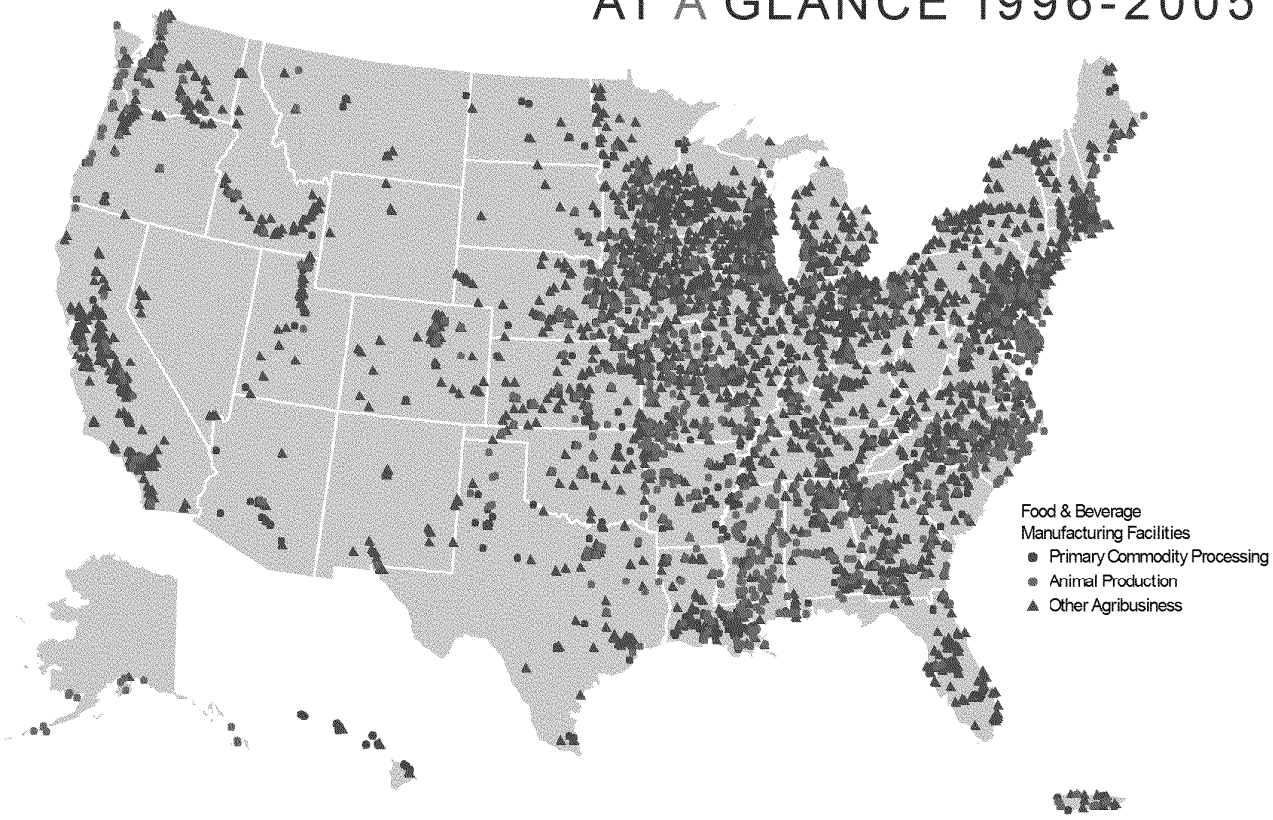
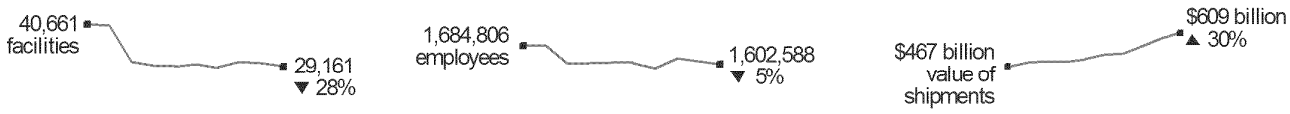
fooD & Beverage manufaCturing

AT A GLANCE 1996-2005[1]





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Latest Environmental Statistics[2]

Energy Use: 1.2 quadrillion Btu

Emissions of Criteria Air Pollutants: 454,000 tons

Releases of Chemicals Reported to TRI: 164.7 million lbs.

- air emissions: 50.4 million lbs.
- Water Discharges: 94.3 million lbs.
- Waste Disposals: 20 million lbs.
- *Recycling, Energy Recovery, or Treatment: 543 million lbs.*

Hazardous Waste Generated: 3,100 tons

Hazardous Waste Managed: 2,400 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

Food & Beverage Manufacturing facilities use agricultural commodities as inputs for producing feedstuffs, food ingredients, or byproducts for industry or pharmaceutical applications. The sector contains three subsectors: primary commodity processing facilities, which perform the first stage of processing for all grains and oilseeds; animal production facilities, which process livestock for food, excluding the raising of livestock on farms; and other food production facilities.

In terms of value of shipments (VOS), the sector represents 13% of all U.S. manufacturing shipments.[3]

Energy Use

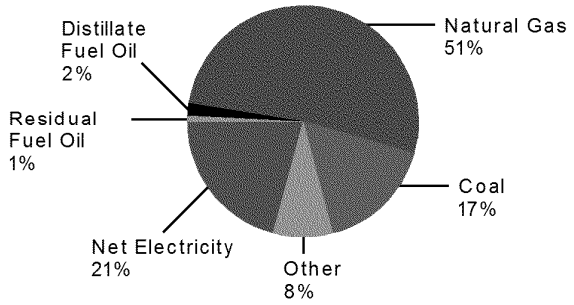
Figure 1 shows the fuels used for energy in the sector in 2002, totaling 1.2 quadrillion Btu. The percentage of energy derived from coal increased during the period covered by this report, coinciding with rising prices for natural gas.[4]

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in raw materials and fuels, and can also be generated in byproducts or end products.

Figure 1
Fuel Use for Energy 2002

Total: 1.2 quadrillion Btu



Notes:
1. Net electricity is an estimation of purchased power and power generation onsite.
2. Other is net steam (the sum of purchases, generation from renewables, and net transfers) and other energy that respondents indicated was used to produce heat and power.

Source: U.S. Department of Energy

Innovative Animal Processing Alternative Energy Source

Most new beef and pork slaughter plants have covered anaerobic lagoons, particularly if they treat and discharge their own wastewater. As of 2006, 10 of these 25 beef and pork first processing plants that directly discharge wastewater are capturing methane (CH_4) from covered lagoons to use as fuel, which typically reduces a packing plant's need for natural gas by about 15%.[5]

Air Emissions Reported to TRI

In 2005, 1,195 facilities in the sector reported 50.4 million absolute lbs. of air emissions to TRI. The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. HAPs accounted for 66% of these emissions. Between 1996 and 2005, absolute TRI-reported air emissions declined 33%, as shown in Figure 2a. As shown in Figure 2b, when normalized by the value of shipments, air emissions decreased 38%, largely due to sector-wide reductions of two chemicals, n-hexane and ammonia. Primary commodity processing facilities accounted for 65% of these emissions, and animal production facilities accounted for 14% of the emissions.[6]

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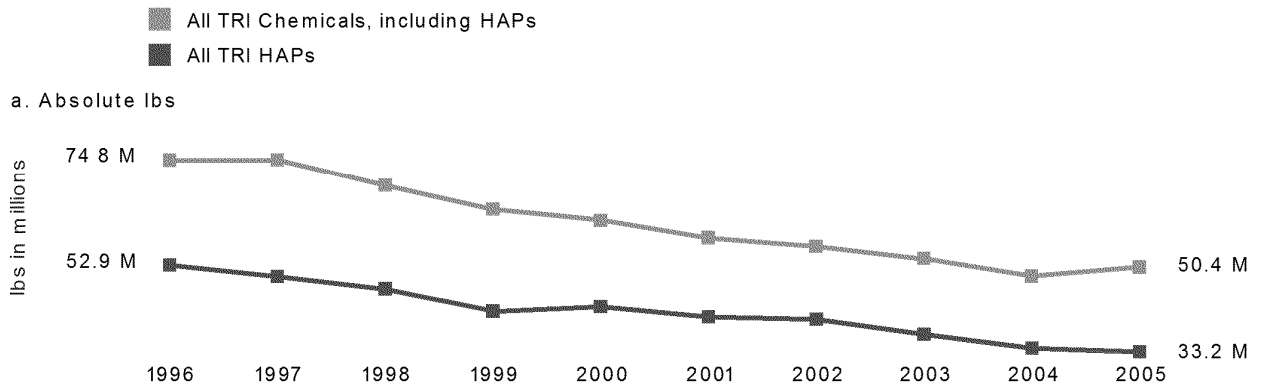
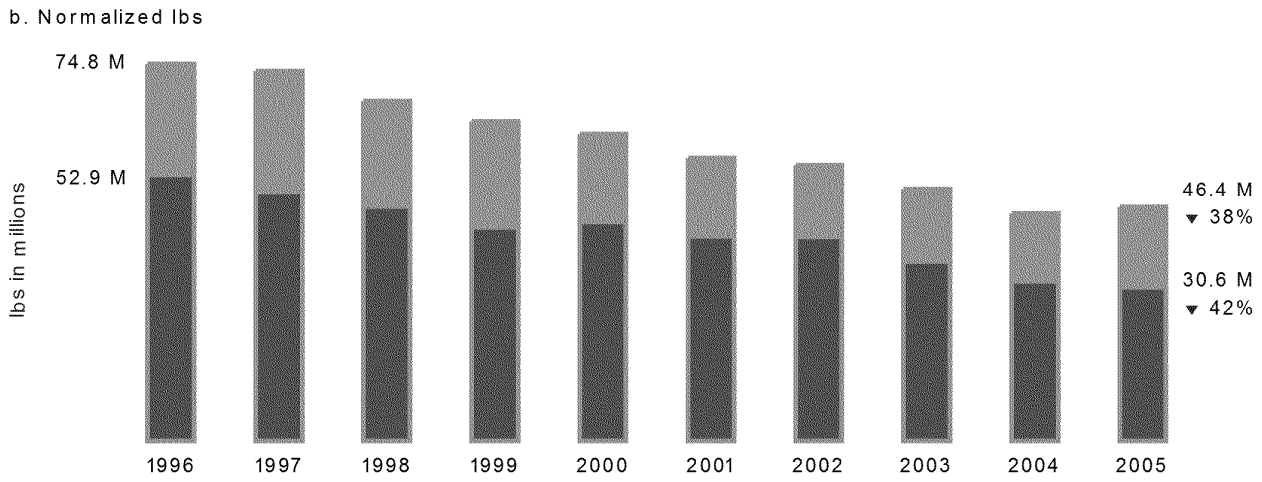
Figure 2

Air Emissions Reported to TRI 1996–2005





Note:
Normalized by annual value of shipments.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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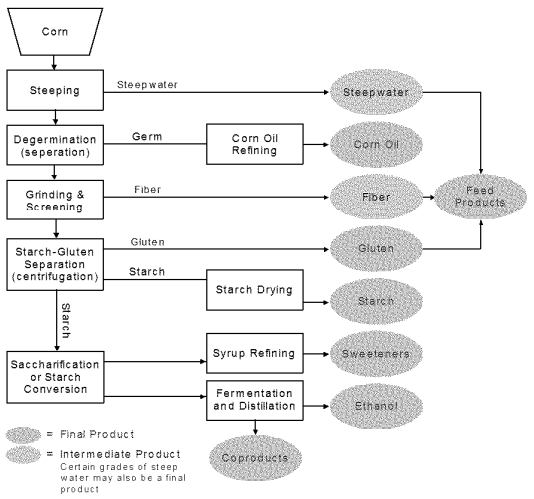
Improving Corn Refining Energy Efficiency

Corn refining is an energy-intensive industry that processes corn into sweeteners, starches, oils, feed, and ethanol. The variety of products obtained from corn is illustrated below. Since 2003, EPA's ENERGY STAR® program has worked with member companies of the Corn Refiners Association to implement best energy management practices and develop a sophisticated energy performance benchmarking tool. Using this comparative metric, companies can set goals for improved energy efficiency. EPA recognizes plants in the top quartile of energy performance with the ENERGY STAR label. Three plants earned ENERGY STAR awards in 2006, saving an estimated 2.3 trillion Btu of energy and avoiding carbon dioxide (CO_2) emissions of 0.15 million metric tons annually.[7]



Source: U.S. Environmental Protection Agency

N-hexane and ammonia are used as solvents to extract specific properties of grains and oilseeds for use in food processing and industrial applications, such as in the production of corn oil and soybean oil. The industry increased its efficiency in using these two chemicals and has increased the percentage of chemicals that are recycled.

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. The sector's Toxicity Score increased by 70% from 1996 to 2005 when normalized by the sector's annual VOS. The increased Toxicity Score from 1999 to 2002 was due to air emissions of three chemicals: acrolein, polycyclic aromatic compounds (PAC), and chlorine.[8]

Acrolein is produced when fats and oils are heated to a high temperature either during oilseed processing or during food cooking in oil. PAC includes a variety of compounds formed during the preservation and processing of food. Chlorine is used in various applications involving food safety and sanitation.

Several factors caused the three-year bubble apparent in Figure 2c. A facility in the Primary Commodity Processing subsector started reporting large releases of acrolein in 2000, and two other subsectors started reporting releases in 2001. Also in 2000, EPA lowered the reporting threshold for PAC to 100 pounds, resulting in an additional 61 facilities reporting releases of these chemicals. Finally, a facility reported a large release of chlorine in 1999. The combination of these factors contributed to the four-year "bubble" in the sector's Toxicity Score shown in Figure 2c.

Table 1 presents the top TRI-reported chemicals emitted to air by the sector based on three indicators. Each indicator provides data that environmental managers, trade

Table 1
Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Acetaldehyde[3]	2,048,000	5%[4]	24
Acrolein	24,000	25%	2
Ammonia	11,956,000	2%	408
Hydrochloric Acid	4,224,000	4%	34
Lead	17,000	2%	68
Methanol	3,002,000	<1%	38
N-Hexane	22,027,000	1%	86
Nitrate Compounds	2,637,000	<1%	14
Polycyclic Aromatic Compounds	59,000	10%	48
Sulfuric Acid	1,774,000	37%	22
Zinc	15,000	<1%	43
Percentage of Sector Total	**95%**[5]	**86%**[6]	**51%**[7]

Notes:
1. Total sector air emissions: 50.4 million lbs.
2. 1,195 total TRI reporters in the sector.
3. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
4. Red indicates that the chemical is one of the top five chemicals reported in the given category.
5. Chemicals in this list represent 95% of the sector's air emissions.
6. Chemicals in this list represent 86% of the sector's Toxicity Score.
7. 51% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

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associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. N-hexane and ammonia were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005.
2) Percentage of Toxicity Score. The top chemicals based on Toxicity Score included sulfuric acid and acrolein.
3) Number of Facilities Reporting. Ammonia was the chemical reported by the greatest number of facilities, with one-third of the almost 1,200 TRI filers in the sector reporting ammonia air emissions.

Criteria Air Pollutants

Table 2 shows CAP and volatile organic compound (VOC) emissions in 2002, representing emissions from almost 2,500 facilities.[9]

Sixty-three percent of the reported CAP emissions are the result of onsite energy production at Food & Beverage Manufacturing facilities. Process heating and cooling systems account for more than 75% of the sector's energy use and are necessary to meet food safety regulations. About 12% of energy used in this sector supports general facility functions, such as heat, ventilation, and lighting. Energy-intensive processes are required for sugar, malt beverage, corn milling, and meat and poultry processing.[10]

Table 2

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	116,000
NO_X	76,000
PM_{10}	50,000
$PM_{2.5}$	30,000
CO	112,000
VOCs	100,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Greenhouse Gases

Food & Beverage Manufacturing facilities emit GHGs directly from fossil fuel combustion and from non-combustion processes. Non-combustion activities include CH_4 emissions from onsite wastewater treatment at meat, poultry, fruit, and vegetable processing facilities. The generation of electricity purchased by food and beverage manufacturers also emits GHGs.

Reducing Emissions From Food Manufacturing

Frito-Lay, a Climate Leaders member, reported the company's GHG emissions for 2002 and subsequent years. The company set a goal—it reports being on track to achieve that goal—to reduce emissions by 14% per pound of production from 2002 to 2010. The company has focused on improving energy efficiency through, for example, implementing heat recovery projects for boiler stack gases, ovens, and fryers.[11]

Ten Food & Beverage Manufacturing facilities are members of EPA's Climate Leaders program, an industry-government partnership that works with companies to develop long-term, comprehensive climate change strategies.[12] These facilities set GHG reduction goals to be achieved over 5–10 years in either absolute pounds or GHG intensity per production unit.

Water Use and Discharges

Water is integral to food and beverage production processes as an ingredient in products, such as beverages; as a mixing and seeping medium in food processing; and as a medium for cleaning and sanitizing operations. Water conservation is an option for food and beverage production; however, special consideration often is needed to ensure product safety. Water sources include onsite wells, surface water with pre-treatment, and municipal drinking water systems. Table 3 provides water intensity estimates for selected products.

Table 3

Estimated Water Intensity of Selected Products

Product	Gallons per Ton of Product
Beer	2,400 to 3,840
Bread	480 to 960
Meat Packing	3,600 to 4,800
Milk Products	2,400 to 4,800
Whiskey	14,000 to 19,200

Source: Metcalf and Eddy

Every facility discharging process wastewater directly to waterways must apply for a National Pollutant Discharge Elimination System (NPDES) permit. The permits typically set numeric limits on specific pollutants and include monitoring and reporting requirements. Regulated

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Water Stewardship

- The Farmland Foods subsidiary of Smithfield Foods won the 2006 Illinois Governor's Pollution Prevention Award for water conservation at its facility in Monmouth, IL. The plant retrofitted its water cooling system with closed-loop technology using ethylene glycol, saving an estimated 22 million gallons of water annually.[13]
- Coca-Cola's water stewardship program includes water efficiency targets, a goal to return process water to the environment at a level that supports aquatic life by 2010, and support of watershed protection and community water programs. Coca-Cola reported a 3% improvement in water efficiency in 2006 compared to 2005, and a 19% improvement in efficiency and 6% decrease in total water used since 2002.[14]
- Nestlé Purina's wet pet food facility in Jefferson, WI, improved its water management and processes, lowering water use for cooling and steam production. The changes save more than 20 million gallons of water annually, reducing water use per ton of product by 7%. The facility also reduced its annual use of natural gas by 20 trillion Btu, with corresponding emissions reductions.[15]

pollutants and the associated limits vary depending on the type of manufacturing process (such as grain mill, fats and oils, or meat products manufacturing), but most frequently include total suspended solids, pH, biological oxygen demand, ammonia, and total nitrogen.[16]

Two-hundred thirty Food & Beverage Manufacturing facilities reported water discharges of TRI chemicals in 2005, totaling 94.3 million lbs.[17] Nitrate compounds dominated water discharges, accounting for more than 99% of the lbs. discharged. Although reported total nitrate compound discharges increased more than 100% from 1996 through 2005, the number of reporting facilities also more than doubled (43 to 91), indicating that more facilities met the TRI reporting thresholds. Seventy-two percent of these discharges were from animal production facilities, while primary commodity processing facilities accounted for 14%.[18]

EPA promulgated effluent guidelines for meat and poultry producers in 2004, setting technology-based limits on a number of pollutants, including ammonia and nitrogen. As states and EPA regions incorporate these regulations into NPDES permits, operators will be required to upgrade onsite water treatment to comply with the more stringent effluent limits.

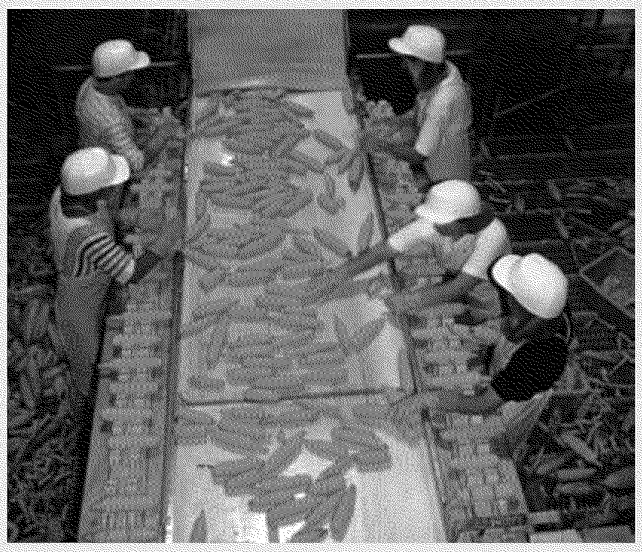
In addition to being regulated for direct discharges and for discharges to Publicly Owned Treatment Works, facilities with materials exposed to precipitation are regulated for stormwater runoff, usually under a general permit providing sector-specific limits. Depending on the type of facility, stormwater requirements for Food & Beverage Manufacturing facilities may include effluent limits on total suspended solids, biochemical or chemical oxygen demand, and nitrate/nitrite nitrogen.[19]

Waste Generation and Management

Wastes generated by the sector vary greatly by facility and process. Production of commodities such as grains, dairy, fruits and vegetables, and food processing have different material and waste management issues, such as pesticide residue, vegetable trim, and used packaging.

Hazardous Waste Management

In 2005, 82 Food & Beverage Manufacturing facilities reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 3,100 tons of hazardous waste. At 44% and 42% of the total, respectively, intermittent events (such as discarding off-spec products) and primary production processes were the largest sources of hazardous waste. Facilities reported managing 2,400 tons of hazardous waste, with 50% managed through destruction or treatment and 41% managed through reclamation and recovery.[20]



Waste Management Reported to TRI

In 2005, 1,195 Food & Beverage Manufacturing facilities reported managing 707.8 million absolute lbs. of TRI chemicals in waste. When normalized by value of shipments, this quantity represented 54% more than 1996 quantities, indicating that more waste was generated per dollar of product sold.

Figure 3 shows how the sector managed this TRI waste. In 2005, 39% was recycled, 37% was treated, 23% was

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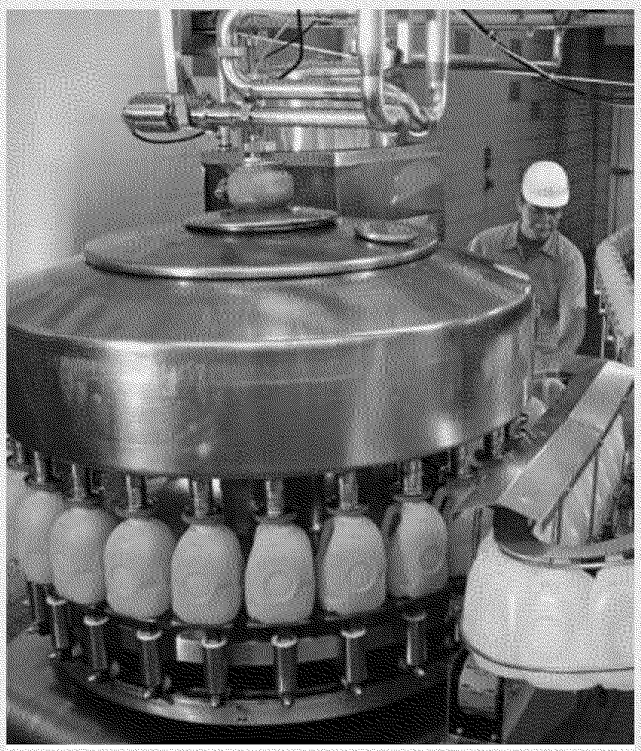


disposed or released to air or water, and less than 1% was recovered for energy use. The pounds managed under each management activity increased over the time period presented. The greatest increase was in recycling, although the annual quantities reported as recycled fluctuated dramatically between 110,000 lbs. and 850,000 lbs.[21]

Of the TRI waste managed in 2005, 52% was reported by primary commodity processing facilities, while animal production facilities accounted for 28%. Over the decade, waste managed by these subsectors increased by 84% and 87%, respectively.[22]

The quantity of waste that Food & Beverage Manufacturing facilities disposed to land, as reported to TRI, increased from 9.1 million lbs. in 1996 to 20 million lbs. in 2005. When normalized by the value of annual shipments, this represented a 102% increase. As shown in Table 4, nitrate compounds remained the chemicals disposed in the greatest quantity over the 10-year period, accounting for about two-thirds of disposals, and were one of the chemicals most frequently reported as disposed for this sector. Ammonia was also one of the chemicals disposed in the greatest quantity and was the second most frequently reported chemical disposed for this sector.[23]

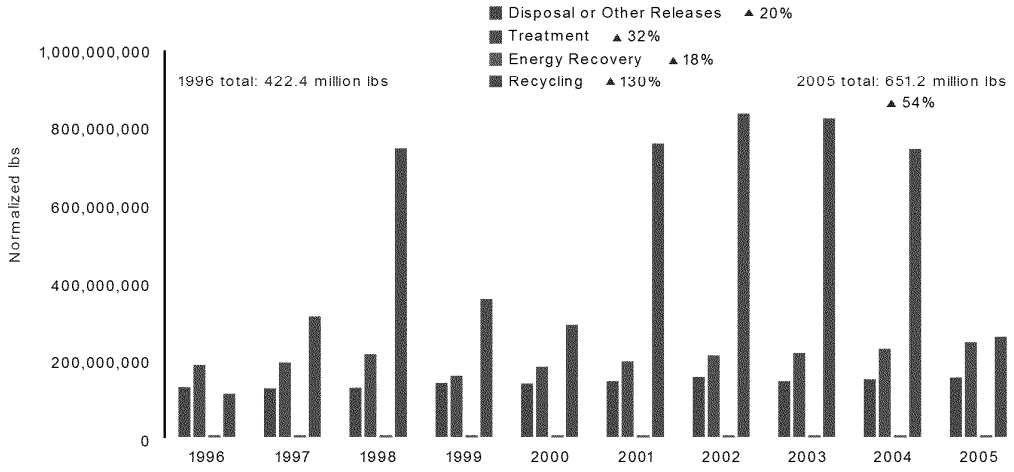
Additional Environmental Management Activities

Supply Chain Sustainability

Sector manufacturers are increasingly working with their suppliers to improve the environmental sustainability of agricultural production. Traditionally, their efforts have focused on reducing pesticide use through Integrated Pest Management. Projects now include improving water quality as well and reducing soil erosion.

Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual value of shipments.
2. Disposal or other releases include air emissions, water discharges, and land disposals.
3. The fluctuation in recycling was due to the reports filed by a single facility.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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Table 4

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Ammonia	1,350,000[3]	136
Barium	1,697,000	16
Lead	92,000	37
Manganese	519,000	19
Nitrate Compounds	13,869,000	154
Nitric acid	369,000	29
Zinc	690,000	36
Percentage of Sector Total	**93%**[4]	**26%**[5]

Notes:
1. Total sector disposals: 20 million lbs.
2. 1,195 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 93% of the sector's disposals.
5. 26% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Environmental Conservation

In 1998, Unilever developed its good agricultural practice guidelines for palm oil, tea, tomatoes, peas, and spinach, and promoted them to food growers to track progress with 11 sustainable agriculture indicators, such as water, energy, pesticides, and biodiversity. In 2007, the company established guidelines for tea growers and committed to purchase all of its tea from sources meeting those standards.[24]

Crop Chemicals Reductions

Since 2004, SYSCO has worked with fruit and vegetable suppliers to reduce the use of farm chemicals and fertilizers through pest management techniques and best management practices for fertilizer application. Suppliers report using 100,000 fewer pounds of pesticides and 2.2 million fewer pounds of fertilizers, while improving produce quality and better protecting water quality.[25]

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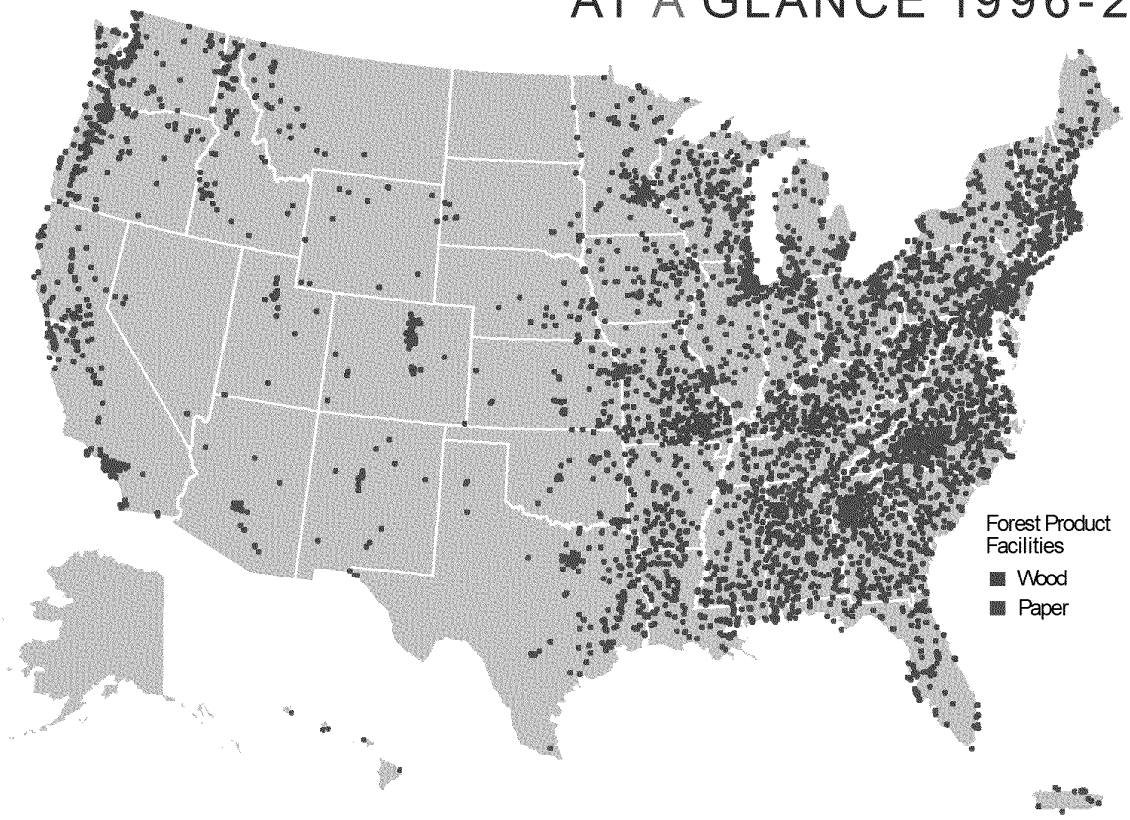
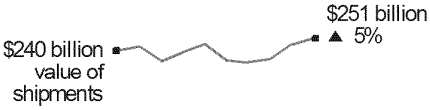
forest ProDuCts

AT A GLANCE 1996-2005[1]





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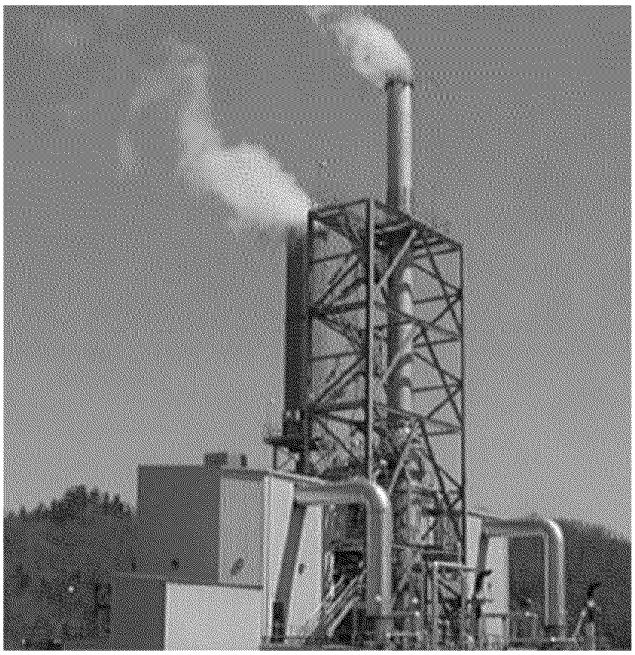


Latest Environmental Statistics[2]

Energy Use: 2.7 quadrillion Btu

Emissions of Criteria Air Pollutants: 1.5 million tons

Releases of Chemicals Reported to TRI: 255.7 million lbs.

- airemissions: 206 million lbs.
- Water Discharges: 20.5 million lbs.
- Waste Disposals: 29 million lbs.
- *Recycling, Energy Recovery, or Treatment: 1.4 billion lbs.*

Hazardous Waste Generated: 136,000 tons

Hazardous Waste Managed: 396,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Forest Products sector includes firms that manufacture wood pulp, paper, paperboard, and wood products such as lumber.[3]

- Some facilities of the pulp and paper industry process raw wood fiber or recycled fiber to make pulp and/or paper. Other facilities use these primary materials to manufacture specialized products such as paperboard boxes, writing paper, and sanitary paper.
- Companies in the lumber and wood products industry cut timber and pulpwood, mill raw materials into lumber and building materials, and manufacture finished articles such as wood panels.

Forest Products is the third-largest manufacturing sector in consumption of fossil fuel energy and is a major user of water.[4]

Although the sector is energy intensive, it has a high level of cogeneration and use of biomass to produce energy.

The sector accounts for nearly 6% of the total value of shipments (VOS) in U.S. manufacturing.[5]

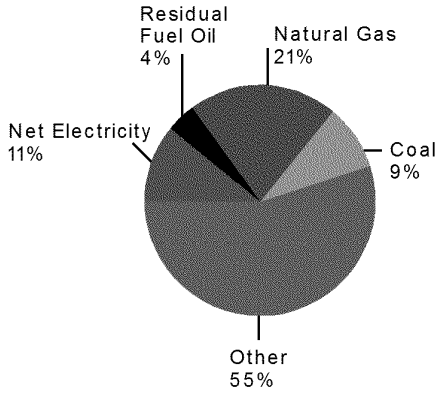
Energy Use

Making paper is energy and water intensive. A significant amount of energy is needed, for example, to remove water from the dilute fiber slurry that is the beginning stage of making paper from pulp. The recovery furnaces that regenerate the chemicals that cook wood chips to produce pulp also require large quantities of energy. The pulp and paper portion of the sector is especially energy intensive. In

Figure 1

Fuel Use for Energy 2002

Total: 2.7 quadrillion Btu



Notes:
1. Other is primarily generation from renewables and net steam (the sum of purchases, generation from renewables, and net transfers).
2. Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

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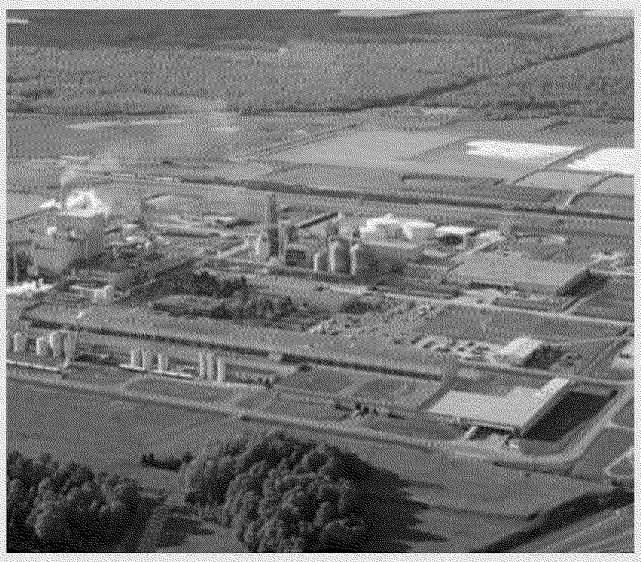

2002 the manufacture of wood products counted for 375 trillion Btu, or about 14% of the sector's energy use; 2,361 trillion Btu, or 86%, was attributable to pulp and paper mills.[6]

Renewable fuels account for the majority of energy use at Forest Products facilities, which represent 93% of all U.S. manufacturing in use of wood byproduct fuels, such as bark, wood waste, and spent pulping liquor.[7] Bark and wood waste are burned in power boilers to produce electricity and steam for a facility. Pulp manufacturing facilities burn spent pulping liquor, a solution of wood lignin (an organic polymer) from process chemicals, in recovery boilers to produce steam and regenerate the process chemicals. Figure 1 shows fuel used for energy in 2002 in the sector.

The American Forest & Paper Association (AF&PA) and U.S. Department of Energy (DOE) formed the Agenda 2020 Technology Alliance in 1994 to cut energy use and emissions through innovations in technology, manufacturing processes, and market development. The Alliance, now independent of DOE, partners with governments and local and international organizations; shares information on new advances such as biorefineries that produce fuels from wood; and partners on efforts including research and development into renewable, bio-based products such as fibers, fuels, and chemicals.[8]

Many facilities have achieved long-term reductions in energy intensity through process efficiencies and cogeneration.[9] Cogeneration, or combined heat and power (CHP), increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source. Pulp and paper facilities are leaders in using cogenerated energy. About 89% of the electricity generated at paper mills was cogenerated in 2002. Typically, 99% of the electricity generated at wood products facilities is cogenerated.[10] The sector overall produced 37% of all cogenerated energy in manufacturing in 2002, second only to the Chemical Manufacturing sector. Forest Products facilities have opportunities for short-term fuel switching, although fuels with fewer emissions or greater efficiency can be more costly.[11]

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). Fuel combustion and manufacturing contribute to air emissions from this sector. In general, the "toxic chemicals" tracked by TRI are found in the raw materials and fuels used in the manufacturing process, and can be generated in byproducts or end products. Toxic chemicals from this sector may be generated and emitted to the environment during wood processing, chemical recovery, and papermaking operations in pulp and paper mills and during drying and pressing operations in wood products plants. CAPs and GHGs also are generated as combustion byproducts from onsite energy production and from some production processes and other activities.

Air Emissions Reported to TRI

In 2005, 1,144 facilities in the sector reported to TRI 206 million absolute lbs. of air emissions. Between 1996 and 2005, absolute TRI-reported air emissions declined by 24%, as shown in Figure 2a. When normalized by the sector's VOS over the period, air emissions decreased 12%, as seen in Figure 2b.[12] While these 1,144 facilities only accounted for about 5% of Forest Products facilities, this number includes virtually all pulp and paper mills, as well as the larger and more chemically intensive wood products manufacturing facilities.

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories. Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c.

The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. Regulations regarding combustion byproducts, issued in 1997, required pulp and paper mills to add

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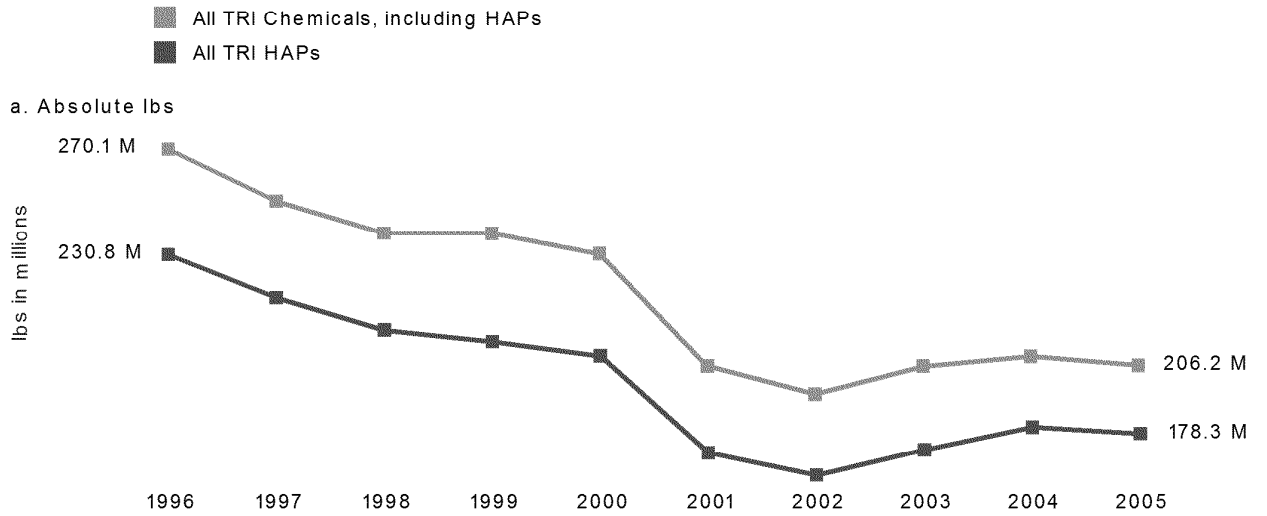
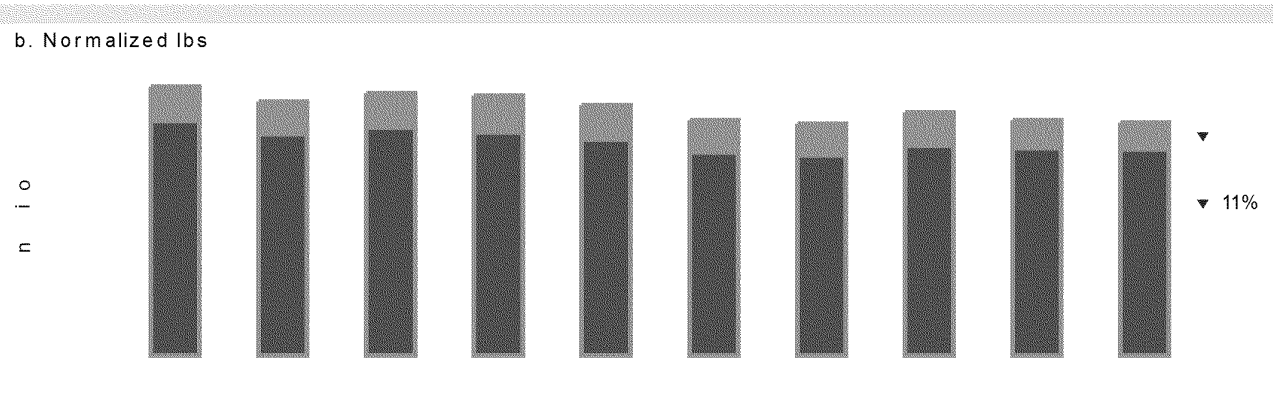
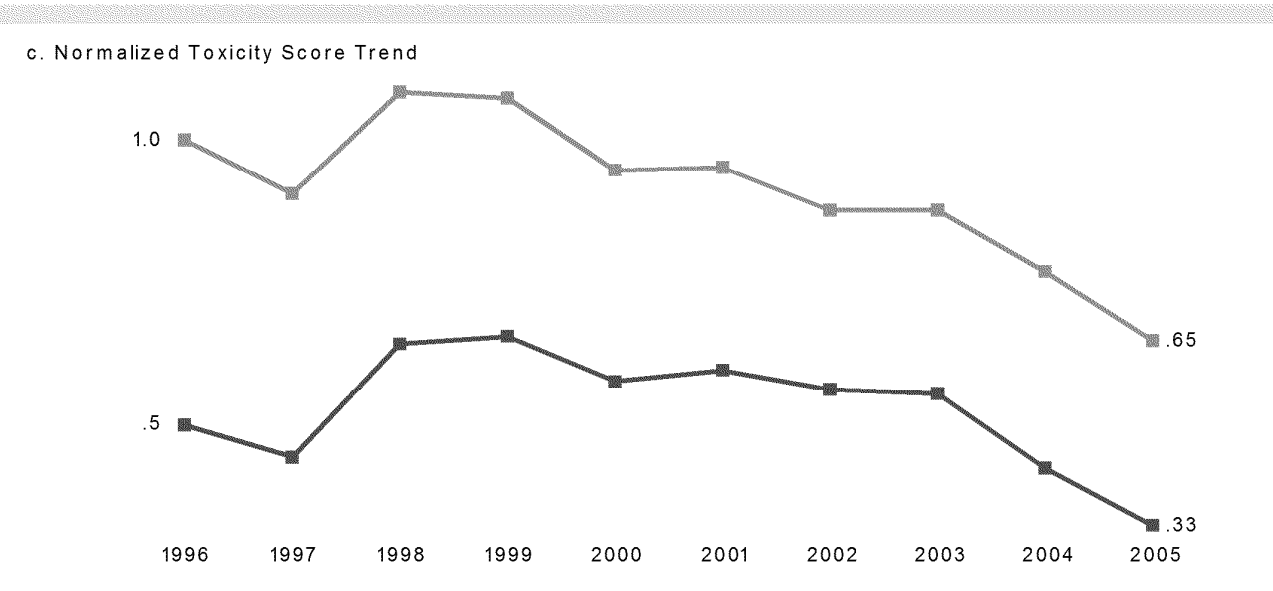
Figure 2

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual value of shipments.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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emission controls to the pulping, pulp washing, and pulp bleaching processes. Eighty-six percent of pulp and paper TRI air emissions are also HAPs, so air emission trend lines for all TRI chemicals and for HAPs declined similarly over the past decade.[13]

Absolute TRI air emissions decreased 24% since 1996. When normalized by VOS, absolute emissions fell 12%.[14] Toxicity Scores, when normalized by VOS, decreased 35% over this period, indicating that the falling Toxicity Scores reflect an environmental performance improvement, rather than simply a decline in production levels.[15]

Table 1 presents the top TRI-reported chemicals emitted to air by the sector based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Methanol (formed in the pulping of wood chips) and ammonia (formed in the chemical recovery process) were the top-ranking chemicals based on pounds emitted to air in 2005.

Table 1

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Acetaldehyde[3]	8,518,000[4]	4%	156
Acrolein	53,000	11%	6
Ammonia	16,769,000	1%	170
Chlorine Dioxide	546,000	11%	78
Dioxin and Dioxin-Like Compounds	<1	<1%	272
Formaldehyde	6,390,000	9%	217
Hydrochloric Acid	15,979,000	3%	136
Lead	43,000	1%	535
Manganese	184,000	15%	148
Methanol	126,057,000	<1%	362
Polycyclic Aromatic Compounds	96,000	3%	205
Sulfuric Acid	7,886,000	32%	99
Toluene	10,120,000	<1%	175
Percentage of Sector Total	**93%**[5]	**90%**[6]	**76%**[7]

Notes:
1. Total sector air releases: 206 million lbs.
2. 1,144 total TRI reporters in the sector.
3. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
4. Red indicates that the chemical is one of the top five chemicals reported in the given category.
5. Chemicals in this list represent 93% of the sector's air emissions.
6. Chemicals in this list represent 90% of the sector's Toxicity Score.
7. 76% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

2) Percentage of Toxicity Score. Top-ranked chemicals based on Toxicity Scores include sulfuric acid from coal and oil burning in boilers, manganese from burning wood and coal, and chlorine dioxide from pulp bleaching. Together these chemicals accounted for more than half of the sector's overall Toxicity Score in 2005.

3) Number of Facilities Reporting. Lead from fossil fuel boilers, and methanol, were the most frequently reported chemicals. Two-thirds of facilities reporting TRI air emissions reported emissions of at least one of these two chemicals.

When wood and coal are burned, manganese is either emitted or partitioned to ash and subsequently landfilled. In 1997, EPA clarified TRI reporting requirements regarding combustion byproducts. Subsequently, metal byproducts from combustion of coal and oil are considered "manufactured" and therefore included in the reporting threshold calculation. This clarification resulted in new manganese reporting for many facilities and, thus, an increase in the amount reported to TRI.[16]

Criteria Air Pollutants

Table 2 shows CAP and volatile organic compound (VOC) emissions from facilities in the Forest Products sector for 2002.

Table 2

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	366,000
NO_X	277,000
PM_{10}	118,000
$PM_{2.5}$	76,000
CO	460,000
VOCs	245,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

The major CAP emissions from Forest Products manufacturing—carbon monoxide (CO), nitrogen oxides (NO_X), and sulfur dioxide (SO_2)—primarily are generated in combustion sources such as power boilers. NO_X and SO_2 can be transported over long distances and contribute to ozone and particulate emissions in urban areas that are downwind of facilities.

More recent data collected by AF&PA indicate a 12% decrease in SO_2 emissions per ton of production from 2002 to 2004, and a 9% decrease of NO_X emissions per ton of production. These reductions were gained through more sophisticated process controls, additional pollution control equipment, and use of low-sulfur fuels.[17]

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Greenhouse Gases

The sector's GHG profile is diverse. It includes direct and indirect carbon dioxide (CO_2) emissions from manufacturing operations. Forests also serve as carbon sinks, absorbing CO_2 from the atmosphere through growth. When harvested, carbon in the trees is transferred to forest products, which can lead to long-term storage of the carbon as in structures such as houses or in disposal sites.[18]

AF&PA participates in Climate VISION, a DOE-industry voluntary partnership to reduce GHG intensity, which is the ratio of GHGs to economic output. AF&PA member companies manufacture more than 80% of the paper and approximately half the wood products produced in the United States. Under Climate VISION, AF&PA members have committed to reduce GHG intensity by 12% by 2012 relative to a 2000 baseline.[19]

AF&PA reported that its members' direct GHG emissions from fossil fuel use and process emissions were 51.4 million metric tons of CO_2 equivalent ($MMTCO_2E$) in 2004, down from 61.2 $MMTCO_2E$ in 2000, and that GHG emissions from the generation of electricity purchased were 26.2 $MMTCO_2E$ in 2004, down from 26.8 $MMTCO_2E$ in 2000.[20] Table 3 presents the estimated GHG emissions for the sector; the estimates did not factor in carbon sequestration or GHG emissions from wastewater treatment.[21]

Table 3

Estimated GHG Emissions 2004

	Million Metric Tons of Carbon Dioxide Equivalent
Fossil Fuel Combustion and Process Emissions	51.4
Electricity[1]	26.2
Total	**77.6**

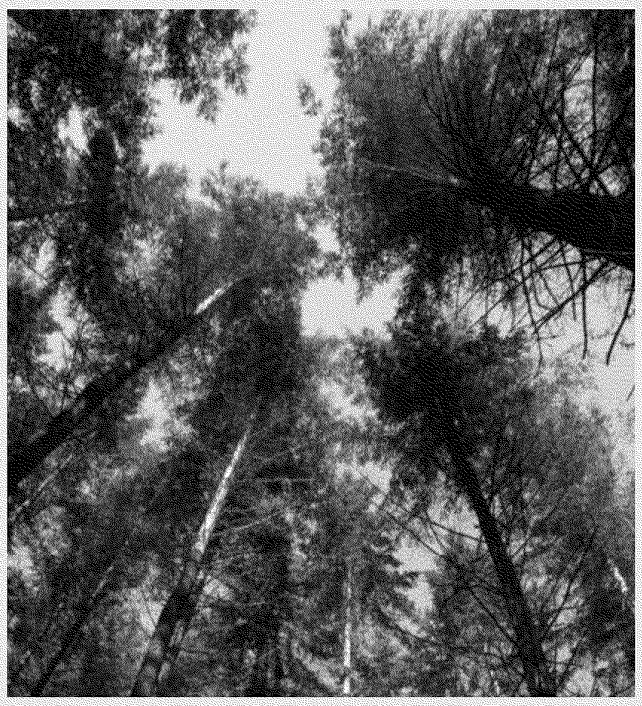
Note:
1. Indirect emissions from generation of purchased electricity.

Sources: American Forest & Paper Association, National Council for Air and Stream Improvement

Water Use and Discharges

As noted above, pulp and paper making is water-intensive. In pulp bleaching, for example, bleaching occurs in stages and the pulp must be washed between the stages. Many facilities are recycling water where possible and attempting to reduce the need for water.

Wastewater discharges are a major focus for this sector. In 2005, 370 Forest Products facilities reported water discharges of TRI chemicals totaling 20.5 million lbs., an 18% increase since 1996, when normalized by VOS over this period.[22] The predominant TRI chemicals discharged in



2005 included nitrate compounds, methanol, manganese, and ammonia. Combined, these chemicals accounted for 91% of the total TRI chemicals discharged to water that year. Pulp and paper mills accounted for almost all of the sector's water discharges.[23]

Forest Products manufacturing facilities discharge wastewater either to Publicly Owned Treatment Works (POTWs) or directly into waterways. Every facility discharging process wastewater directly to waterways must apply for a National Pollutant Discharge Elimination System permit. The permits typically set numeric limits on specific pollutants and include monitoring and reporting requirements. For facilities in this sector, regulated pollutants and the associated limits vary depending on the product being manufactured. For example, permits for wood-preserving facilities limit their discharges to POTWs of oil and grease, copper, chromium, and arsenic, and limit their discharges to waterways of oil and grease and phenols. Permits for pulp and paper mills limit zinc, among other pollutants, in their POTW and direct discharges.[24] The state of the best and most current discharge control technology, pollutant control technology, and economic feasibility also help determine the quantity or quality of discharge limits.

Pulp and paper mills also discharge effluent that lowers oxygen levels in receiving waters. In 1995, pulp and paper mills discharged approximately four lbs. of biochemical oxygen demand (BOD) per ton produced. In 2002–2004, the BOD of their effluent was 2.6 and 2.8 lbs. per ton produced, respectively.[25] The long-term trend toward reduced BOD is due to improved production processes and wastewater treatment, in response to state and federal regulations. The sector also has reported a significant long-term decrease in total suspended solids (TSS) in its discharges due to improved wastewater treatment, also in response to regulatory requirements.

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Water discharges became a major focus in the 1980s when dioxins were found in waters that received pulp mill effluent. Since then, elemental chlorine bleaching of pulp has been replaced by bleaching processes based on chlorine dioxide, and dioxin pollution has dropped below detectable levels.[26] Current water toxics concerns are discharges of lead and nitrate compounds; lead accounts for the highest toxicity weighting among the water discharges, and nitrates account for more pounds of discharge than other listed toxins. Conventional discharges of concern are TSS and BOD.

In addition to being regulated for direct and POTW discharges, those facilities with materials exposed to precipitation are regulated for stormwater runoff, usually under a general permit that provides sector-specific limits. Stormwater effluent limits are set for TSS, chemical oxygen demand, arsenic, phenols, and metals—zinc, copper, and chromium.[27]

Reducing Water Use

Stora Enso Duluth Paper Mill and Recycled Pulp Mill, in Duluth, MN, reduced water use relative to production by nearly 25% from 2002 to 2006. The facility focused on water reuse and use of previously sewered water. Instead of using fresh water, for example, the facility's retention aid injection system now uses water that had been going to the sewer. With these and other measures, the mill has saved $398,000 over three years.[28]

Waste Generation and Management

Hazardous Waste Management

In 2005, 403 Forest Products facilities reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 136,000 tons of hazardous waste. The number of facilities reporting hazardous waste generation and the quantities reported in this sector were evenly distributed between the wood and paper products subsectors. The predominant source of hazardous waste generation in the sector was ongoing production and service-related processes. The predominant types of hazardous waste reported by the sector in 2005 were F034 (defined as wastewaters, process residuals, preservative drippage, and spent formulations from wood-preserving processes generated at plants that use creosote formulations) and corrosive waste, together representing three-quarters of the total generated wastes.[29] The sector reported managing 396,000 tons of hazardous waste. The difference between wastes generated and waste managed was due to groundwater remediation efforts at two wood products facilities.

Waste Management Reported to TRI

In 2005, the Forest Products sector reported managing 1.7 billion absolute lbs. of TRI chemicals in waste. As shown in Figure 3, when normalized by VOS, the quantity of waste managed by the sector remained relatively steady between 1996 and 2005. In 2005, 15% of the TRI-reported waste was disposed or released, 66% was treated, 12% was recovered for energy, and 6% was recycled. Pulp and paper mills accounted for almost all (95%) of the sector's waste managed.[30] There has been little change in the management methods used by this sector over the last decade.

In 2005, the sector reported disposing 29 million lbs. of TRI chemicals to land, or transferring the chemicals offsite for disposal. As shown in Table 4, manganese accounted for almost half of the total pounds disposed by the sector in waste. Zinc and barium were also disposed in large quantities. Lead was the chemical most frequently reported as disposed, followed by dioxin and dioxin-like compounds.

Table 4
Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Barium	3,638,300[3]	98
Dioxin and Dioxin-Like Compounds	2	204
Lead	587,000	423
Manganese	13,623,400	140
Mercury	1,500	113
Methanol	1,010,700	119
Vanadium	1,397,500	39
Zinc	7,458,600	108
Percentage of Sector Total	**96%**[4]	**43%**[5]

Notes:
1. Total sector disposals: 29 million lbs.
2. 1,144 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 96% of the sector's disposals.
5. 43% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

The sector continues to find ways to recycle waste and process byproducts—for energy production, reuse in new products, agricultural applications, and soil enrichment.[31] Kraft pulping mills burn spent pulping mixtures to generate energy and to recover pulping chemicals. Other wastes, such as wastewater treatment residuals and boiler ash, are increasingly being used as soil amendments. From 2002

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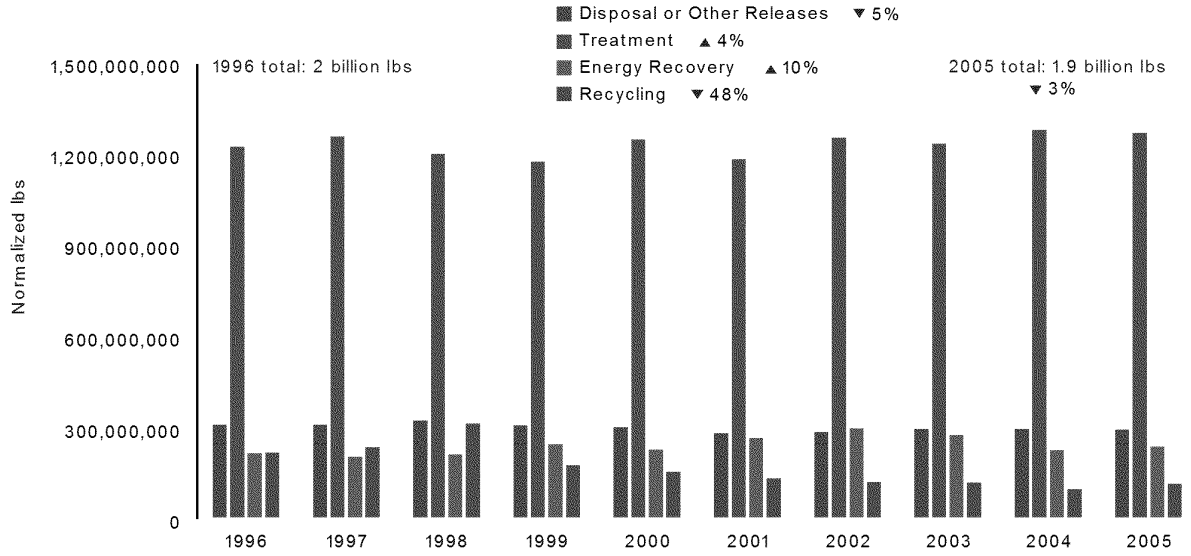
Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual value of shipments.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

to 2004, the proportion of wastewater treatment residuals used for land application increased from 12% to 16%.[32]

The sector's involvement in resource recovery goes beyond its own industrial processes. About 52% of the paper consumed by all users in the United States is recovered for recycling; AF&PA has a goal to raise that percentage to 55% by 2012.[33]

Additional Environmental Management Activities

Many of the technology goals and research of the Agenda 2020 Technology Alliance would also improve environmental performance by reducing water use, finding beneficial uses for process wastes, and improving recycling.[34] Breakthrough technologies that would allow for more concentrated slurries at the beginning of the papermaking process, for example, would save both energy and water. Enhancements in chemical recovery that would either improve or eliminate lime kilns could save substantial amounts of fuel.

Forest biorefineries (described in the "Energy Use" section) could turn what are currently low-value byproducts and fuels into higher value chemicals and fuels. Wood contains three main chemical components: cellulose, hemicellulose, and lignin. Current pulping technology extracts the cellulose, which is used to make paper pulp; the lignin, which is burned for fuel; and the hemicellulose, which converts to certain sugars. The biorefinery would add three new processes. First, hemicellulose would be extracted from chips before pulping and would be converted either to ethanol fuel or other industrial chemicals. Second, boilers that currently burn waste biomass (e.g., bark, waste chips) would instead convert the biomass to syngas, an intermediate product that could then either be burned as a fuel or further converted to a mixture of fuels and chemicals similar to crude oil. Third, the spent pulping liquor containing lignin and pulping chemicals could itself be gasified for fuel, while continuing to recover pulping chemicals for reuse.[35]

These new technologies are at various stages of research and development. New mandates and market opportunities for renewable fuels are prompting accelerated efforts to commercialize forest-based biofuels, and production plants may start up in the next few years.

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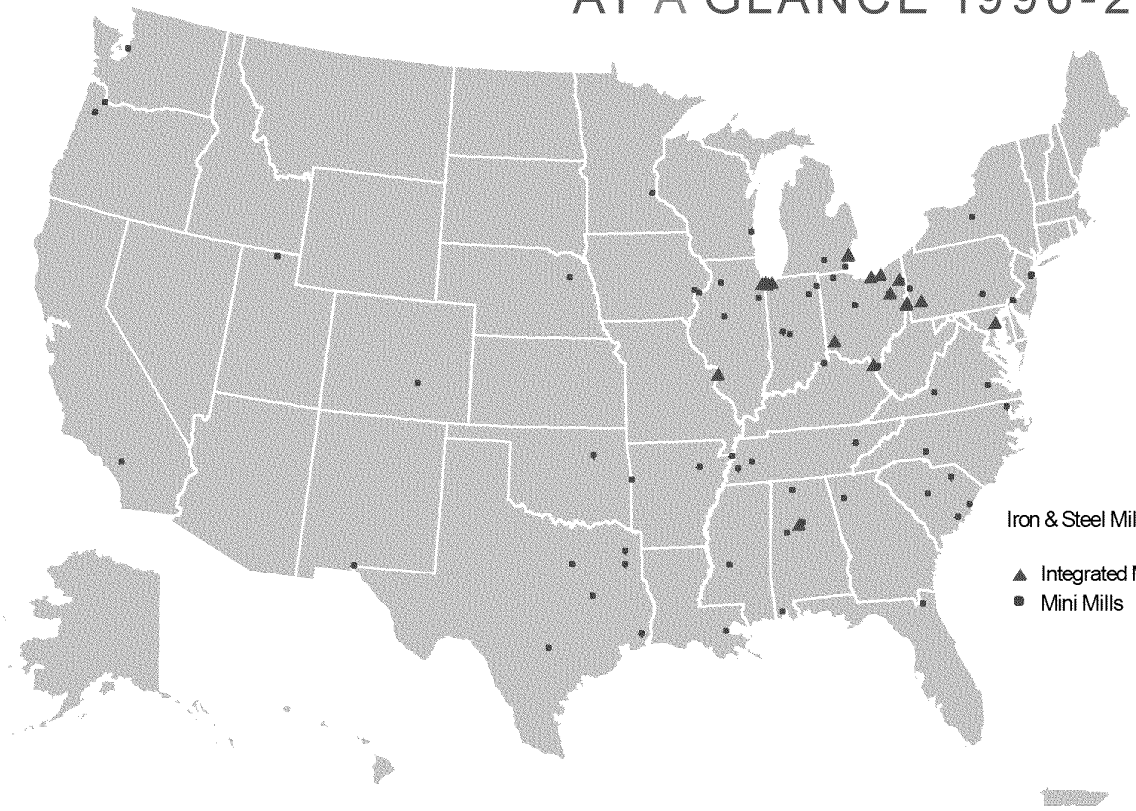
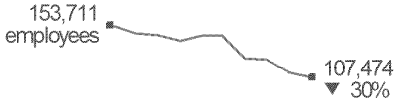
iron & steel

AT A GLANCE 1996-2005[1]





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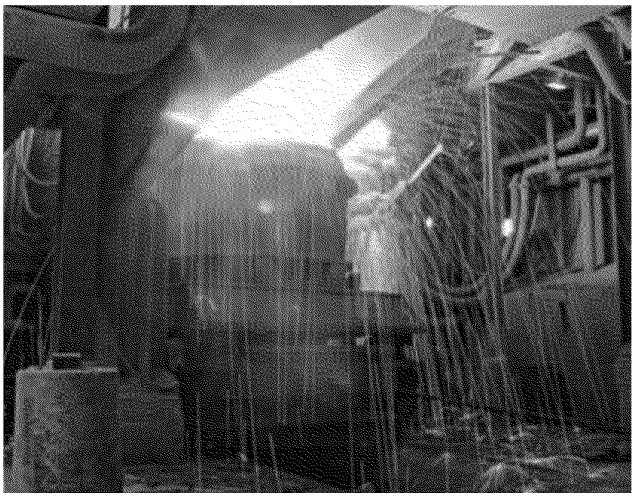


Latest Environmental Statistics[2]

Energy Use: 1.5 quadrillion Btu

Emissions of Criteria Air Pollutants: 755,000 tons

Releases of Chemicals Reported to TRI: 263.9 million lbs.

- airemissions: 3.7 million lbs.
- Water Discharges: 2.9 million lbs.
- Waste Disposals: 257.0 million lbs.
- *Recycling, Energy Recovery, or Treatment: 462 million lbs.*

Hazardous Waste Generated: 1.4 million tons

Hazardous Waste Managed: 1.3 million tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Iron & Steel sector manufactures steel used in products such as vehicles, appliances, machinery, and equipment, and in other sectors. The Construction sector uses more than 22% of steel shipments.[3]

The sector includes facilities that produce carbon steel. As noted in the chapter, some data sets define the sector more broadly, to include facilities producing stainless and specialty steels, facilities producing coke for steel production and other uses, and facilities using steel to make new products. NAICS code 331111, for example, also includes facilities making primary metal products, in addition to steel.[4] Data from the U.S. Geological Survey, used to portray the trend in total number of facilities, also include facilities making stainless and specialty steels.

Integrated mills produce steel from iron ore using a blast furnace, which consumes carbon, primarily in the form of coke, to convert iron ore to molten iron, known as "pig iron." A basic oxygen furnace (BOF) then converts the pig iron, along with up to 30% steel scrap, into refined steel. Steelmakers also rely on coal, natural gas, and other fuels and raw materials, in combination with iron, to produce steel.

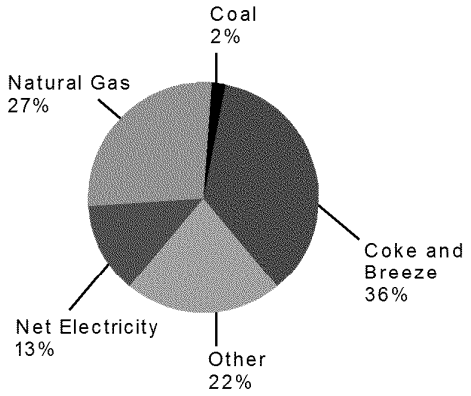
Electric arc furnaces (EAFs) melt steel scrap, along with limited amounts of other iron-bearing materials, to produce new steel. Because scrap can contain a wider range and higher percentage of contaminants, EAF steel requires additional refining to produce some grades of steel that are still made almost exclusively by integrated mills. Steelmakers continue to build new mills using EAFs (also known as mini-mills) and to modernize existing mills, increasing capacity and efficiency while reducing man-hours and energy needed per ton of steel produced.

Energy Use

Significant amounts of energy are required to convert iron ore and scrap to steel. Still, the sector's energy use per

Figure 1
Fuel Use for Energy 2002

Total: 1.5 quadrillion Btu



Note:
1. Other is net steam (the sum of purchases, generation from renewables, and net transfers), and other energy that respondents indicated was used to produce heat and power.
2. Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

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ton of steel shipped improved over the last decade, with corresponding reductions in actual energy used. In 1998, for example, total energy consumption was approximately 1.7 quadrillion Btus,[5] while in 2002 the sector consumed 1.5 quadrillion Btu.[6]

Though both integrated and EAF processes are energy-intensive, integrated steelmaking requires more energy per ton of shipped product.[7] The rising percentage of steel made by EAFs has contributed to the sector's energy efficiency improvements. EAFs consume mostly recycled steel, although integrated mills also rely on steel scrap for a percentage of their raw materials.

Altogether, when recycling steel, rather than making it all from virgin raw materials, the steel industry saves enough energy each year to electrically power 18 million homes.[8] However, further EAF growth may face constraints in the limited supply of scrap or the inability of EAFs to produce many grades of steel that are in high demand.[9]

Integrated steelmaking accounts for roughly 75% of the sector's fuel consumption, relying heavily on coal and coke (which is made from coal), while EAFs account for 64% of the sector's electricity consumption.[10] The sector uses natural gas for about one-quarter of its energy, primarily in heating and annealing furnaces, but also in blast furnaces, boilers, and for EAF injection and cogeneration. Cogeneration, or combined heat and power (CHP), increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source.

Steelmakers can continue to improve energy efficiency with existing options. The U.S. Department of Energy (DOE) estimates that integrated mills could increase use of cogeneration and process improvements—such as using technologies that save energy by improving furnace operations—to achieve savings of up to one million Btu per ton of steel produced, and that EAFs implementing best practices and using commercially available technology could save nearly 2 million Btu per ton.[11] The industry as a whole reported using 12.6 million BTUs (MMBtu) per ton of steel shipped in 2003: 19.55 MMBtu/ton for integrated mills, and 5.25 MMbtu/ton for EAFs.[12]

Research and development, often in partnership with DOE, has led to widespread innovation and process improvements in the sector—such as increasing use of thin slab casting, in which molten steel from steelmaking is cast directly into semi-finished shapes, saving time, labor, energy, and capital by eliminating numerous interim steps.[13] Although opportunities remain, energy efficiency improvements will be incremental without new, transformational technologies and processes for steel production, which the sector is pursuing.[14]

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in the raw materials and fuels used in the steelmaking process, and can be generated in byproducts or end products. CAPs and GHGs are also generated as combustion byproducts from onsite combustion of fuels and the integrated steelmaking process.

Using Coke Oven Gas as a Resource

U.S. Steel and Primary Energy installed a 161-million-watt steam turbine that uses as a fuel 95% of the blast furnace gas generated at Gary Works in Gary, IN. The gas had been flared, but now produces process steam and 40% of the electricity needed for the mill, reducing emissions and fuel use and saving U.S. Steel more than $6 million each year.[15]

Air Emissions Reported to TRI

In 2005, 85 facilities[16] in the sector reported 3.7 million absolute pounds of air emissions to TRI. Between 1996 and 2005, TRI-reported absolute and normalized air emissions declined by 67%, as shown in Figures 2a and 2b, even though production levels for the sector remained relatively steady.[17]

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. The sector's total Toxicity Score declined by nearly half from 1996 to 2005.[18] The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. HAPs accounted for 38% of the sector's absolute air emissions reported to TRI in 2005, and almost all the sector's toxicity-weighted results. The sector's trend for HAP emissions is similar to the trend for all TRI air emissions, as shown in Figure 2a.

The primary sources of HAP emissions are blast furnaces, co-located coke ovens, and EAFs.[19] Manganese, a HAP, accounted for three-quarters of the sector's 2005 Toxicity Score, but also declined by nearly half over the decade. Sector stakeholders have asked EPA to reassess the

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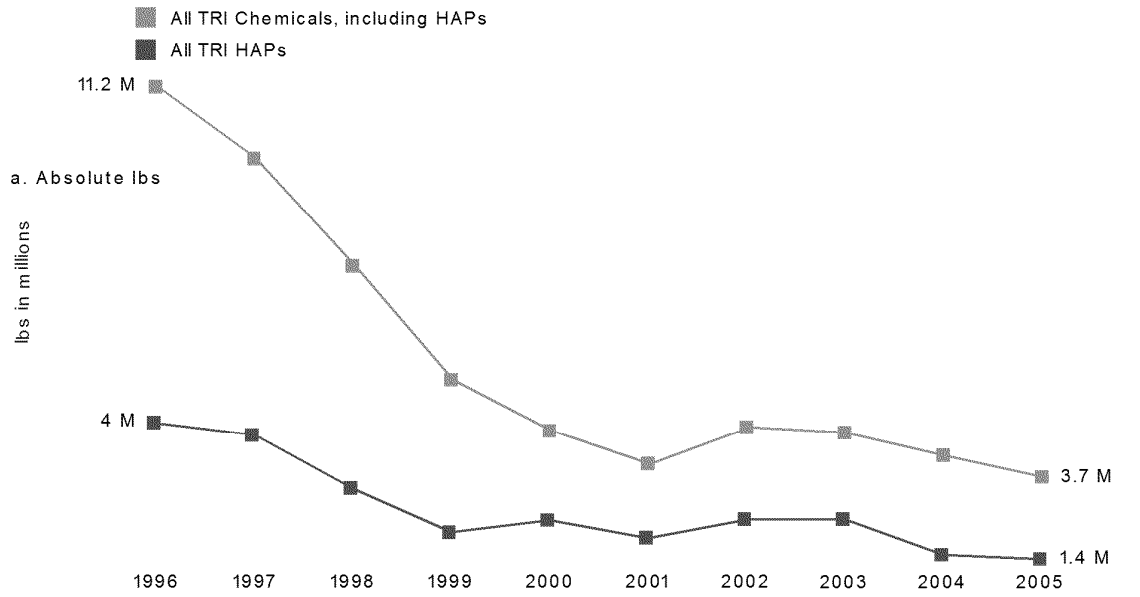
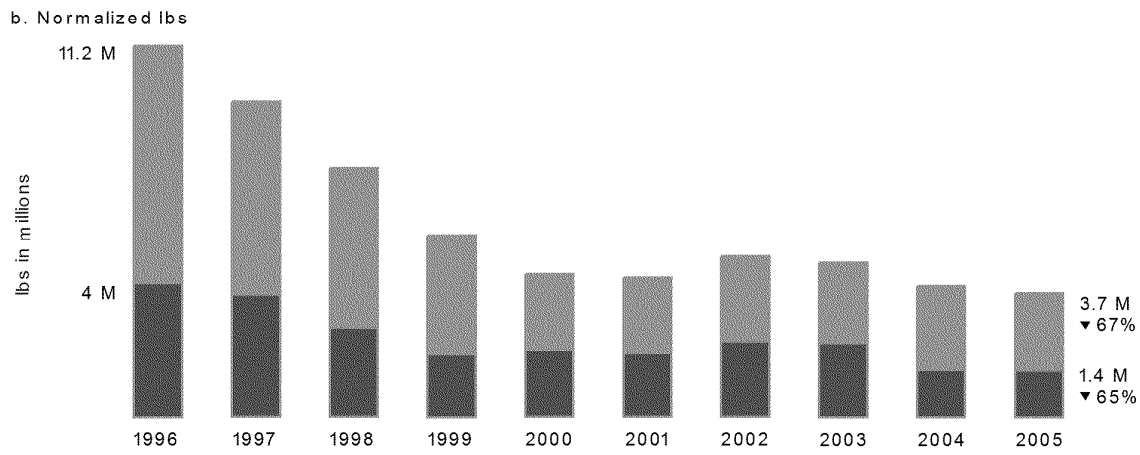
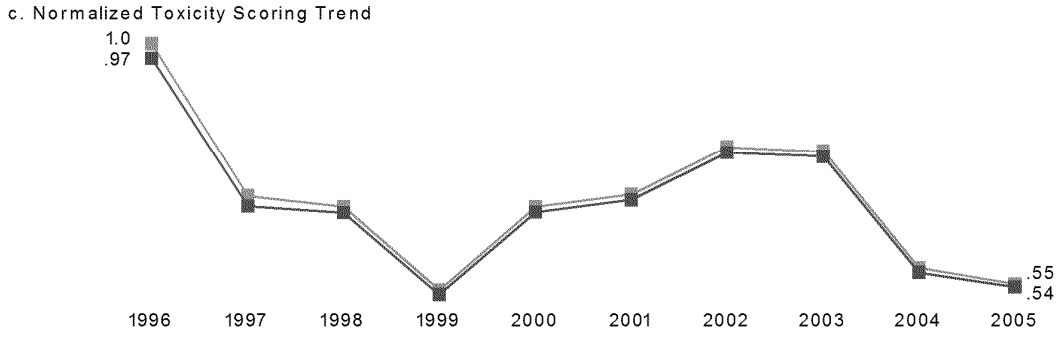
Figure 2

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual production of iron and steel.

Sources: U.S. Environmental Protection Agency, U.S. Geological Survey

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existing, high-toxicity weighting factor for inhalation for manganese. Chromium, nickel, and manganese are alloying elements used in steelmaking, and are therefore also present in steel scrap. Nickel and manganese increase steel's tensile strength; chromium increases hardness and melting temperature. Manganese and other metals are also found in iron ore. They can be emitted when they are added as alloying agents, during "tapping" of molten steel from the furnace, from casting operations, and elsewhere.

Integrated mills and mini-mills each contribute roughly half the sector's TRI-reported absolute air emissions (and the associated relative toxicity).

Table 1 presents the top TRI-reported chemicals emitted to air by the sector based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

Table 1

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Ammonia	355,400[3]	<1%	10
Chromium	20,300	11%[4]	75
Cobalt[5]	1,300	1%	4
Ethylene	199,100	<1%	8
Hydrochloric Acid	352,500	<1%	19
Lead	100,500	6%	83
Manganese	329,100	74%	83
Nickel	23,900	5%	69
Zinc	1,615,500	1%	80
Percentage of Sector Total	**81%**[6]	**98%**[7]	**100%**[8]

Notes:
1. Total sector air releases: 3.7 million lbs.
2. 85 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
5. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
6. Chemicals in this list represent 81% of the sector's air emissions.
7. Chemicals in this list represent 98% of the sector's Toxicity Score.
8. 100% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

1) Absolute Pounds Reported. Zinc, ammonia, manganese, and hydrochloric acid were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005. Zinc emissions result from coating operations and from the recycling of galvanized steel. Ammonia is emitted primarily from coke-making operations, although it and other organics are also found in iron ore. Hydrochloric acid is emitted from "pickling" operations, where it used to remove oxides and scale from the surface of strip steel, steel wire, and some other forms of steel.[20]

2) Percentage of Toxicity Score. Manganese is the top chemical based on Toxicity Scores, as described above. Manganese is essential to iron and steel production by virtue of its sulfur-fixing, deoxidizing, and alloying properties.[21]

3) Number of Facilities Reporting. Lead, manganese, chromium, nickel, and zinc are the most frequently reported chemicals, with almost all the TRI filers in the sector reporting these chemical emissions to air. Lead emissions result from lead in scrap and other raw materials.

Another TRI-reported chemical of interest is mercury. Because methodologies to estimate mercury emissions from individual EAFs have not been formally established, however, the sector's total TRI mercury emissions estimate is conservative. In 2005, 67 iron and steel facilities reported air emissions of mercury totaling 7,200 pounds. Each year, the steel industry uses more than 14 million tons of steel from scrap vehicles, America's most recycled consumer product. Until model year 2003, several automakers installed mercury-containing switches in vehicles, predominantly for convenience lighting in the hood and trunk, and in some anti-lock braking systems. If the switches are not removed from end-of-life vehicles (ELVs), their mercury can be emitted into the environment, especially when steel from shredded vehicles is melted to make new steel. Mercury switches from vehicles are a predominant source of mercury air emissions from EAFs, which EPA estimated may emit 10 tons of mercury per year.[22]

In 2006, steelmakers, EPA, states, automakers, automobile recyclers, scrap recyclers, and environmental groups established the National Vehicle Mercury Switch Recovery Program (NVMSRP) to promote recovery of mercury switches from ELVs. The program partners have implemented the program nationwide.

As part of the NVMSRP, vehicle manufacturers established the nonprofit End of Life Vehicle Solutions Corporation (ELVS), which handles most program logistics. ELVS uses a nationwide environmental services firm to manage the transport and tracking of switches, and the recycling, retorting, or disposal of the recovered mercury. The program, which is still ramping up, has collected more than 1.3 million mercury switches, representing more than 1.4 tons of mercury, from 6,654 participating automobile recyclers who recover and submit the switches.[23]

Criteria Air Pollutants

Table 2 shows CAP and volatile organic compound (VOC) emissions from the Iron & Steel sector for 2002. In 2002, the sector emitted 755,000 tons of CAPs and VOCs. This included nearly 584,000 tons of carbon monoxide (CO), driven by emissions from 10 integrated mills.

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Table 2

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	69,000
NO_X	63,000
PM_{10}	26,000
$PM_{2.5}$	22,000
CO	584,000
VOCs	13,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Greenhouse Gases

The Iron & Steel sector directly emits GHGs mainly from integrated mills from non-combustion processes as well as consumption of fossil fuels. Non-combustion processes produce carbon dioxide (CO_2) and methane (CH_4) through metallurgical coke production, pig iron production, and raw steel production. Non-combustion processes emitted 46.2 million metric tons of CO_2 equivalent ($MMTCO_2E$) in 2005.[24] Between 1996 and 2005, the sector's process emissions of CO_2 and CH_4, combined, fell 33%. These process emissions can be broadly categorized as follows (GHGs emitted by each process are in parentheses):

- Metallurgical Coke Production (CO_2, CH_4): Whether onsite at integrated steel mills or offsite at merchant coke plants, coking coal is heated in a low-oxygen, high-temperature environment within a coke oven.[25] Some carbon contained in the coking coal is emitted during this process as CO_2 and CH_4. Coke-oven gas, a byproduct, can be used for energy purposes.
- Pig Iron Production (CO_2, CH_4): At integrated steel mills, metallurgical coke is used as a reducing agent in the blast furnace to reduce iron ore to pig iron, which is used as a raw material in producing steel. At an integrated steel mill, the coke produced is used in the blast furnace charge for iron production. The carbon contained in the coke also provides heat to the blast furnace, and produces CO_2 through both the heating and reduction process. Iron-bearing blast furnace feed is also produced through sintering, which agglomerates iron-rich small particles, such as iron ore fines and pollution control dusts and sludges, into a porous mass that can be used as blast furnace feed. This process also results in CO_2 and CH_4 emissions.[26]
- Steelmaking (CO_2): At an integrated steel mill, molten iron produced by a blast furnace enters a BOF where the iron and some scrap are combined with high-purity oxygen to produce steel. Carbon contained in both the scrap steel and molten iron is emitted as CO_2. In EAFs, some CO_2 emissions occur from use of carbon electrodes or other carbon-bearing raw materials during the melting of scrap steel.[27]

Release of CO_2 is inherent to the chemical reactions through which iron ore is chemically reduced to make iron, and from the carbon content of iron when reduced to make steel. These emissions cannot be reduced except by changing the process by which iron and steel are made or by capturing and storing the CO_2 after it is created.[28] Research into new methods of steelmaking, discussed above, is also targeting low-carbon processes.

The generation of electricity purchased by steel mills also emits GHGs. The majority of electricity purchased by the sector is for EAFs.

The American Iron and Steel Institute (AISI) participates in DOE's Climate VISION program, and has committed to the goal of achieving by 2012 a 10% reduction in sector-wide average energy consumption per ton of steel produced using a 1998 baseline of 18.1 million Btu.[29] AISI developed emission measurement and reporting protocols, is pursuing identifying and implementing opportunities to reduce GHG emission intensity, and is accelerating investment in research and commercialization of advanced technology.[30] As of 2006, sector-wide average energy efficiency had improved by 15%, compared to the 10% goal.[31] AISI estimates that steelmakers emit 1.24 tons of CO_2 per ton of steel produced, including both direct emissions from processes and fuel use and indirect emissions from generation of purchased electricity.[32] Having produced 108.2 million tons of steel in 2006, the industry's CO_2 emissions for that year would have been 134.2 million tons.[33]

Water Use and Discharges

Steelmakers use water for various processes and purposes, for example, as a coolant for equipment, furnaces, and intermediate steel shapes; a cleansing agent to remove scale from steel products; a source of steam; a medium for lubricating oils and cleaning solutions; and a wet scrubber fluid for air pollution control.[34] Indeed, AISI notes that, "[n]ext to iron and energy, water is the industry's most important commodity."[35]

The largest uses of water are to transfer heat, particularly for cooling (or "quenching") coke after it has been carbonized in coke ovens (8,000–8,500 gallons per ton of coke), in boilers for converting coke oven gas, tars, and light oils (40,000–120,000 gallons per ton of coke), and in boilers for converting blast furnace gas (20,000–60,000 gallons per ton of iron). In production and finishing processes, hot strip mills, which compress reheated steel slabs into hot-rolled sheets and coils through a series of rollers, use the most water (1,000–2,000 gallons per ton of hot rolled strip).[36]

While steelmakers require approximately 75,000 gallons of water to produce one ton of steel,[37] that number includes water that has been recycled, and process and cooling

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water that has been reused. Typically, more than 95% of the water used in steelmaking is recycled. Due mainly to evaporation losses, steelmakers require 13,000–23,000 gallons of additional water per ton of product through all stages of production.[38] Steelmakers obtain water from municipal sources and adjacent water bodies.

Integrated mills use more water per ton of steel than EAFs. With EAFs rising to represent more than half of steel production, intake water withdrawals by the sector have declined by more than 50% since peaking in 1973. Water quality discharge regulations and the cost of effluent treatment have contributed to the sector's increased reliance on recycled water.[39]

Iron and steelmakers discharge wastewater either to Publicly Owned Treatment Works or directly into waterways. Every facility discharging process wastewater directly to waterways must apply for a National Pollutant Discharge Elimination System permit. The permits set numeric limits on specific pollutants based on federal effluent limitations guidelines for each iron and steelmaking process, and include monitoring and reporting requirements. For example, mills involved in certain activities, such as acid pickling and hot coating, are limited in their discharges of metals such as chromium, lead, nickel, and zinc. Cokemaking operations have limits on their ammonia discharges. Sintering operations and blast furnace operations have limits on their discharges of phenols.

In 2005, 72 steel mills reported water discharges of TRI chemicals totaling 2.9 million pounds,[40] a 168% increase from 1996. The sector's reported discharges began to climb in 2000, when one mill began reporting nitrate compounds.[41]

Coke-making quench water becomes contaminated with coke fines and other compounds and contains carcinogenic particulates and VOCs.[42] However, most quench water is reused after removal of the coke fines and other solids. Water discharges are also associated with the treatment of scrubber water used for air pollution control equipment.[43]

Depending on the type of mill, stormwater requirements for iron and steelmakers may include effluent limits on aluminum, zinc, and total suspended solids.

Waste Generation and Management

Wastes in the Iron & Steel sector can be generated from process-related functions or other activities, such as operation of pollution control devices or remediation of contamination. Because of the sector's use of scrap steel, it is a global leader in recycling. The percentage of steel recycled in the U.S. rose to an all-time high of more than 75% in 2005, with 76 million tons consumed.[44] The rate of recycling has continued to rise, along with the production rate of mini-mills. This also raises the quantity of EAF dust from air pollution control equipment that must be disposed or recycled.

Hazardous Waste Management

EAF dust is regulated as a hazardous waste under the Resource Conservation and Recovery Act (RCRA) because of its heavy metal components. This dust, listed as K061, can be recycled to recover zinc and other valuable metals. In the recycling process, the dust is separated into a nonhazardous iron-rich material and a small waste stream with a concentration of the heavy metals. The nonhazardous component can then be used in products, such as bricks. Of the EAF dust generated annually in the United States, however, much is shipped long distances and even exported for recycling.[45] Spent pickle liquor (SPL) from steel finishing operators is another listed hazardous waste (K062), but can also be reclaimed or recycled. In RCRA hazardous waste reporting, individually reported EAF dust and SPL accounted for 55% and 2%, respectively, of the sector's hazardous waste generation in 2005.[46] Additional quantities of these wastes were also reported as part of commingled wastes.

In 2005, 82 iron and steel mills reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 1.4 million tons of hazardous waste, with more than 60% generated by mini-mills. The sector reported managing 1.3 million tons of hazardous waste. Most of the sector's reported hazardous waste was managed through disposal (55%) and reclamation/recovery (36%).[47]

Waste Management Reported to TRI

Wastes generated from this sector largely include EAF dust and SPL. The chemical components of EAF dust include zinc (averaging 20%), lead (averaging 5%), chromium (up to 15%), nickel (up to 4%), and cadmium (up to 3%).[48] These same chemicals accounted for nearly half the air emissions and nearly one-quarter of the total Toxicity Score in 2005. Between 1996 and 2005, normalized air emissions of these chemicals decreased by 44%.[49]

In 2005, the Iron & Steel sector reported managing 726 million absolute pounds of TRI chemicals. When normalized by production, this represented a 34% increase since 1996. Figure 3 shows how the sector managed these chemicals. In 2005, mini-mills accounted for a majority (86%) of the sector's recycling of waste (principally EAF dust) and 63% of the overall waste disposals or releases, while integrated mills accounted for all the sector's energy recovery and more than three-quarters of the overall treatment (principally SPL).[50]

In 2005, the sector reported disposing 257 million absolute pounds of TRI chemicals to land or transferring the chemicals to off-site locations for disposal. As shown in Table 3, zinc accounted for about three-quarters of the total pounds disposed by the sector. Lead, manganese, chromium, and zinc were the chemicals most frequently reported as disposed.

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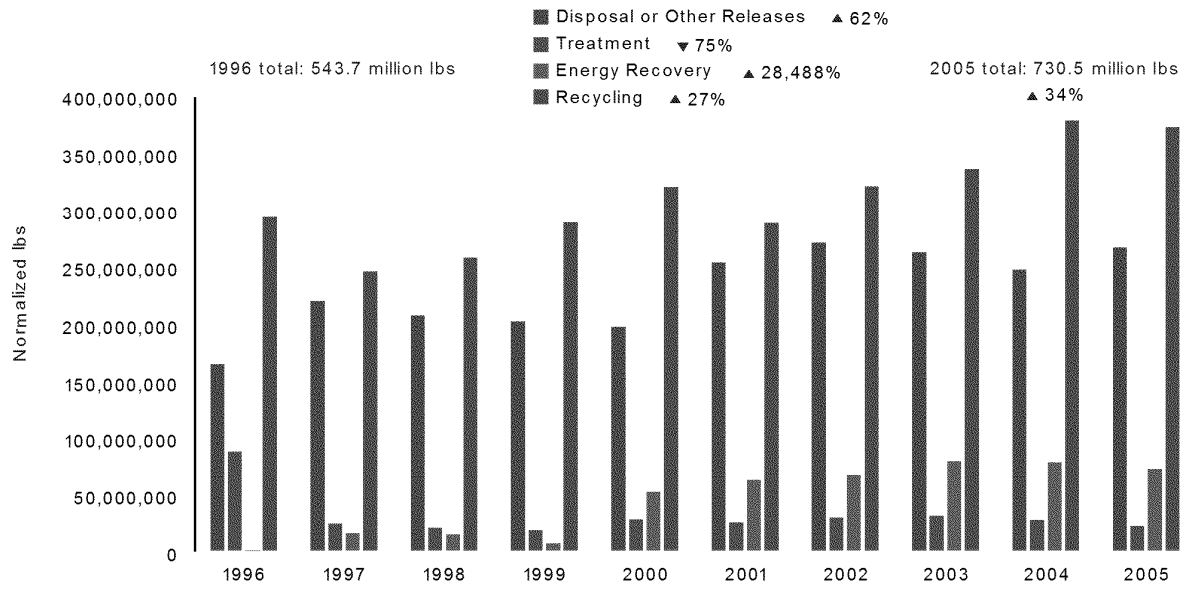
Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual production of iron and steel.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Geological Survey

Table 3

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Chromium	4,327,000[3]	64
Copper	2,328,000	52
Lead	10,139,000	69
Manganese	40,885,000	65
Nickel	489,000	55
Zinc	195,146,000	62
Percentage of Sector Total	**98%**[4]	**84%**[5]

Notes:
1. Total sector disposals: 257 million lbs.
2. 85 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 98% of the sector's disposals.
5. 84% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Additional Environmental Management Activities

An environmental management system (EMS) is a set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency. All integrated steel mills in the United States have adopted formal EMSs based on the ISO 14001 standard (the international standard for EMSs). Approximately one-third of U.S. mini-mills have formal EMSs.[51]

The Steel Manufacturers Association (SMA) has adopted a goal that 25 or more additional EAFs (reaching a total of two-thirds of U.S. mini-mills) will implement EMSs by Earth Day 2009. SMA also has a goal of doubling the number of its members participating in EPA's Performance Track (PT) program in 2008 and 2009, so that at least eight facilities would be in PT by the end of 2009.[52] PT encourages environmental improvement through EMSs, community outreach, and measurable results. Applicants to the program must have an EMS in place.

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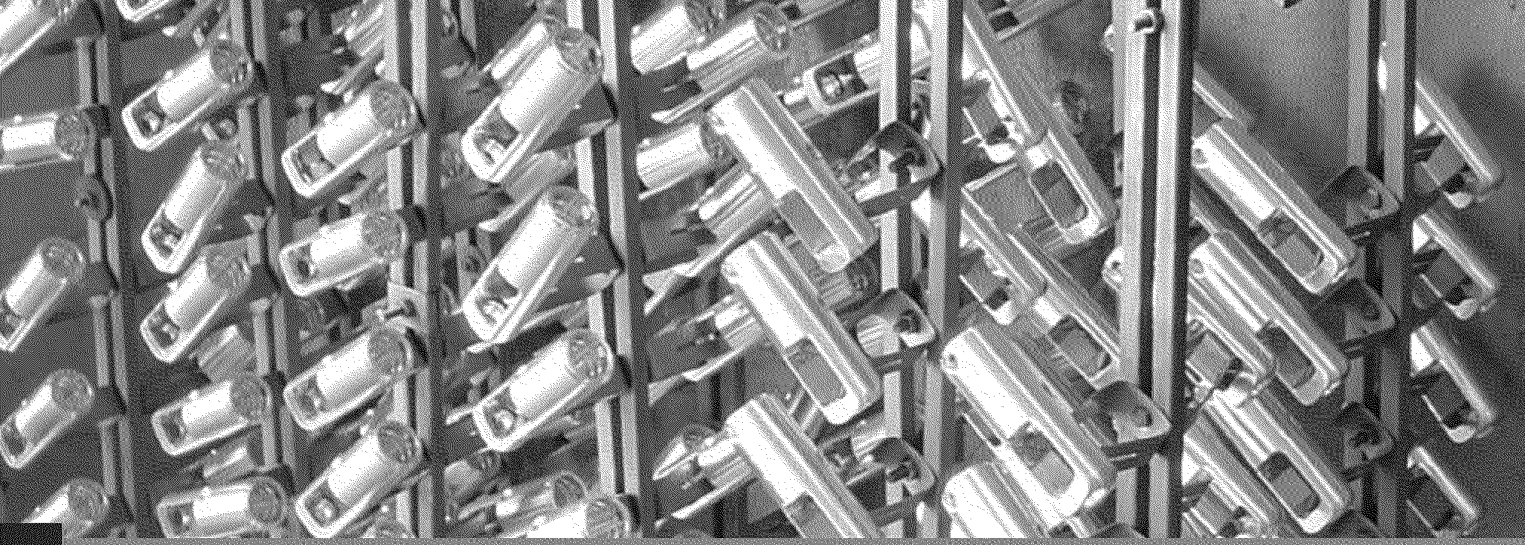
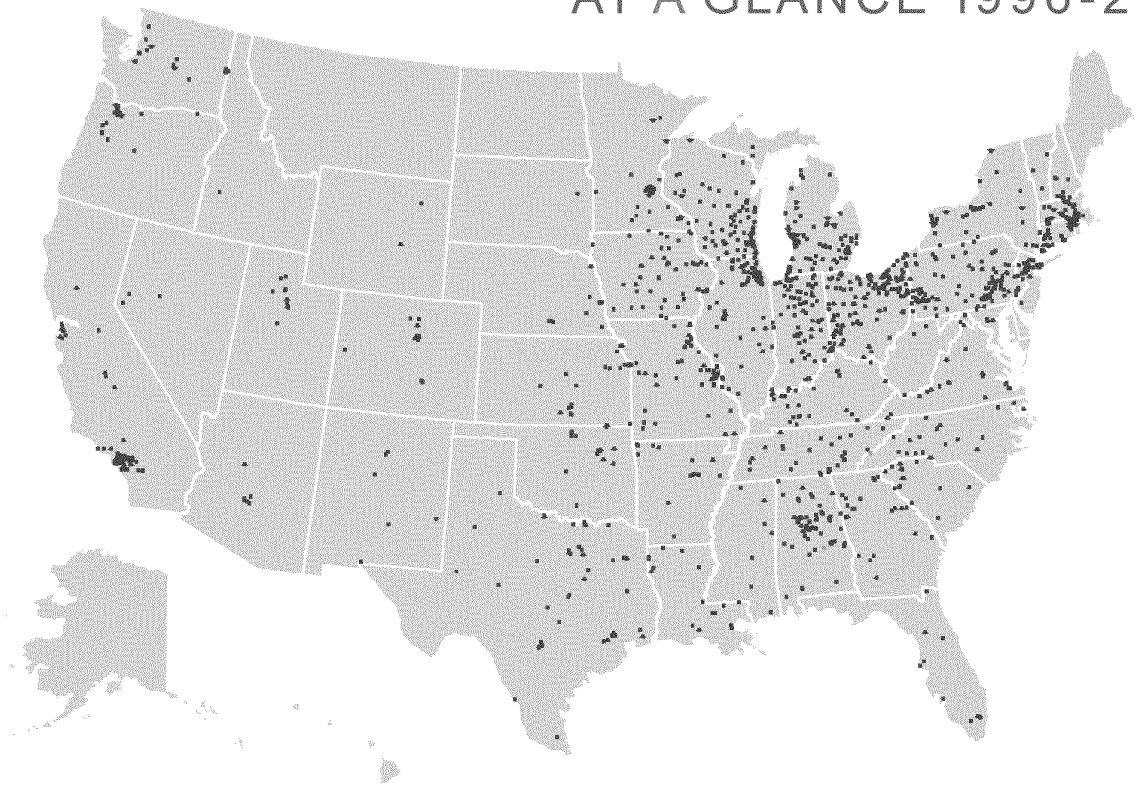


metal Casting

AT A GLANCE 1996-2005[1]



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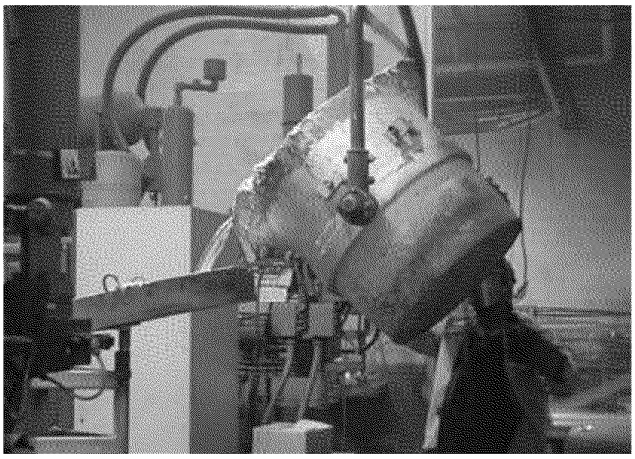


Latest Environmental Statistics[2]

Energy Use: 157 trillion Btu

Emissions of Criteria Air Pollutants: 75,000 tons

Releases of Chemicals Reported to TRI: 49.6 million lbs.

- airemissions: 3.8 million lbs.
- Water Discharges: 68,500 lbs.
- Waste Disposals: 45.7 million lbs.
- *Recycling, Energy Recovery, or Treatment: 127.5 million lbs.*

Hazardous Waste Generated: 30,000 tons

Hazardous Waste Managed: 28,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Metal Casting sector includes establishments that pour molten ferrous metals (iron and steel) or nonferrous metals under high pressure into molds to manufacture castings.[3]

Ferrous metal casting includes those castings made with grey iron, ductile iron, malleable iron, and steel. Each type of iron contains different elements that affect its characteristics. Nonferrous castings are predominantly aluminum but might also be brass, bronze, zinc, magnesium, and titanium.

More than 90% of all manufactured goods in the United States contain cast metal components.[4] These includes engine blocks, transmission housings, and suspension parts for cars and trucks; undercarriages of farm and construction equipment; and pipes and valves for plumbing fixtures and boilers.

U.S. casting operations are now mostly small businesses, with 80% of facilities employing 100 people or fewer.

Energy Use

In 2002, the Metal Casting sector consumed 157 trillion Btu.[5] The major furnaces that casting operations use are cupola (used primarily for ferrous metal casting), electric, reverberatory, and crucible furnaces.

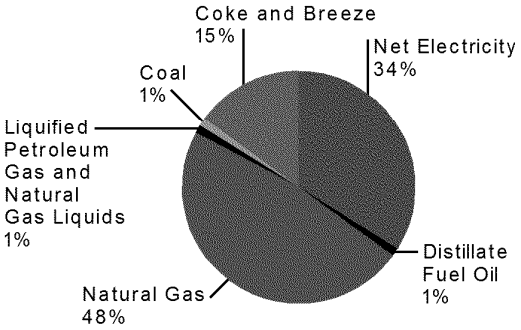
Heating and melting these various metals consumes large amounts of energy, accounting for 72% of the sector's total energy use, according to U.S. Department of Energy (DOE) estimates. Mold and core making account for 7% of the sector's energy use, and finishing accounts for 6%.[6] During molding, foundries use energy for transporting materials, mechanical mixing, and making molds and cores.

As shown in Figure 1, the sector is heavily dependent on natural gas and purchased electricity, making up 48% and 34%, respectively, of the sector's fuel inputs for energy in 2002. Coke, the primary fuel for cupola furnaces, was the third largest energy source, at 15%.[7]

A DOE report on the sector identified several energy-saving opportunities. Casting operations using iron induction can automate furnace temperature and power controls to prevent overshooting temperature settings, and can minimize the time that the lid is open while melting or holding iron. Operations

Figure 1
Fuel Use for Energy 2002

Total: 157 trillion Btu



Note:
Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

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using a cupola furnace can dehumidify blast air to reduce coke consumption and can cover coke storage areas to prevent water from being introduced into the charge.[8]

Air Emissions

Air emissions are a primary environmental concern in the sector, and include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in raw materials and fuels used. CAPs and GHGs also are generated from onsite combustion of fuels. The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act (CAA). Air pollution is a major environmental impact particularly from ferrous metal casting. Because aluminum, used in nonferrous operations, melts at a lower temperature than ferrous metals, nonferrous casting usually results in lower air emissions.

The sector's air emissions result from the various operations in a facility, including metal melting, mold making, handling foundry sand, and die-casting. The majority of metal emissions come from the metal melting operations, while most organic emissions are from handling the binder that holds sand together to produce the cores and molds. Once the binder is combined with the sand, there may be additional organic, particulate, and carbon monoxide (CO) emissions from pouring the molten metal into the casting and from breaking apart the cast. Handling foundry sand results primarily in particulate emissions.

Air Emissions Reported to TRI

In 2005, 662 facilities reported to TRI air emissions of 3.8 million absolute lbs. Between 1996 and 2005, TRI-reported air emissions, in absolute pounds, declined 63%, as shown in Figure 2a. Because production levels for the sector remained relatively steady over the 10 years, the emissions trend, when normalized by ferrous and nonferrous shipments, was very similar to the trend for absolute emissions, as shown in Figure 2b. Some 75% of the sector's air emissions in 2005 were reported by ferrous metal casting facilities, while nonferrous facilities reported the remaining 25%. In the same year, ferrous metal casting facilities contributed to 62% of the sector's total shipments, while nonferrous contributed to 38%.

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. The sector's Toxicity Score declined 82% from 1996 to 2005.[9] Three chemicals—manganese, chromium, and diisocyanates—accounted for 81% of the sector's total Toxicity Score. Manganese and chromium emissions result from melting; furnaces melting metal emit dust, metallic particles, and metal oxide fumes, along with the products of combusted fuel. Diisocyanates, associated with binding materials, are emitted as a result of exposure to air. The apparent spike in 1996 was exacerbated by diisocyanates emissions reported by one facility, which, in subsequent years, reported no diisocyanates emissions. The sector's reported emissions of all three chemicals have declined since 1996.

During this same period, regulations led to increased use of pollution control equipment, and to equipment upgrades. Technology related to the binding process has also improved; changes in binder ingredients and processing, for example, have promoted reductions in volatile organic compound (VOC) emissions.

In 2005, 514 facilities reported 2.5 million lbs. of HAP emissions. These HAPs accounted for 66% of the sector's air emissions in 2005 and 83% of the sector's overall Toxicity Score. Over the 10-year period presented, absolute and normalized pounds of HAPs emitted declined by 65%.[10]

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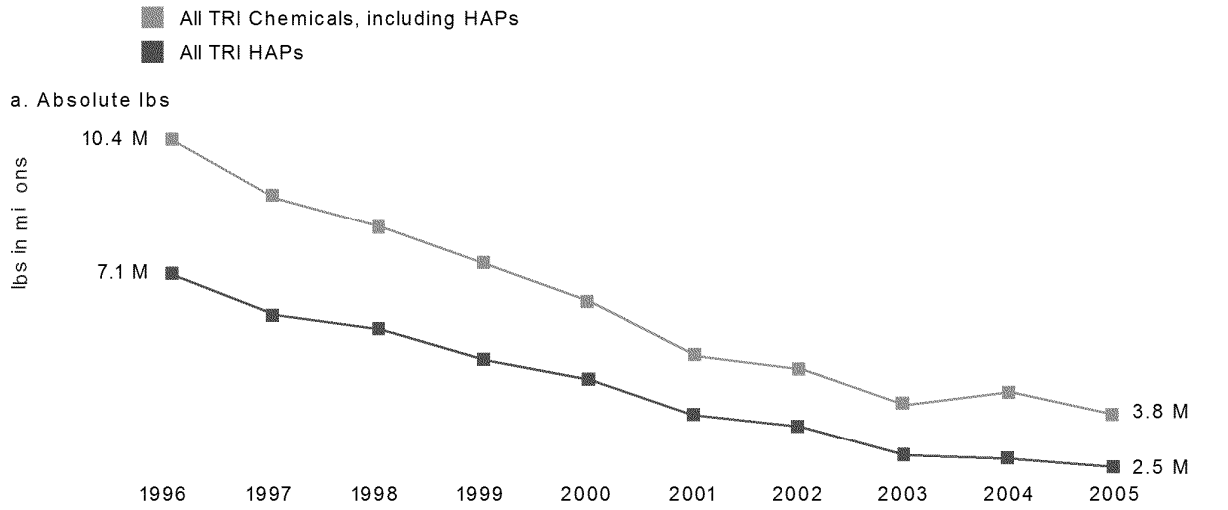
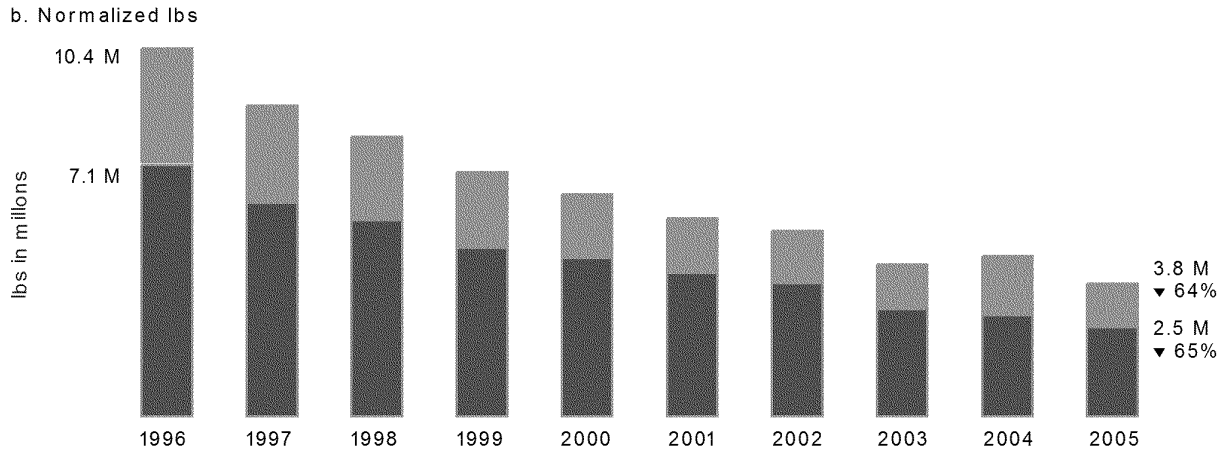
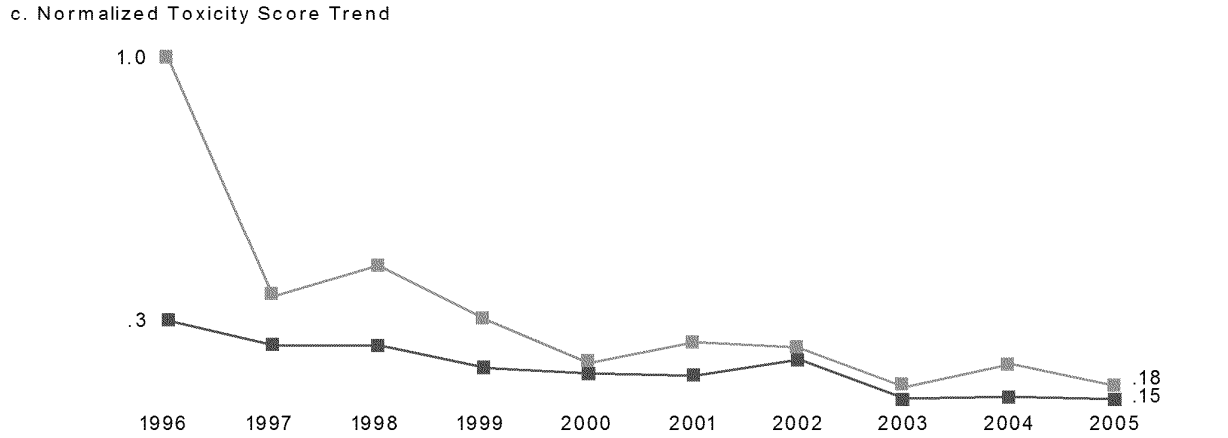
Figure 2

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by ferrous and nonferrous shipments.

Sources: U.S. Environmental Protection Agency, American Foundry Society

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Table 1 presents the top TRI-reported chemicals emitted to air by the sector based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Xylene and aluminum were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005.
2) Percentage of Toxicity Score. The top chemical based on Toxicity Scores was manganese, which has a high toxicity weight and was emitted in large quantities. Chromium and diisocyanates were emitted in smaller quantities but are among the chemicals with the highest toxicity weights.
3) Number of Facilities Reporting. Lead was the most frequently reported chemical, with more than half the facilities in the sector filing TRI reports for air emissions of lead.

Table 1
Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
Aluminum	356,000[3]	1%	49
Benzene[4]	243,000	<1%	9
Chromium	53,000	26%[5]	168
Copper	153,000	1%	322
Diisocyanates	16,000	16%[6]	41
Lead	96,000	5%	372
Manganese	193,000	39%	206
Nickel	47,000	9%	211
Phenol	328,000	<1%	60
Xylene	438,000	<1%	10
Zinc	268,000	<1%	91
Percentage of Sector Total	**58%**[7]	**96%**[8]	**86%**[9]

Notes:
1. Total sector air releases: 3.8 m llion lbs.
2. 662 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
5. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
6. Calculation of Toxicity Score for diisocyanates conservatively assumed that all diisocyanates emissions were hexamethylene diisocyanates. Other diisocyanates chemicals with lower toxicity scores may constitute the majority of reported diisocyanates emissions from the sector. Thus, RSEI analyses may overestimate the relative harmfulness of diisocyanates emissions.
7. Chemicals in this list represent 58% of the sector's air emissions.
8. Chemicals in this list represent 96% of the sector's Toxicity Score.
9. 86% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Criteria Air Pollutants

Table 2 shows CAP and VOC emissions from the Metal Casting sector for 2002.

Table 2
Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	3,000
NO_X	5,000
PM_{10}	18,000
$PM_{2.5}$	13,000
CO	32,000
VOCs	17,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Conversion to Low-Emission Technology Binders and Process

Gregg Industries, in El Monte, CA, received neighborhood odor complaints when using a no-bake casting line using phenolic urethane resin for prototype castings and customer casting qualification. The company replaced the phenolic resin with an inorganic, highly modified sodium silicate resin. The resin dramatically reduced smoke and odor from the no-bake operation. The foundry also replaced an odor-causing organic core resin with a similar modified silicate core resin. After the change to the low-emission technology resins, the foundry saw lower binder costs, fewer labor hours to produce the cores, and lower cleaning room costs. Also, the new low-emission core technology contributes to the continuing decline in casting scrap.[11]

Water Use and Discharges

Metal Casting facilities use water in their production processes and discharge wastewater to either Publicly Owned Treatment Works or directly into waterways. Wastewater from the sector mainly consists of noncontact cooling water and wet scrubber wastewater. Foundries using cupola furnaces also may generate wastewater containing metals from cooling slag with water. Certain finishing operations, such as quenching and deburring, may generate wastewater containing oil and suspended solids.

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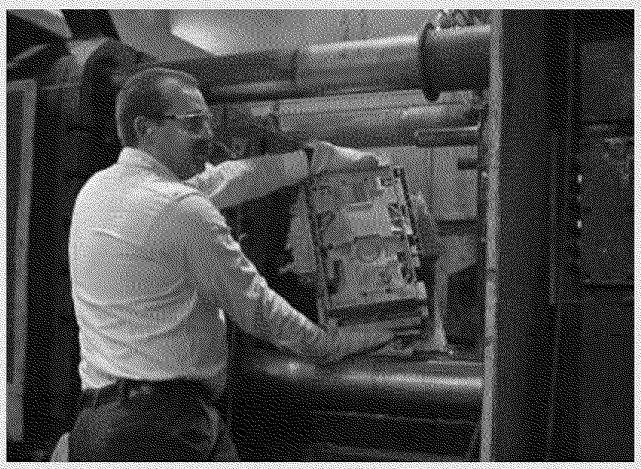


Every facility discharging process wastewater directly to waterways must apply for a National Pollutant Discharge Elimination System permit. The permits typically set numeric limits on specific pollutants and include monitoring and reporting requirements. For metal casters, regulated pollutants and the associated limits vary depending on the type of casting operation (aluminum, copper, zinc, or ferrous casting), but most facilities are regulated in their discharges of copper, lead, zinc, and total suspended solids (TSS).[12]

In 2005, 236 facilities reported water discharges of TRI chemicals totaling 68,500 lbs.[13] This represented a decline of 52% since 1996.[14]

Facilities with materials exposed to precipitation also are regulated for stormwater runoff, usually under a general permit providing sector-specific limits. Depending on the type of foundry, stormwater requirements for metal casting facilities may include effluent limits on copper, zinc, iron, aluminum, and TSS.

Waste Generation and Management

Waste management is another key environmental issue for Metal Casting facilities. Metal casting wastes fall into four main categories: sand, slag, dust, and other. The sand used to create molds and cores accounts for a large portion of the waste generated at foundries.[15] The high-quality sand required for casting is expensive, so foundries reuse sand to the extent possible. Sand that no longer can be used by iron or steel foundries is often landfilled or beneficially reused.

Slag, which can make up about 25% of a foundry's solid waste stream, is a glassy mass with a complex chemical structure. Slag is composed of metal oxides from the melting process, melted refractories, sand, coke ash (if coke is used), and other materials. Large quantities of slag are generated from iron foundries using cupola furnaces.

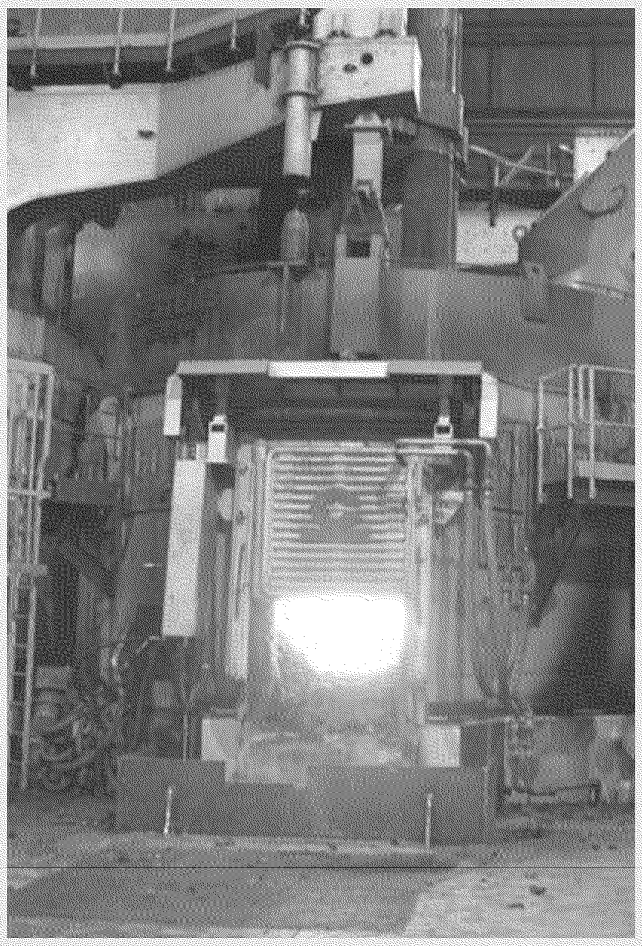
During casting, some metal is converted to dust or fumes and collected by pollution control equipment such as baghouses, electrostatic precipitators, or wet scrubbers.

Some processes for making cores require strongly acidic or basic substances for scrubbing the off gases and can generate sludges or liquors. These sludges or liquors are typically pH-controlled prior to discharge to the sewer system.

Hazardous Waste Management

Both ferrous and nonferrous facilities generate hazardous waste, including hazardous waste from finishing operations. Ferrous facilities generate hazardous wastes mostly from pollution control equipment, especially from melting furnaces. Nonferrous facilities tend to produce hazardous wastes as foundry sand contaminated with heavy metals. About 2% of all spent foundry sand is hazardous. Casting sands used in the production of brass or bronze castings may also exhibit toxicity characteristics for lead or cadmium, making them a hazardous waste.

In 2005, 170 facilities reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 30,000 tons of hazardous waste. Wastes captured by air pollution control equipment were the largest source of hazardous waste. Facilities reported managing 28,000 tons of hazardous waste in 2005, most of which was managed through destruction or treatment.[16]



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Waste Management Reported to TRI

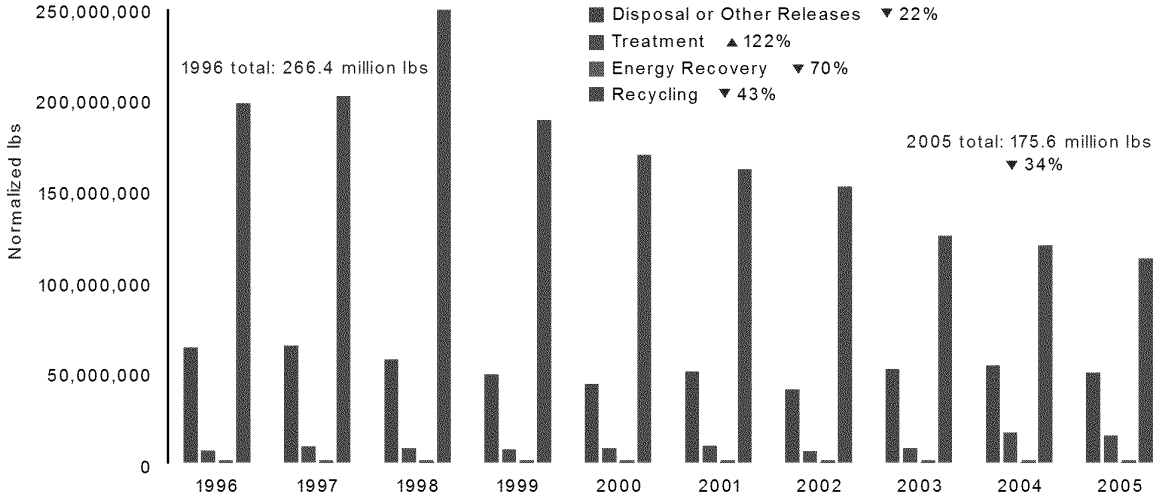
In 2005, the sector reported managing 177 million absolute lbs. of TRI chemicals as waste. Of the TRI waste managed (which included disposal and recycling), 56% was reported by nonferrous facilities; ferrous metal casting accounted for 44%. Both nonferrous and ferrous facilities recycle extensively, though nonferrous facilities recycle a higher percentage. About two-thirds of the materials the sector reported to TRI as waste in 2005 were recycled.[17] The high recycling rate derives partly from the nature of the industry; if a problem occurs in the casting, the defective product can be melted down and cast again, on or offsite.

The quantity of waste managed in 2005 was 34% less than in 1996, with little change in the sector's quantity of product shipped. In 2005, 28% of TRI-reported waste was disposed or released, while 8% was treated and 64% was recycled. Foundry sand was recycled onsite and offsite.[18]

In 2005, 45.7 million lbs. of TRI chemicals were disposed to land or transferred to offsite locations for disposal.

Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by ferrous and nonferrous shipments.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, American Foundry Society

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Manganese accounted for about one-third of the total pounds disposed. As shown in Table 3, lead and copper were the chemicals most frequently reported as disposed. The sector's disposals and other releases were driven by ferrous metal casting facilities, which accounted for 75% of disposals and releases.

Table 3
Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Aluminum	7,709,000[3]	31
Chromium	7,112,000	149
Copper	1,775,000	210
Lead	1,983,000	270
Manganese	14,938,000	187
Nickel	556,000	162
Zinc	9,636,000	63
Percentage of Sector Total	96%[4]	60%[5]

Notes:
1. Total sector disposals: 45.7 million lbs.
2. 662 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 96% of the sector's disposals.
5. 60% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Promoting the beneficial reuse of foundry sand is a priority for EPA and for the American Foundry Society (AFS). Recent efforts to increase beneficial reuse rates appear to be paying off, as more sand is reused now than ever before. With input from the National Center for Manufacturing Sciences and EPA, AFS developed a survey to help quantify the amount of sand available for reuse, characterize current reuse practices, and identify barriers to reuse. Based on the 244 responses and a broader telephone survey, AFS determined that the industry beneficially reuses 2.6 million tons of sand per year, representing 28% of the total tons of sand available for reuse. The most common barrier to reuse that respondents noted was lack of a local market for used foundry sand.[20]

Spent Foundry Sand Used in Rain Gardens

In June 2007, the city of Seven Hills, OH, partnered with a commercial landscaping supply company, Kurtz Bros., Inc., to install a rain garden on community property near City Hall. A rain garden is a landscape that filters stormwater to remove impurities before the water enters storm drains or surface water. Spent foundry sand was key to the rain garden soil mix. By purchasing bioretention soil made with spent foundry sand, the city paid about half as much as it would to purchase soil made with unused sand. Foundries paid less for Kurtz to remove the spent sand than they would to landfill the sand.[19]

Other Environmental Management Activity

The North American Die Casting Association (NADCA) promotes environmental management systems for die casting operations, and recently published a book titled Environmental Management for Die Casting. The book has been given away to NADCA corporate members and has been sold to more than 75 other die casting operations around the United States.

NADCA has further developed a series of questions for owners so they will understand where their operations stand in terms of environmental compliance for air, water, and solid waste. More than 30 companies have used this system to evaluate themselves.[21]

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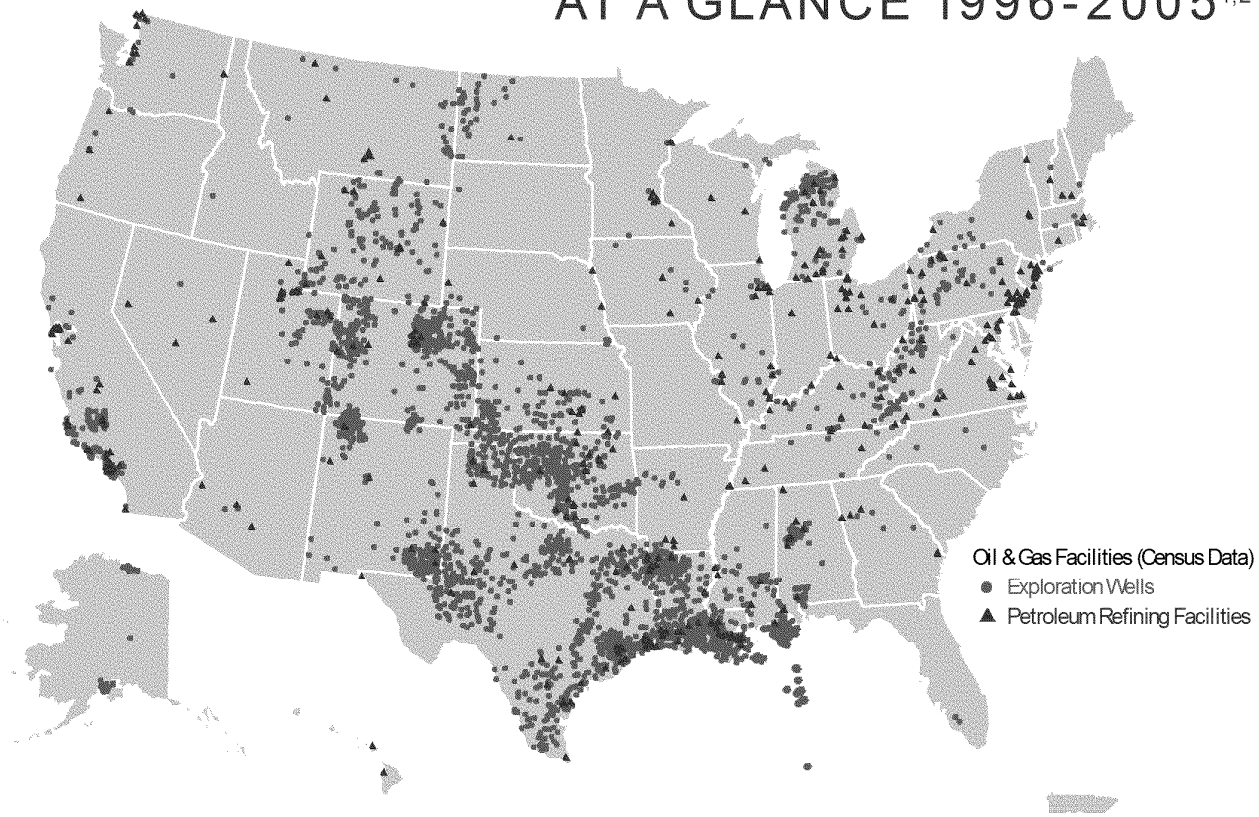
oil & gas

AT A GLANCE 1996-2005[1,2]



exploration and Production

876,230 wells → 896,629 ▲ 2%

247,800 employees → 270,200 ▲ 9%

38,600,000 billion Btu produced → 35,700,000 billion Btu ▼ 8%

refining

164 refineries → 148 ▼ 10%

92,000 employees → 68,000 ▼ 26%

5.2 billion barrels crude oil input into refineries → 5.5 billion ▲ 6%

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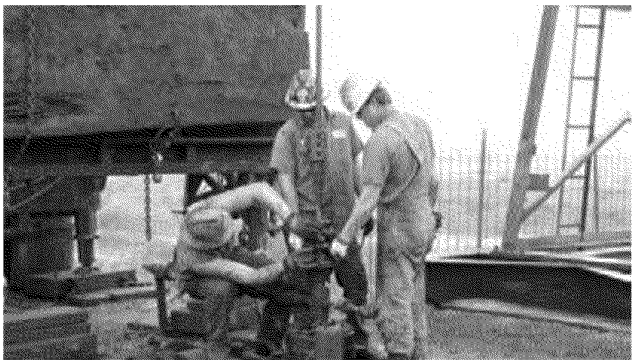

Profile

The Oil & Gas sector includes the following operations, which are subject to a number of federal and state regulations:

- Exploration and Drilling: Onshore and offshore geophysical operations, including seismic studies, engineering, well testing, drilling operations, and transportation of personnel or equipment to and from sites.
- Oil and Gas Production: Operation, maintenance, and servicing of production properties on- and offshore, including transportation to and from sites.
- Petroleum Refining: Distillation, hydrotreating, alkylation, reforming, and other distinct processes for converting crude oil into petroleum products.[3]

In 2005 the Oil & Gas sector included 498,454 oil wells and 398,161 gas wells in operation. The sector employed 1,381 rotary rigs for drilling new wells.[4] The United States is the world's third-largest petroleum producer and second-largest natural gas producer.[5]

Petroleum products derived from crude oil through the refining process include gasoline (motor fuel), distillate (diesel fuel, home heating oil), kerosene (jet fuel), petroleum coke, residual fuel oil (industrial and marine use), petroleum gases (liquified petroleum gas, ethane, butane), elemental sulfur, asphalt and road oils, petrochemical plant feedstocks, and lubricating oils.

The environmental impacts of the sector's activities vary significantly. This chapter is divided into two sections, discussing the environmental implications of exploration and production (E&P), followed by a discussion of petroleum refining.

exploration and Production[6]

E&P operations locate and extract crude oil and natural gas from geologic formations. Geologic and regional differences, as well as basin-specific approaches to extract the resources available, influence the environmental footprint associated with E&P operations. This section overviews the major processes and factors affecting that footprint.

Exploration and Drilling

Exploration for oil and gas involves geologic testing of prospective formations. These activities often involve construction of new roads in remote areas and air emissions caused by vehicular traffic to, from, and within potential drilling locations. Drilling is done with truck-mounted rigs powered by diesel engines, which also affect air quality. Operators prepare a pad for drilling equipment including creation of pits and ponds to contain various fluids and mud used in drilling and to manage the drill cuttings (rock displaced while drilling the well). Operators also install tanks or pipes to gather the resources produced.

Oil Production

The classifications of light, medium, heavy, or extra-heavy refer to the crude oil's gravity as measured on the American Petroleum Institute (API) scale, and reflect the energy required and environmental impacts inherent in producing and refining the oil. Light crude oil, for example, flows naturally or can be pumped relatively easily to the wellhead. Conversely, heavy crude oil does not flow easily and has higher viscosity than light or medium crudes, requiring enhanced oil recovery (EOR) processes such as heating or diluting.

When crude oil, associated natural gas, and formation water arrive at the wellhead, operators must separate them before further processing and transport. The water is generally high in saline content and may contain hydrocarbons. Separator units near the wellhead separate the oil from the associated natural gas. The natural gas is processed to recover natural gas liquids (mostly propane and butane). Impurities such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) also are removed from the gas before it is transported. If pipeline access is not available, the gas may be used on location to power production equipment or may be re-injected into the oil reservoir to maintain reservoir pressure.

Water produced with oil must be removed because it is corrosive and an impediment to transportation and storage. Water is separated at gathering stations and oil storage tanks in the field.

Measurable quantities of oil remain in the reservoir once primary production processes have concluded, and additional resources can be recovered through EOR processes. Such processes supplement natural reservoir forces to improve flow rate and recovery. Representative EOR techniques include water flooding, gas injection, and chemical and thermal processes—all of which can have environmental impacts.

Natural Gas Production

Production of gas generally begins as natural flow from the wellhead into the gathering system. As a field matures, reservoir pressure begins to decline and gas compression

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equipment helps recover the gas. In cases where "pipeline-quality" natural gas is produced at the wellhead, producers move the product directly to the pipeline grid. In most cases, raw gas streams must be treated prior to introduction into the pipeline system.

Water and heavier hydrocarbons are removed at the wellhead, and may result in water discharges and waste disposal issues. Light hydrocarbons are removed at a natural gas processing plant and sold for other uses. In addition, some natural gas production yields "dry gas" with no associated crude oil, condensate, or liquid hydrocarbons. Gas also may contain non-hydrocarbons such as CO_2, H_2S, and nitrogen. If present in sufficient concentrations, these constituents also are removed at natural gas processing plants.

As natural gas supplies from the nation's historic production regions are depleted, the industry's focus has shifted. For example, the Rocky Mountain region contains prospective production areas that are expected to make major contributions to U.S. natural gas reserves. In addition, shale gas production is becoming a key component of U.S. supplies; the Barnett Shale in northern Texas is one of the largest onshore natural gas fields in the country.

Unconventional Oil and Gas Resources and Emerging Technologies

Unconventional oil and gas resources are defined loosely as resources that are deeper or more difficult to recover than those that have been recovered historically. Given the mature state of the domestic petroleum industry and current access limitations (e.g., prohibitions or restrictions on developing offshore and onshore sites within sensitive ecosystems), oil and gas resources from conventional formations within the United States have been largely depleted. Unconventional resources require advanced recovery techniques and may require that extracted material be upgraded to meet relevant fuel specifications. For example, oil shale must be heated to release petroleum-like liquids that can be turned into fuel. Unconventional gas resources usually require more wells (closer well spacing) to recover the gas resource than in recovery of gas from conventional gas resources. Common practice for unconventional gas production can require 8 to 16 times as many wells per area of land as for historical conventional gas recovery. The impact of this greater well density is mitigated by the use of advanced drilling techniques, which allow multiple wells to be drilled from one well pad. To be viable, unconventional resource recovery methods must also address a wide range of socioeconomic and environmental issues. The following are representative of unconventional resources and emerging technologies.

Tight Gas and Coal Bed Methane (CBM)

Tight gas refers to natural gas found in less permeable and porous formations, such as limestone or sandstone. For recovery, the gas-bearing formation must be broken up, or "fractured," to allow gas to flow to the well. This requires many more wells than conventional recovery. CBM refers to natural gas trapped in underground coal seams, which can be extracted before mining the coal. CBM production often requires removing large amounts of water from underground coal seams before the methane (CH_4) in the seams can be released and recovered as an energy source.

Directional and Horizontal Drilling

New methods to reduce the cost and environmental impacts of recovering unconventional resources include directional and horizontal drilling techniques. Directional drilling includes all forms of drilling where the hole is slanted or curved from the drilling site to reach the target reservoir. Directional drilling commonly is used offshore as evolving techniques enable producers to reach oil reserves in extremely sensitive ecosystems while most of the drilling equipment is miles away. In onshore operations, directional drilling greatly reduces the amount of surface disturbance by enabling producers to use a small surface well pad and to drill outward to access larger portions of the target reservoir.

Horizontal drilling enables the wellbore to be shifted from a vertical to a horizontal orientation. By using horizontal drilling techniques, operators can drill many wellbores from a single location, thus reducing the above-ground footprint. Horizontal drilling is used extensively in accessing unconventional natural gas resources; however, due to the lower porosity of the underlying formations, more wells must be drilled (e.g., tighter well spacing) to extract the gas.

Advanced drilling rigs may also be designed to slide on rails to the next destination within a production area, reducing environmental disturbances and improving efficiency.

Energy Use

E&P operations need energy to power oil and gas recovery. Requirements range from prospecting for new wells, to moving trucks and equipment onsite and off, to drilling and pumping the wells. Development drilling can involve numerous wells, and the power used to operate and transport drilling rigs increases the energy intensity of E&P operations. To increase pressure and enhance recovery rates from largely depleted reservoirs, most onshore oil production operations use pumps powered by electricity or natural gas.

The energy required for E&P increases as the resource recovered becomes more difficult to access and produce. For example, approximately two-thirds of U.S. gas wells are now drilled into unconventional formations. While sometimes shallower than conventional wells, unconventional gas wells typically require more energy than conventional wells for well stimulation operations. In the case of CBM and some shale gas operations, energy use for producing, managing, and treating large volumes of produced water is significant.[7]

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Air Emissions

Air emissions from E&P operations include criteria air pollutants (CAPs), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). E&P air emissions are generated by combustion in stationary and mobile internal combustion engines, gas processing equipment, and other activities. In addition, E&P operations produce air emissions through venting and flaring. Fugitive emissions of methane are also significant.

Oil and natural gas production is included as an area source category for regulation under EPA's Urban Air Toxics Strategy, is subject to New Source Performance Standards for new or modified stationary sources, and is subject to state and federal operating permit requirements to limit air pollution. E&P operations are not included within the scope of industries that report to EPA's Toxics Release Inventory (TRI), and too few facilities are currently included in the National Emissions Inventory (NEI) to be representative of the sector.

Criteria Air Pollutants

EPA has, however, analyzed the sector's air emissions in Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming) using state emissions inventory data developed by the Western Regional Air Partnership (WRAP).[8] A draft study prepared by EPA's Sector Strategies Program characterized regional air emissions and non-air pollution from produced water and drilling wastes. Region 8, which includes the Rocky Mountains (Rockies), has experienced tremendous growth in natural gas production activities in the last decade and the trend is likely to increase. Table 1 shows 2002 CAP emissions from oil and gas exploration and production reported by WRAP in Region 8.

Table 1

CAP and VOC Emissions in Region 8 2002

Pollutant	Estimated Emissions in Tons
VOCs	262,953
NO_X	87,130
CO	37,880
SO_2	18,385
PM	834

Source: U.S. Environmental Protection Agency

Greenhouse Gases

Major GHG emissions from E&P operations include CO_2 and CH_4. Acid-gas removal units that remove CO_2 from natural gas are the primary source of GHGs from natural gas processing plants. Indirect sources of CH_4 are venting and fugitive emissions. A substantial portion of field production CH_4 emissions come from pneumatic devices such as liquid level controllers, pressure regulators, and valve controllers. Other sources of CH_4 emissions are dehydrators and gas engines.

Table 2 shows estimated GHG emissions from Region 8 for 2002. When CH_4 emissions are weighted by their global warming potential (21 times that of CO_2), CO_2-equivalent methane emissions represent the sector's largest non-CAP emissions, at more than 10 million tons. Although those emissions are not regulated, anticipated GHG regulations affect current and planned E&P activities.

Table 2

GHG Emissions in Region 8 2002

Pollutant	Estimated Emissions in Tons
CH_4	10,366,442 ($C0_2$-equivalent)
CO_2	5,191,897

Note:
Estimated emissions of CH_4 were 493,640 tons.

Source: U.S. Environmental Protection Agency

Water Use and Discharges

E&P operations entail various water uses and discharges, with related environmental implications. EPA data systems contain limited information on discharges to waterways, as most operations are regulated under general permits and report to state, rather than federal, agencies.[9]

Producers use water to assist in resource extraction, from enhanced oil recovery to hydraulic fracturing. Oil and gas operations must also manage "produced water"—water that either occurs naturally in the formation and must be disposed of or reused after extraction, or water that is injected to stimulate production.

Reducing Emissions and Saving Money

In 2005 the Devon Energy Corporation, WY, prevented the release of nearly 6.0 billion cubic feet (Bcf) of CH_4, equivalent in terms of GHG emissions to 2.6 million tons of CO_2. By implementing emissions reduction techniques in concert with various process improvements, Devon retained significant volumes of product (e.g., methane gas in the pipeline) and realized an economic benefit of more than $43 million. Devon received EPA's 2005 Natural Gas STAR Production Partner of the Year award.[10]

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The most widely used EOR technique involves injecting water into the reservoir (e.g., "water flooding"). Water, injected under pressure, pushes the oil toward the recovery or producing well. The recovered fluids (water and oil) are separated; oil is sent on to distribution, and water is either treated and reused or disposed in permitted underground injection control wells. Injection wells are permitted through state oil and gas regulatory agencies that place limits on injection volume and pressure. Water flooding represents a major source of produced water managed by producers.

Hydraulic fracturing is the most commonly used method of gas well stimulation. It involves pumping a water-based solution into the formation at pressures up to 10,000 pounds per square inch, which induces fractures in the formation. A material such as silica sand also is pumped in to prop the fractures open, enabling the gas to flow more freely to the wellbore. Fracturing generally is accomplished with large truck-mounted pumps powered by diesel engines. Today, tight sand fracturing in the Rockies typically involves stimulation of many zones in a well with spacing intervals of up to thousands of feet. In shale formations such as the Barnett Shale, several separate fractures are carried out within the horizontal portion of the well.

In 2004, EPA completed its assessment of the potential for contamination of underground sources of drinking water by reviewing existing literature on water quality incidents that potentially were linked to hydraulic fracturing. EPA concluded there were no confirmed cases of drinking water contamination from fracturing fluid injection into CBM wells or from subsequent underground movement of fracturing fluids.

Chemical compositions, and environmental impacts, of produced water vary significantly depending on the geologic characteristics of the reservoir producing the water and the separation and treatment technologies used.[11]

Table 3 shows the amount of produced water from oil and gas extraction activities in Region 8 by state for 2002.[12] Almost 3 billion barrels of produced water were discharged in Region 8, almost 75% of which was in Wyoming.

Table 3

Produced Water by State 2002

State	Barrels
Colorado	348,255,005
Montana	123,397,156
North Dakota	98,537,154
South Dakota	8,108,174
Utah	136,296,362
Wyoming	2,091,105,179
Total	2,805,699,030

Source: U.S. Environmental Protection Agency

Oil wells generally discharge more produced water than gas wells. The category "oil with gas wells" (where "associated gas" is also produced) constituted the largest contributor of produced water in Region 8, as shown in Table 4. Oil-only wells released the second largest amount of produced water. Combined, these two well types account for 69% of total produced water in the region. Wyoming is the primary source of produced water in the region for both well types.

In managing produced water, E&P operators use a variety of technologies and techniques. A common approach involves using gravity to separate water from the recovered oil in storage tanks at a production site. The produced water then is stored in separate tanks prior to disposal or beneficial reuse. In some instances, produced water is injected back into formations to be used in enhanced oil and gas recovery.[13] The potential for reusing the water, and relevant environmental impacts, largely depends on the salinity and chlorine content of the water, as well as contaminant concentrations. For example, produced water can contain a mixture of inorganic and organic compounds, and, in many cases, residual chemical additives that are added into the hydrocarbon production process.[14]

Table 4

Produced Water by Well Type 2002 (Barrels)

State	Oil-Only Wells	Gas-Only Wells	Oil with Gas Wells	Gas with Oil Wells	Total
Colorado	81,962,976	158,856,545	102,323,995	5,111,489	348,255,005
Montana	50,775,321	16,847,685	55,708,537	65,613	123,397,156
North Dakota	20,953,673	3,521	74,617,442	2,962,518	98,537,154
South Dakota	915,122	614	5,121,998	2,070,440	8,108,174
Utah	21,684,832	31,145,993	79,283,960	4,181,577	136,296,362
Wyoming	601,234,810	569,061,152	853,631,461	67,177,756	2,091,105,179
Total	777,526,734	775,915,510	1,170,687,393	81,569,393	2,805,699,030

Source: U.S. Environmental Protection Agency

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These water quality characteristics determine whether the water can be discharged into local rivers and streams or used for irrigation, or must be treated or specially disposed of. Treatment can include evaporation ponds or processing the water to reduce its salinity. This complex issue includes the volume of water being produced, the rate of flow of the streams (e.g., ephemeral or perennial), and the compositional characteristics of the water.

EPA regulates discharges associated with offshore oil and gas activities on the outer continental shelf under the National Pollutant Discharge Elimination System (NPDES) program. Issued permits include Clean Water Act requirements, as well as EPA's guidelines for determining the degradation of marine waters. In addition, new source discharges are subject to provisions of the National Environmental Policy Act.

Waste Generation and Management

After produced water, nonhazardous solid wastes are the second-largest category of wastes resulting from E&P operations. These wastes contain mud, rock fragments, and cuttings from the wellbore, as well as chemicals added to improve drilling-fluid properties. Drilling fluids are used to control downhole pressure, lubricate the drill bit, condition the drilled formations, provide hydraulic pressure to aid drilling, and remove cuttings from the wellbore. Drilling fluid is pumped down the drill pipe and circulated back to the surface where the rock cuttings are removed and the drilling fluid is recirculated.

Devon Increasing Its Water Conservation Efforts

Devon Energy Corporation, WY, is deploying mobile recycling technology to reclaim wastewater produced from gas well completions in the Barnett Shale field. Recycling units treat up to three-quarters of a million gallons of water per day, removing hydrocarbons, dissolved salts, and other impurities, and allowing reuse of 85% of the water. Devon uses freshwater produced from coal bed natural gas wells to create lakes and ponds suitable for wildlife and livestock. Devon received the Wyoming Game and Fish Department's Coal Bed Methane Natural Resource Stewardship Award in 2002 and the Department's Industry Reclamation and Wildlife Stewardship Award in 2004.[15]

Table 5 shows estimated amounts of drilling wastes in Region 8 in 2002.[16] Oil and gas companies can minimize drilling wastes and their environmental impacts through recycling and reuse of certain drilling byproducts, the use of nontoxic drilling fluids, and the employment of a closed-loop drilling fluid system to manage fluid wastes. Potential groundwater contamination from drilling fluids and the amount of area used for disposal of such wastes are also important impacts.

The industry uses water-based and oil-based drilling fluids. Drilling fluids typically are stored at the well site in lined reserve pits or closed-loop systems, depending upon geologic and hydrologic conditions and state requirements. Used drilling fluids typically are disposed of in injection wells or are reformulated and reused. Cuttings typically are collected and stored in lined pits and may be buried onsite (after dewatering), landfilled, or used in agricultural applications depending upon geologic and hydrologic conditions and individual state requirements. Treated drill cuttings have been used beneficially as fill material; daily cover material at landfills; and aggregate or filler in concrete, brick, or block manufacturing. Construction applications for drill cuttings include use in road pavements, asphalt, and in manufacturing cement.

Table 5
Estimated Drilling Wastes 2002

State	Barrels
Colorado	6,138,174
Montana	2,741,195
North Dakota	1,484,341
South Dakota	37,451
Utah	4,533,724
Wyoming	10,834,600
Total	25,769,484

Source: U.S. Environmental Protection Agency

Other E&P wastes include:

- **Oily soil:** Soil contaminated with oil, usually resulting from equipment leaks and spills.
- **Tank bottoms:** Heavy hydrocarbons, sand, clay, and mineral scale that deposit in the bottom of oil and gas separators, treating vessels, and crude oil stock tanks.
- **Workover fluids:** Produced from well control, drilling, or milling operations, and stimulation or cleanup of an oil and gas-bearing formation.
- **Produced sand:** Sand and other formation solids built up in the wellbore in both producing and injection wells.
- **Pit and sump waste:** Heavy materials settled on the bottom of pits or sumps used to store production fluids. These materials must be removed.
- **Pigging waste:** Produced when pipelines are cleaned or "pigged." The waste consists of produced water, condensed water, trace amounts of crude oil, and natural gas liquids. It may contain small amounts of solids such as paraffin, mineral scale, sand, and clay.
- **Normally occurring radioactive material:** Occurs where extraction causes a concentration of naturally occurring radiation beyond normal background levels.

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Petroleum refining

Latest Environmental Statistics for Refining[17]

Energy Use: 3.1 quadrillion Btu

Emissions of Criteria Air Pollutants: 832,000 tons

Releases of Chemicals Reported to TRI: 66.1 million lbs.

- air emissions: 42.2 million lbs.
- Water Discharges: 17.7 million lbs.
- Waste Disposals: 6.3 million lbs.
- *Recycling, Energy Recovery, or Treatment: 1 billion lbs.*

Hazardous Waste Generated: 5.1 million tons

Hazardous Waste Managed: 5.1 million tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Energy Use

Petroleum refining operations consumed 3.1 quadrillion Btu in 2002.[18] The most energy-intensive processes include distillation, hydrotreating, alkylation, and reforming.[19] After removing salt content from the crude oil feedstock, refiners use atmospheric or vacuum distillation to separate components with varying boiling points. They then restructure the hydrocarbon molecules. Processes such as hydrotreating remove various constituents (e.g., sulfur, nitrogen, and heavy metals) to produce cleaner burning products. Finally, refiners blend the previously distilled fractions of oil into finished products.

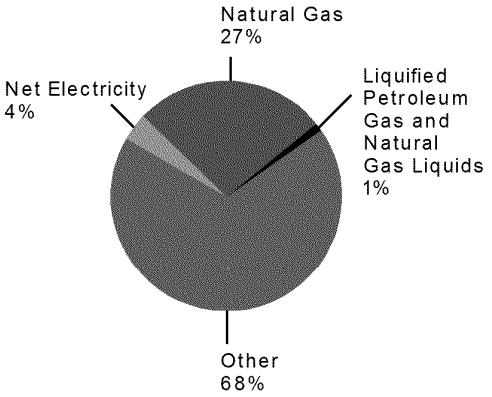
Various factors influence the energy required to refine petroleum, including individual product specifications. For example, certain markets require particular blends, or "boutique" fuels. Under the Clean Air Act (CAA), State Implementation Plans may specify using cleaner burning fuels in select locations. Producing those custom fuels generally requires significant energy inputs into the refining process. In addition, national requirements such as those in ultra-low sulfur diesel fuel standards require significant amounts of energy to reduce the sulfur content within the crude feedstock.

Higher sulfur crude oil is increasingly a primary feedstock for refiners, and that trend is likely to increase in the coming decade and beyond, given the relative availability and affordability of these inputs. In response, U.S. refiners have invested in technology to remove sulfur more efficiently. These investments will also enable refiners to meet tightening fuel specification standards to improve air quality.[20]

Figure 1

Fuel Use for Energy 2002

Total: 3.1 quadrillion Btu



Notes:
1. Other is primarily from refinery gases, generation from renewables and net steam (the sum of purchases, generation from renewables, and net transfers).
2. Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

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Refinery fuel gas (also called still gas), catalyst coke, and natural gas are the primary fossil fuels consumed by refiners, as shown in Figure 1.[21] Refinery fuel gases, represented by "other" in the figure, result from various petroleum refinery processes such as crude oil distillation, cracking, reforming, and treating. These gases are collected and processed to recover propane or other light hydrocarbons. Refiners then remove sulfur and nitrogen compounds. This cleaner gas is a mixture of CH_4, ethane, and lesser amounts of hydrogen and light hydrocarbons with trace amounts of ammonia and H_2S.

For steam production, petroleum coke, resulting from the coking process, is a free fuel of choice. Petroleum coke, primarily from the fluid catalytic cracking unit (FCCU), is burned continuously to regenerate the FCCU catalyst, with the heat of combustion captured in a steam boiler. The main supplemental fuel for steam generation is natural gas.

Some refineries are major cogenerators of steam and electricity. Cogeneration, or combined heat and power (CHP), increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source. As a result of cogeneration, purchased electricity (primarily used to power machines) is not as significant a source of indirect emissions attributed to petroleum refining as it is in other energy-intensive industries that do not produce their own electricity.

Other factors have influenced efficiency gains in refining plants. Consolidation has resulted in an industry dominated by a relatively small number of large, vertically integrated companies operating multiple facilities.[22] A result of this consolidation was the closing of smaller, less efficient plants over some time. Refineries have maintained a utilization of capacity between 90% and 95% between 1996 and 2005, compared to a rate of about 65% in the early 1980s.[23]

ExxonMobil Decision Tools for Increased Efficiency

In 2000, ExxonMobil developed its Global Energy Management System for energy conservation. Since then, the company's Baton Rouge Refinery has implemented a program for steam trap and steam leak repair, heat exchanger monitoring, and furnace air pre-heater upgrades, improving the refinery's energy efficiency by 12%. In addition, Exxon has achieved reductions in CO_2 and NO_X emissions, improved flare system reliability, increased capacity, and enhanced plant-wide reliability. The refinery received EPA's ENERGY STAR Award for these improvements.[24]

Air Emissions

Air emissions from petroleum refining include CAPs, GHGs, and chemicals reported to TRI. In general, the "toxic chemicals" tracked by TRI are found in the raw materials and fuels used in the refining process, and can be generated in byproducts or end products. CAPs and GHGs are generated as combustion byproducts from onsite combustion of fuels.

Air Emissions Reported to TRI

In 2005, 163 facilities[25] in the petroleum refining industry reported 42.2 million lbs. of absolute air emissions to TRI. Between 1996 and 2005, TRI-reported air emissions declined by 31%, as shown in Figure 2a. When normalized by crude oil inputs into refineries, air emissions decreased by 36% over the 10 years, as shown in Figure 2b.[26]

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. As shown in Figures 2b and 2c, while the normalized reported lbs. of TRI emissions to air decreased 36% since 1996, the normalized Toxicity Score increased overall by 50%. Sulfuric acid, which has a relatively high toxicity weight, drove the Toxicity Score over the 10-year period and accounted for approximately three-quarters of the 2005 Toxicity Score. Sulfuric acid resulting from petroleum refinery operations is related to sulfur dioxide (SO_2) emissions. The presence of sulfur compounds in many refinery processes, together with high temperatures, can result in the formation and release of sulfuric acid. Decreases in refinery SO_2 emissions, then, result in corresponding decreases in the generation of sulfuric acid.

The TRI list of toxic chemicals includes all but six of the HAPs regulated under the CAA. Refinery processes emit a variety of organic, inorganic, and metal HAPs. Process vents, storage vessels, and wastewater streams emit organic HAPs, accounting for most of the total mass of HAP emissions from petroleum refineries. Other sources of HAP emissions are loading racks, marine tank vessel loading operations, and equipment leaks. In absolute pounds, HAPs accounted for 46% of the TRI chemicals emitted to air and 28% of the Toxicity Score in 2005. Between 1996 and 2005, the trend for HAP emissions follows the same declining trend as for all TRI air emissions.[27]

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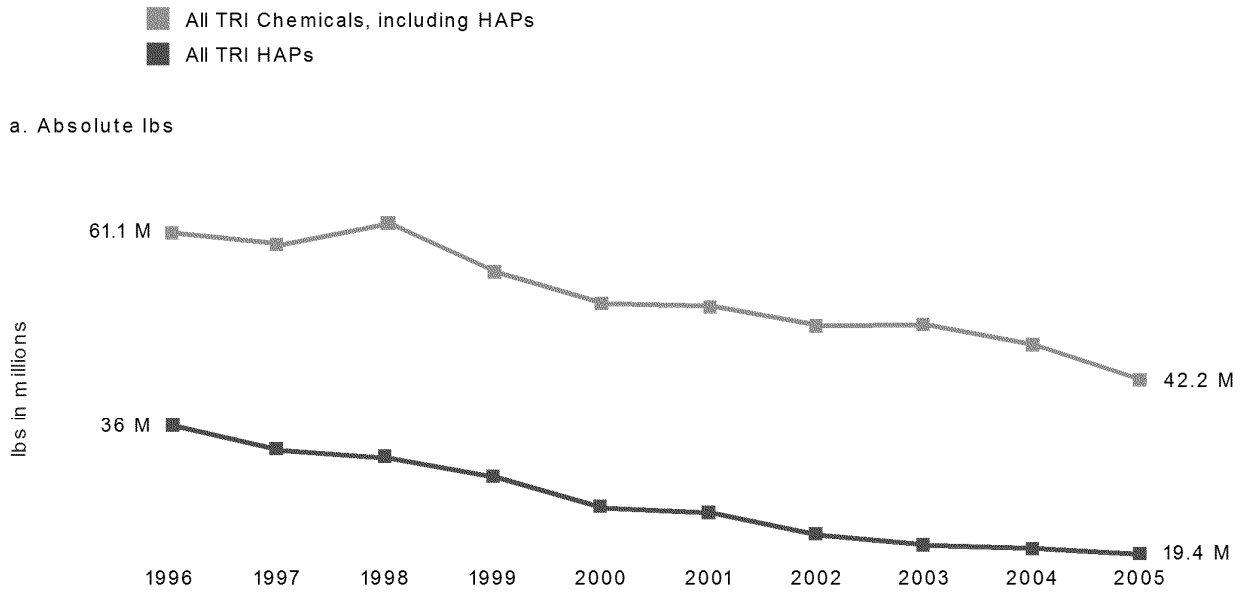
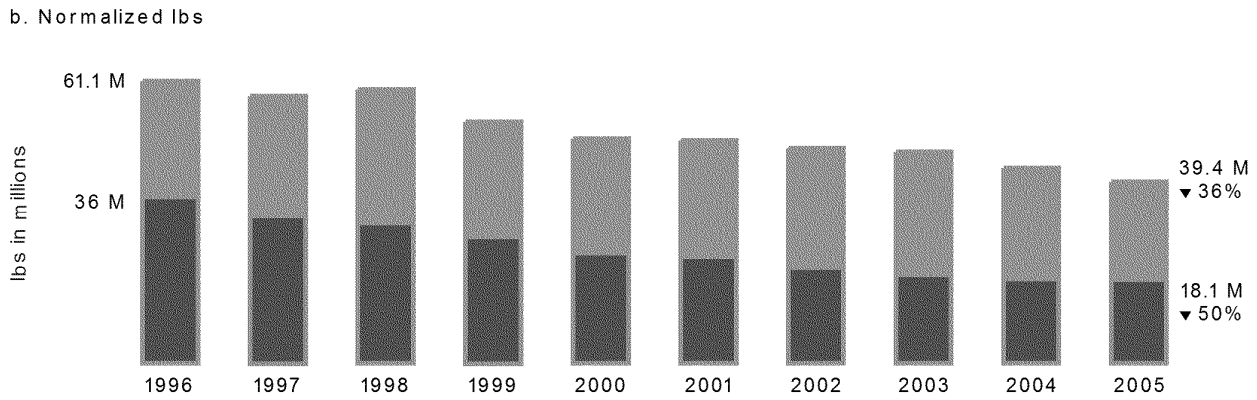
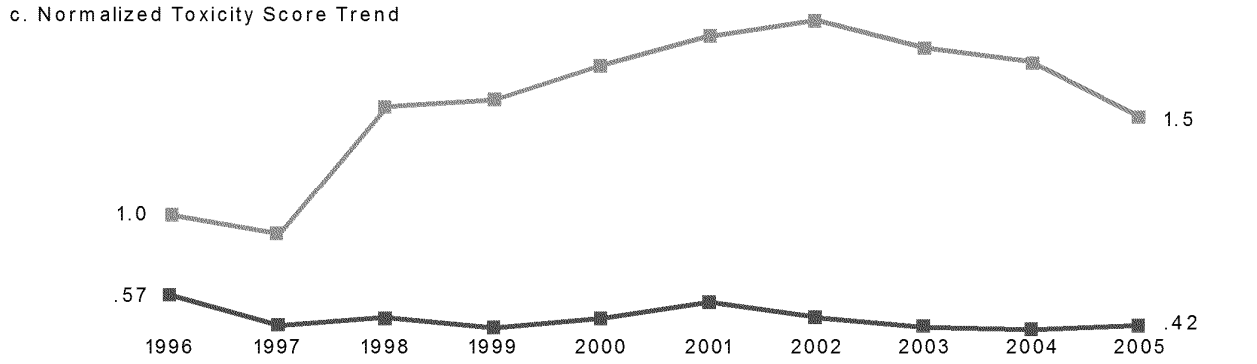
Figure 2

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual crude oil inputs into refineries.

Sources: U.S. Environmental Prote tion Agency, US Department of Energy

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Table 6 presents the top TRI-reported chemicals emitted to air by petroleum refineries in 2005, based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Ammonia and sulfuric acid were the top-ranked chemicals based on the pounds of each chemical emitted to air in 2005.
2) Percentage of Toxicity Score. Sulfuric acid was the top-ranked chemical based on Toxicity Score.
3) Number of Facilities Reporting. Benzene and toluene were the most frequently reported chemicals, with almost all the TRI filers in the sector reporting emissions of these chemicals.

The CAA requires refineries to implement a Leak Detection and Repair (LDAR) program to monitor and fix equipment leaking fugitive emissions. In 1997, API commissioned a study of 11.5 million refinery components. The study showed more than 90% of controllable fugitive emissions are from about 0.1% of all components. Analyses also indicated that "Smart LDAR" programs focused on finding and repairing these few high-leak areas could result in significant improvements in environmental performance.

Some Smart LDAR techniques use emerging optical imaging technologies to target significant leakers, with remote sensing and real-time detection capabilities to scan process areas containing potential leaks. Significant leaks are then detected on the spot using infrared light, facilitating rapid repairs and minimizing potential environmental, safety, and health impacts.

Table 6
Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage Toxicity Score	Number of Facilities Reporting[2]
Ammonia	8,574,000[3]	1%	107
Benzene[4]	2,099,000	1%	152
Chlorine	146,000	6%	36
Chromium	4,000	2%[5]	20
Ethyl Benzene	624,000	<1%	145
N-Hexane	4,146,000	<1%	147
Nickel	45,000	8%	65
Polycyclic Aromatic Compounds	67,000	5%	129
Propylene	3,121,000	<1%	113
Sulfuric Acid	8,015,000	70%	67
Toluene	3,785,000	<1%	150
Xylene	2,652,000	<1%	147
Percentage of Sector Total	**79%**[6]	**93%**[7]	**98%**[8]

Notes:
1. Total sector air releases: 42 million lbs.
2. 163 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
5. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
6. Chemicals in this list represent 79% of the sector's air emissions.
7. Chemicals in this list represent 93% of the sector's Toxicity Score.
8. 98% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Criteria Air Pollutants

Table 7 shows CAP and VOC emissions from petroleum refineries for 2002.

Table 7
Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	339,000
NO_X	195,000
PM_{10}	28,000
$PM_{2.5}$	23,000
CO	145,000
VOCs	125,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Greenhouse Gases

The combustion of fossil fuels generates direct GHG emissions from petroleum refineries, and steam production and process heating are the two processes requiring the greatest combustion. In CH_4 emissions, petroleum refiners released an estimated 28.4 million metric tons of CO_2 equivalent in 2005, an increase of 7% since 1996.[28] Within refineries, vented emissions account for about 87% of the GHG emissions, while fugitive and combustion emissions account for 6% and 7% respectively. Most fugitive CH_4 emissions are leaks from the fuel gas system.[29]

In response to the U.S. Department of Energy's Climate VISION program, API began a Climate Challenge in which member refineries have committed to improve in energy efficiency 10% by 2012. Representative activities include developing GHG emissions management plans, setting numerical targets for improving energy efficiency, and reducing emissions. Specific strategies include expanding cogeneration, gasifying refinery residuals for use as fuel, reducing venting and flaring as well as fugitive methane emissions, conducting research and development into carbon sequestration and storage, deploying renewable

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energy technologies, and improving methods for tracking GHG emissions.

Water Use and Discharges

Petroleum refiners use 1-2 billion gallons of water daily, principally for process cooling systems.[30] Because they use relatively large volumes of water, refineries are often located near water sources (e.g., beside riverbanks and other shoreline locations).

Refinery operations generate process wastewater as well as surface water runoff. Wastewater characteristics and quantities differ among facilities and are driven by individual petroleum refining configurations. Processes to refine heavy crude, for example, tend to generate significant amounts of ammonia and suspended solids. In 2005, 121 refineries reported water discharges of TRI chemicals totaling 17.7 million pounds. This was a 52% increase in reported absolute pounds since 1996, and a 42% increase overall, when normalized by crude oil inputs to refineries. Nitrate compounds, reported by 62 facilities, and ammonia accounted for almost all (97%) of the reported discharges.[31]

Wastewater from petroleum refining typically requires multiple steps to remove contaminants, recover product, and recycle process fluids prior to discharge. Refiners often lessen discharge quantities, treatment burdens, and associated costs by separating the various waste streams of cooling and process water, sanitation and sewage, stormwater, and other streams.In addition to being regulated for direct discharges and discharges to Publicly Owned Treatment Works, refineries with materials exposed to precipitation are regulated for stormwater runoff, sometimes under a general permit that provides sector-specific limits on pollutants such as zinc, nickel, lead, ammonia, nitrates, and total suspended solids.

Waste Generation and Management

Wastes from petroleum refining operations can be generated from process-related functions or other activities, such as pollution prevention (e.g., control devices) or remediation of contamination. Refineries also generate wastes from handling petroleum products and treating wastewater. Typical refinery wastes are sludges, spent caustics, spent process catalysts, filter clay, and incinerator ash.

Hazardous Waste Management

In 2005, the sector reported generating 5.1 million tons of hazardous waste. The hazardous waste management method most utilized in refining was disposal, which accounted for 84% of wastes managed in 2005.

Waste Management Reported to TRI

In 2005, refineries reported a total of 1 billion absolute pounds of chemicals released, disposed, or managed through treatment, energy recovery, or recycling. This was a 22% decrease in the reported amount of waste managed since 1996, when normalized by crude oil inputs to refineries.

Figure 3 shows how this waste was managed. In 2005, 54% was treated, 23% was recovered for energy use, and 17% was recycled, while 6% of TRI-reported waste was disposed or released. Energy recovery appeared to be the principal waste management method early in the decade; treatment was the predominant management method in recent years, accounting for 54% of the total pounds of TRI chemicals managed in 2005. Flaring is presently a major means of onsite treatment at many petroleum refineries; the industry is addressing associated GHG emissions under API's Climate Challenge.

In 2005, refineries reported that 6.3 million lbs. of TRI chemicals were disposed to land or transferred to offsite locations for disposal. Ammonia, zinc, and nickel disposals accounted for almost half of the total pounds disposed, as shown in Table 8. Most petroleum refinery TRI hazardous waste disposals utilized underground injection, although 43% relied upon landfill disposal.[32]

Table 8

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Ammonia	1,337,000[3]	29
Asbestos (Friable)	730,000	2
Benzene	107,000	98
Ethylbenzene	22,000	100
Lead	187,000	111
Molybdenum Trioxide	440,000	32
Nickel	817,000	64
Toluene	127,000	101
Xylene (Mixed Isomers)	105,000	104
Zinc	826,000	32
Percentage of Sector Total	**74%**[4]	**81%**[5]

Notes:
1. Total sector disposals: 6.3 million lbs.
2. 163 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 74% of the sector's disposals.
5. 81% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

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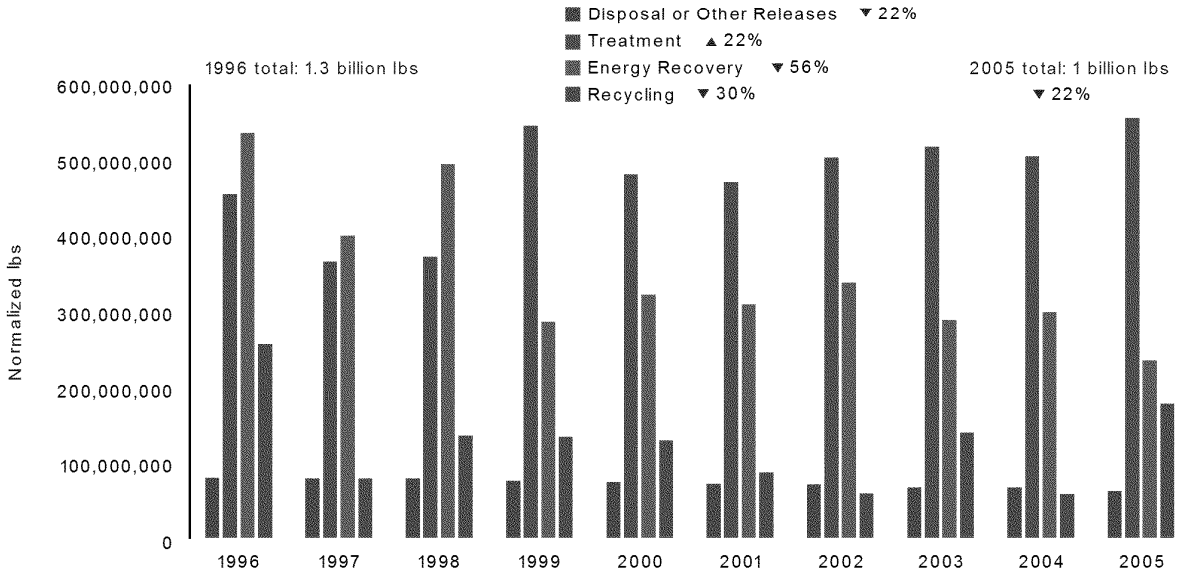
Figure 3

TRI Waste Management 1996–2005



Notes:
1. Normalized by annual crude oil inputs into refineries.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Department of Energy

Additional Environmental Management Activities for E&P and Refining

Several Oil & Gas sector environmental initiatives include both E&P and refining operations. For instance, EPA's Natural Gas STAR program engages all segments of the natural gas industry—production, gathering, processing, transmission, and distribution—to identify and implement technologies and practices to reduce emissions of CH_4. Natural Gas STAR identifies best management practices (BMPs) selected through a collaborative process involving EPA and natural gas industry advisers. The BMPs identify areas of operation where emissions can be reduced cost effectively.

In 1999, Natural Gas STAR producer partners reported saving 17.4 Bcf of CH_4, representing emissions that were prevented and natural gas that was retained in the system to be sold. EPA expanded the program in 2000 to include companies that gather and process natural gas. In 2005, partners reported more than 33.2 Bcf of CH_4 emissions reductions.[33]

The American Exploration & Production Council (AXPC) is an official endorser of the Natural Gas STAR program, in which 16 AXPC member companies actively participate. Implementing Natural Gas STAR–recommended technologies and management practices, these AXPC member companies collectively reduced CH_4 emissions by 103 Bcf, representing savings of $720 million.

Marathon's Multi-Media Environmental Management Approach

Marathon Petroleum Company–Louisiana Refinery Division in Garyville, LA, is the last petroleum refinery built in the United States (1976) and the only refinery in EPA's Performance Track program.[34] In 2005, Marathon-Garyville announced plans for a major expansion to add 185,000 barrels per stream day of crude oil capacity. During the permitting process, Marathon agreed to reduce NO_x emissions beyond Best Achievable Control Technology requirements and to impose CO limits below burner manufacturer specifications. Marathon also installed four real-time ambient air monitoring stations and plans to upgrade the wastewater treatment system to ensure no additional NPDES permit allocations will be necessary. Marathon already has an onsite wastewater treatment plant that uses water from the adjacent Mississippi River and returns it to the river cleaner than it was when withdrawn.[35]

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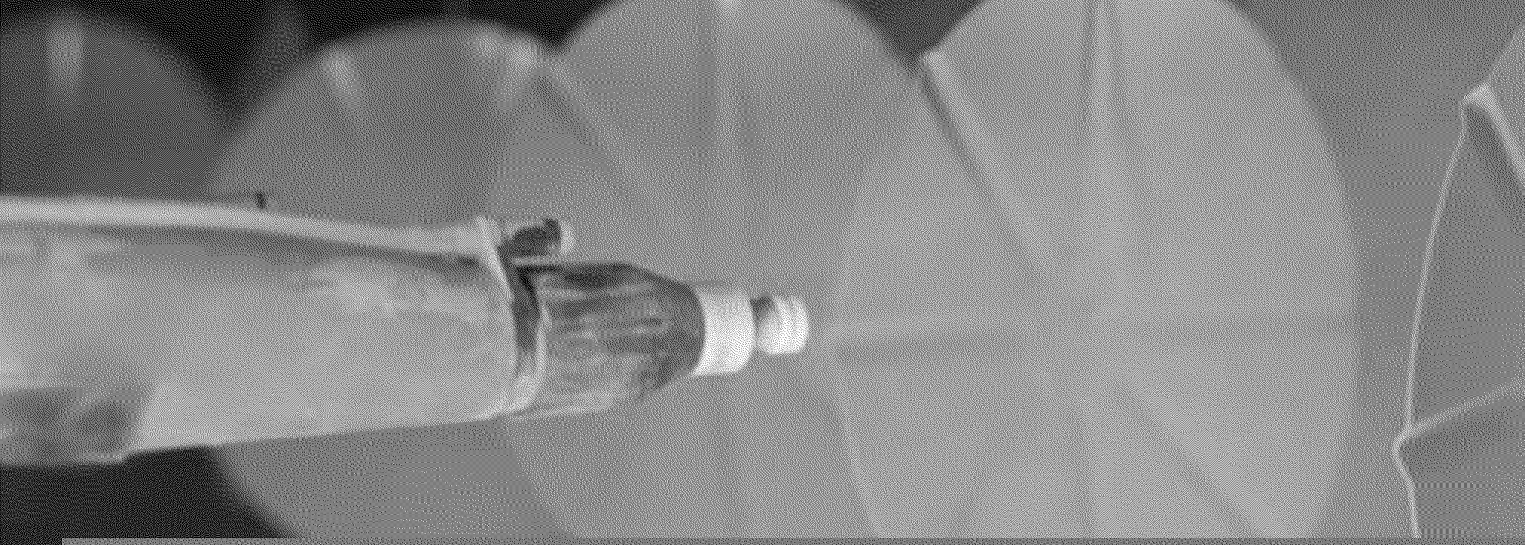
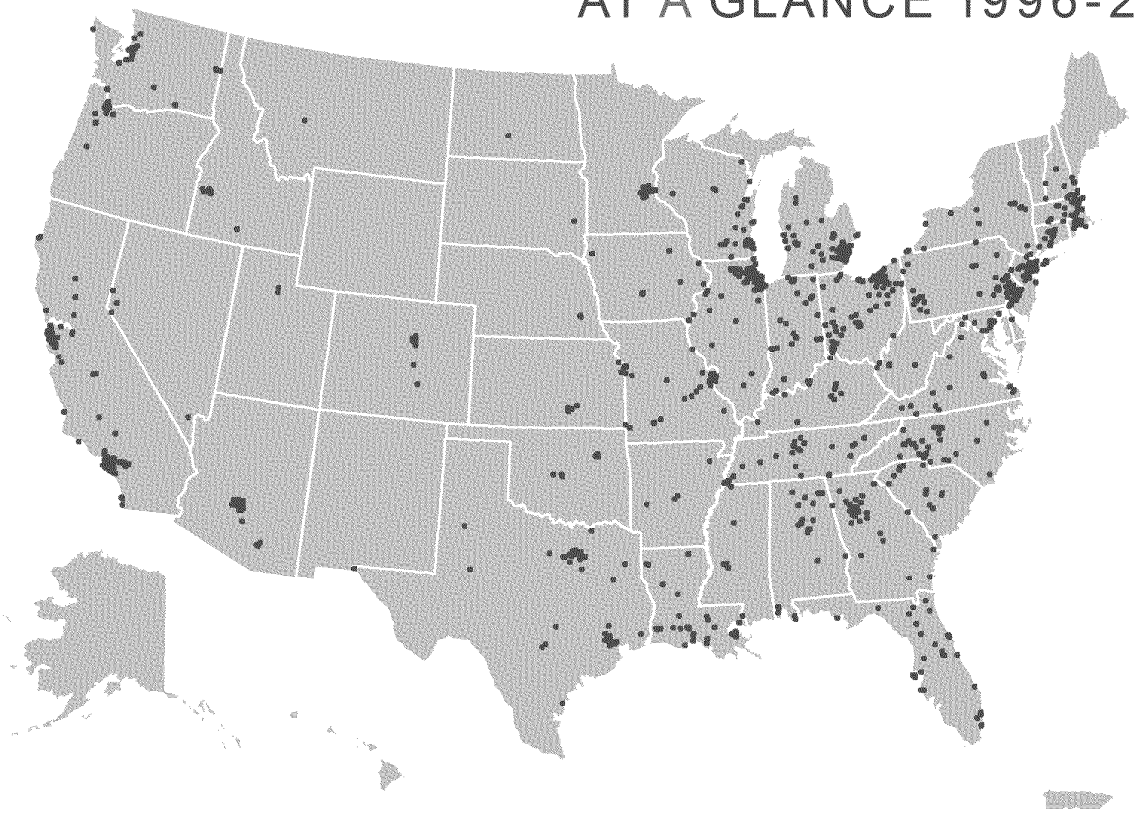
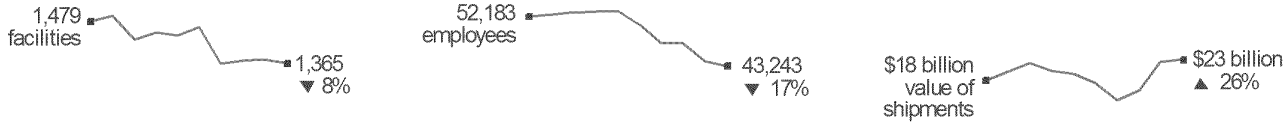


Paint & Coatings

AT A GLANCE 1996-2005[1]





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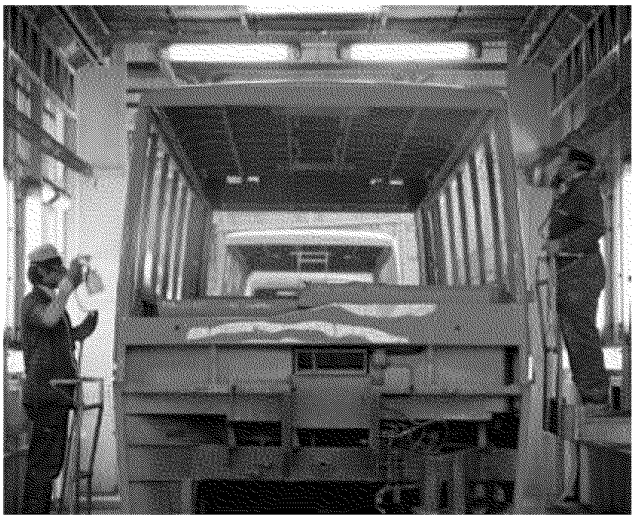

Latest Environmental Statistics[2]

Emissions of Criteria Air Pollutants: 10,300 tons

Releases of Chemicals Reported to TRI: 5.3 million lbs.

- airemissions: 4 million lbs.
- Water Discharges: 9,900 lbs.
- Waste Disposals: 1.3 million lbs.
- *Recycling, Energy Recovery, or Treatment: 116.3 million lbs.*

Hazardous Waste Generated: 146,000 tons

Hazardous Waste Managed: 148,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

The Paint & Coatings sector[3] manufactures a variety of products that preserve, protect, and beautify the objects to which they are applied. The main types of Paint & Coatings products include:

- **Architectural coatings**—interior and exterior paints, primers, sealers, and varnishes.
- **Industrial coatings**—factory-applied to manufactured goods during production.
- **Special-purpose coatings**—aerosol paints, marine paints, high-performance coatings, and automotive refinish paints.
- **Allied paint products**—putties, paint and varnish removers, paint thinners, pigment dispersions, paint brush cleaners, and frit (ground glass or glaze).

Energy Use

In 2002, the Paint & Coatings sector purchased about 1.6 billion kilowatt hours of electricity for heat and power, which represented well under 1% of the total quantity of electricity purchased for heat and power by U.S. manufacturers.[4] Data on fossil fuel consumption are not currently available.

Air Emissions

Air emissions from the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in the raw materials used as formulation ingredients in the manufacturing process.

Air Emissions Reported to TRI

In 2005, 441 facilities in this sector reported 4 million lbs. of absolute air emissions to TRI. Between 1996 and 2005, absolute TRI-reported air emissions declined by about 57%, as shown in Figure 1a. When normalized by the value of shipments VOS over this period, air emissions declined by about the same amount, as seen in Figure 1b. The normalized and absolute data are similar because production remained relatively steady over the period.

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated

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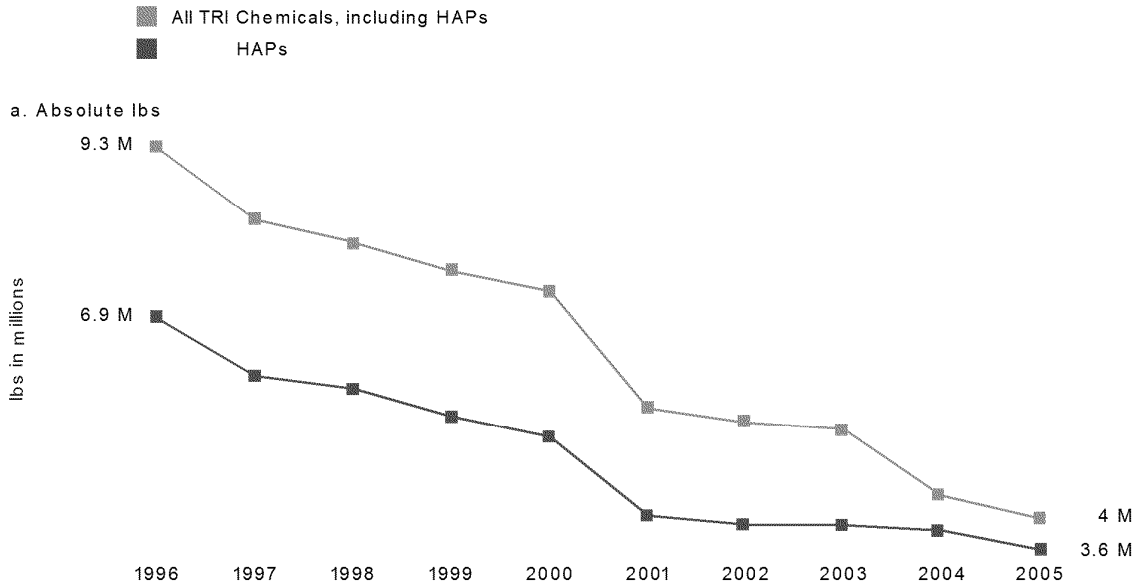
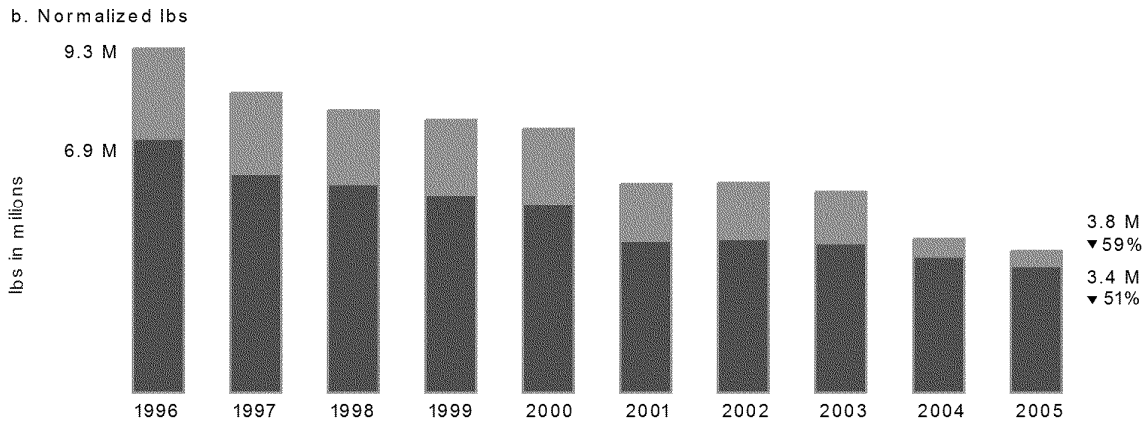
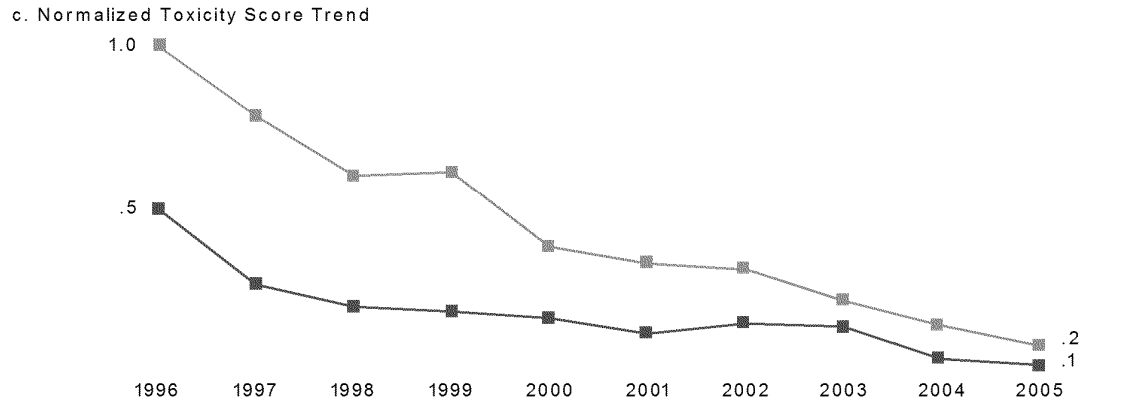
Figure 1

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual value of shipments.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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in Figure 1c. The sector's total Toxicity Score, normalized by value of shipments, declined by more than 80% from 1996 to 2005.[5]

The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. In absolute pounds, HAPs accounted for most (90%) of the sector's pounds of air emissions reported to TRI in 2005; therefore, trends in HAP emissions showed very similar declines to the trends in air emissions for all TRI chemicals when based on either pounds reported or the Toxicity Scores.[6]

Table 1 presents the top TRI-reported chemicals emitted to air by the sector based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Xylene and toluene, organic solvents used as carriers in paints, were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005.

Table 1
Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage Toxicity Score	Number of Facilities Reporting[2]
1,2,4-Trimethylbenzene	142,000	14%[3]	113
Certain Glycol Ethers	232,000	7%	193
Chromium	860	24%[4]	29
Diisocyanates	140	8%[5]	10
Ethyl Benzene[6]	215,000	<1%	136
Methanol	408,000	<1%	68
Methyl Isobutyl Ketone	189,000	<1%	114
Nickel	1,400	16%	6
Toluene	859,000	<1%	216
Xylene (Mixed Isomers)	1,140,000	7%	275
Percentage of Sector Total	**80%**[7]	**75%**[8]	**82%**[9]

Notes:
1. Total sector air releases: 4 million lbs.
2. 441 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. The toxicity score for chromium was based on the conservative assumption that all of the chromium air emissions by TRI reporting facilities in the Paint and Coatings sector are hexavalent chromium. EPA's National Emissions Inventory estimates that only 25% of the chromium emissions from this sector are hexavalent chromium, and the balance are trivalent chromium, which has a substantially lower toxicity weight.
5. The toxicity score for diisocyanates was based on the conservative assumption that all of the diisocyanates emitted to air by TRI reporting facilities in the Paint & Coatings sector are hexamethylene diisocyanate. Preliminary analysis indicates that methylene diphenyl diisocyanate, and other diisocyanate chemicals that have lower toxicity weights, may constitute the majority of the reported diisocyanate emissions from this sector.
6. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
7. Chemicals in this list represent 80% of the sector's air emissions.
8. Chemicals in this list represent 75% of the sector's Toxicity Score.
9. 82% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

2) Percentage of Toxicity Score. The top chemicals based on Toxicity Scores included chromium, nickel, and 1,2,4-trimethylbenzene.

3) Number of Facilities Reporting. Xylene and toluene were also the most frequently reported chemicals, with approximately half of the TRI-reporting facilities in the sector reporting air emissions of each of these chemicals.

Criteria Air Pollutants

Table 2 shows CAP and volatile organic compound (VOC) emissions from the sector for more than 340 manufacturers in 2002.[7] VOCs emitted during the production and use of the sector's products have the largest impact on ambient air quality of any of the pollutants listed in Table 2. VOC emissions result primarily from the use of organic solvents to formulate paint and coating products.

Table 2
Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	50
NO_X	400
PM_{10}	600
$PM_{2.5}$	400
CO	3,000
VOCs	6,000

Notes:
1. PM_{10} includes $PM_{2.5}$ emissions.
2. The majority of CO emissions in 2002 were reported by a single fac lity.

Source: U.S. Environmental Protection Agency

Recent regulatory developments and the continuing market trend toward water-based coatings, powder coatings, ultraviolet cure coatings, and other lower-emitting coating products have contributed to reductions in VOC emissions from production in recent years. Still, VOC emissions from the sector's production activities continue to be dwarfed by VOC emissions that occur at the point of use. In 2002, Paint & Coatings manufacturers emitted 6,000 tons of VOCs, while VOC emissions resulting from the use of paint and coating products was over 2 million tons.[8]

Water Use and Discharges

Water serves as a major formulation ingredient in many of the sector's products. Water-based products include many paints, aerosols, inks, and coatings. Additionally, many types of manufacturing cleanup processes require water. The sector's wastewater is usually discharged to Publicly

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Owned Treatment Works, but may also be discharged directly to waterways, necessitating a National Pollutant Discharge Elimination System permit.

TRI tracks TRI chemicals discharged to water from those facilities in the sector subject to TRI reporting requirements. In 2005, 39 facilities in this sector reported water discharges of TRI chemicals totaling 9,900 lbs.[9] This quantity represents a decline of almost 50% between 1996 and 2005.[10] In 2000, EPA randomly surveyed 292 Paint & Coatings facilities to collect data for its Paint Production Waste Listing Determination.[11] EPA extrapolated from this survey to estimate that the quantity of wastewaters (both nonhazardous and hazardous) generated in 1998 from all facilities in the targeted paint manufacturing industry was approximately 15.6 million gallons.[12]

Waste Generation and Management

Wastes in the Paint & Coatings sector can be generated from process-related functions or from other activities, such as operation of pollution control devices or remediation of past contamination.

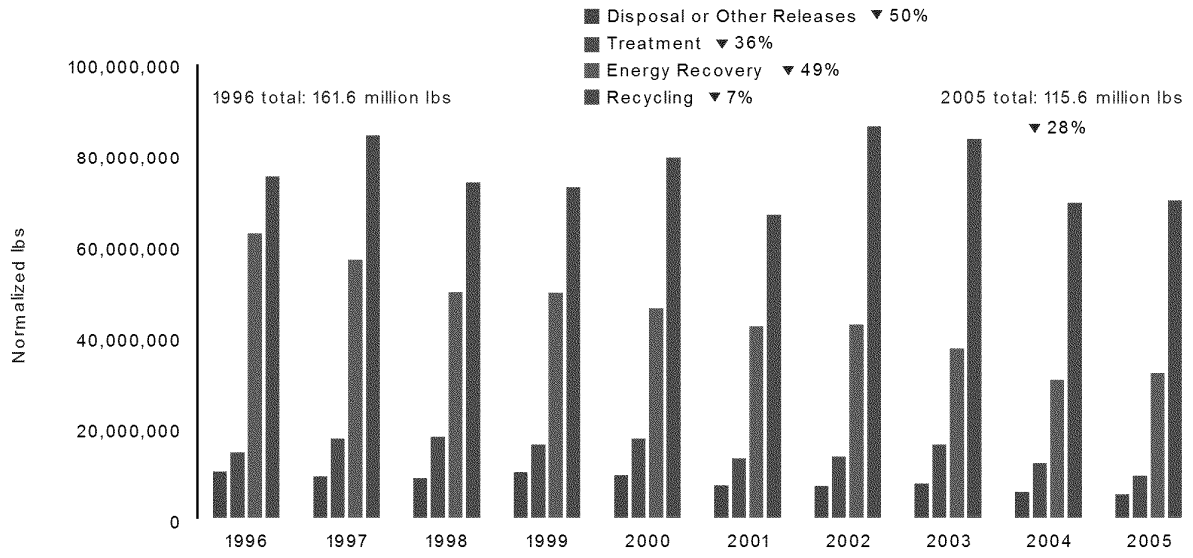
Hazardous Waste Management

In 2005, 396 Paint & Coatings manufacturers reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating 146,000 tons of hazardous waste.[13] Cleaning out equipment (e.g., cleaning out mixing tanks between batches), solvent distillation, and discarding off-spec chemicals (e.g., off-spec or out-of-date products) accounted for approximately half of the industry's hazardous waste generation. A large portion of the remaining hazardous waste generation appears to be attributable to a small number of resin or other chemical manufacturing operations that are co-located within the sector's facilities.[14] The sector reported managing 148,000 tons of hazardous waste. Most of the sector's hazardous waste, regulated by the Resource Conservation and Recovery Act (RCRA), was managed through reclamation and recovery activities (predominantly fuel blending and solvents recovery), and treatment.[15]

Waste Management Reported to TRI

In 2005, facilities in the Paint & Coatings sector reported managing 121.5 million absolute lbs. of TRI chemicals in waste. As shown in Figure 2, when normalized by annual VOS, total waste managed declined 28% between 1996 and 2005. Figure 2 also shows how the sector has managed this waste over time.[16] In 2005, 4% of the absolute pounds of TRI-reported waste was released (to air or water) or disposed, while 8% was treated, 28% was recovered for energy use, and 60% was recycled, demonstrating the importance of recycling and fuel blending (a form of energy recovery) in the sector's waste management practices.

Figure 2
TRI Waste Management 1996–2005



Notes:
1. Normalized by annual value of shipments.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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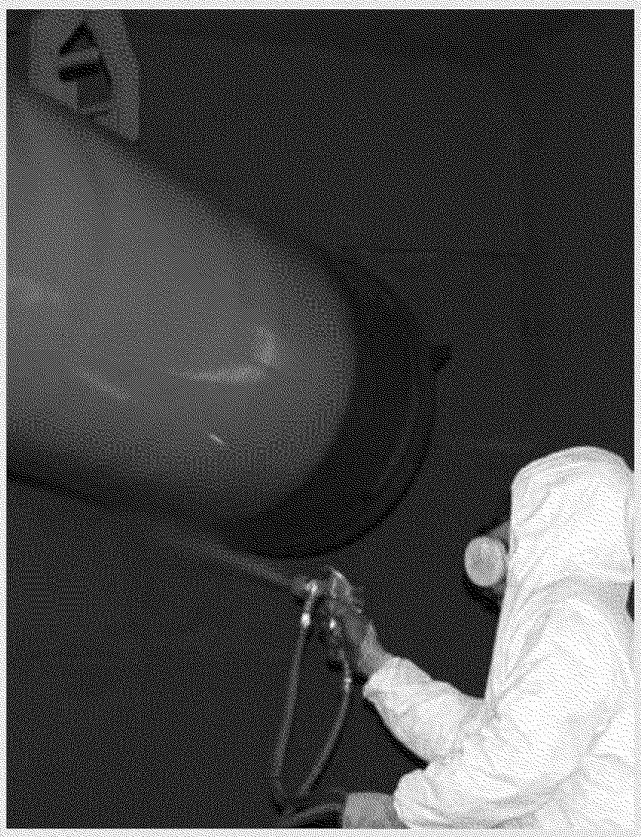

Table 3
Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Barium	163,000[3]	20
Certain Glycol Ethers	31,000	32
Chromium	79,000	32
Copper	79,000	22
DI(2-Ethylhexyl) Phthalate	93,000	4
Ethylene Glycol	86,000	31
Lead	47,000	75
Zinc	464,000	99
Percentage of Sector Total	**83%**[4]	**35%**[5]

Notes:
1. Total sector disposals: 1.3 million lbs.
2. 441 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 83% of the sector's disposals.
5. 35% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

For the 1.3 million lbs. of waste that was disposed (not including releases to air or water), zinc accounted for about one-third of the pounds disposed, as shown in Table 3. Zinc and lead were the chemicals most frequently reported as disposed by the sector.[17]

Additional Environmental Management Activities

Coatings Care® is a comprehensive stewardship program developed by the National Paint & Coatings Association (NPCA) to assist its members with integrating environmental, health, and safety (EH&S) activities into corporate planning and operations. Organizations make a commitment to Coatings Care as a required part of their membership in NPCA. Coatings Care organizes EH&S activities into five codes of management practice—Manufacturing Management, Transportation and Distribution, Product Stewardship, Community Responsibility, and Security—and NPCA provides extensive support to its members in these areas. Coatings Care integrates EH&S practices that are consistent with other industry standards, such as those found in the ISO 14000 series.[18]

In addition, since December 2003, NPCA and its members have been actively participating in the Paint Product Stewardship Initiative (PPSI), a collaborative multi-stakeholder effort to promote leftover paint management solutions that are both financially and environmentally sustainable. Unused or leftover paint is a major focus of product stewardship efforts because of its high volume in the household hazardous waste stream, its high cost to manage, and the potential for increased reduction, recovery, reuse, and recycling.[19] EPA estimates that between 6% and 16% of the household paint sold each year becomes leftover paint, with a best estimate of 10%.[20] The stakeholders have completed a $1 million joint research program and are now working to develop a new nationally coordinated system for managing leftover paint with the goal of reducing paint waste; establishing mechanisms for efficient collection, reuse, recycling, or disposal of leftover paint; and for putting in place a sustainable financing system to cover the costs of such a system.[21]

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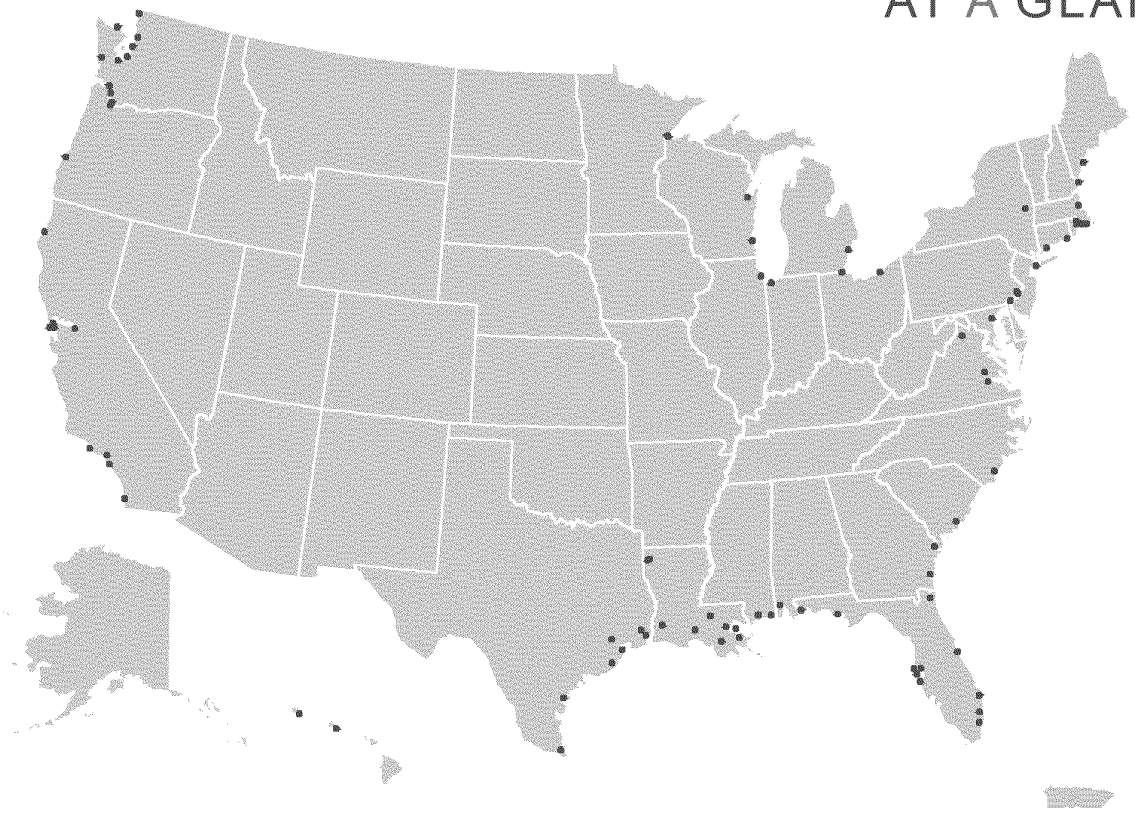
Ports

AT A GLANCE[1]



2005: 360 public and private ports; map shows large, deep water, public port authorities

1999: 422,578 employees

2006: 507,448 employees ▲ 20%

1997: $5.3 billion in revenue

2002: $6.2 billion ▲ 16%

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Latest Environmental Statistics

Because of the relative lack of sector-level data on the environmental performance of ports, this chapter relies in part on survey information that the American Association of Port Authorities (AAPA) collected in 2005 and 2007 from its U.S. members, the country's 86 largest port authorities. Thirty-eight ports completed the 2007 survey, representing a 44% response rate.[2] They represented 19 of the top 30 U.S. container ports in 2006, and 20 of the top 30 U.S. ports for total trade tonnage in 2005.[3] Although these large public ports are only one component of the U.S. port industry, they handle the majority of U.S. overseas freight. Understanding their performance is key to understanding the environmental performance of the entire sector. The chapter also highlights commitments ports are making, individually and collectively, to better understand and improve their environmental performance.

Profile

More than 360 commercial ports serve the United States with approximately 3,200 cargo and passenger handling facilities employing more than 507,000 people, contributing an estimated $1.3 trillion to the Gross Domestic Product, and generating an estimated $21.4 billion in U.S. Customs revenue.[4]

The Ports sector includes public and private marine facilities along sea coasts, on estuaries and rivers, and around the Great Lakes. Ports develop and maintain shoreside facilities for intermodal transfer of cargo between ships and other modes of transportation, such as barges, trucks, railroads, and pipelines. They may also operate other facilities, such as airports, world trade centers, and recreational facilities.

U.S. ports and waterways handle more than 2 billion tons of domestic and import/export cargo annually.[5] Ports handle 78% of all U.S. foreign trade by weight and 44% by value.[6] Forty-nine U.S. ports also have passenger cruise terminals, from which more than 9 million passengers embarked in 2006.[7]

U.S. ports are expected to experience unprecedented growth in overseas trade and continuing growth in the cruise industry. Forecasts call for a doubling in the volume of containerized cargo and in the number of cruise passengers between 2005 and 2020.[8]

Energy Use

Energy use at ports consists mainly of electricity for facility operations and fuel for vehicles and cargo-handling equipment. The most common fuel used is petroleum-based diesel, although ports are beginning to use other fuels. To reduce air emissions, some ports have switched to electric-powered cargo handling equipment, while others are using propane, liquefied natural gas (LNG), or biodiesel blends in vehicles and equipment. A few ports, including Juneau, AK, Long Beach and Los Angeles, CA, and Seattle, WA, have installed shoreside power (or "cold ironing") at some of their terminals so that oceangoing vessels can connect to the landside electric grid while at the dock rather than running their auxiliary diesel engines. The Port of Seattle has cold ironing infrastructures in place for the two berths. The Port of Oakland, CA, has successfully tested a mobile power unit that produces electricity onsite for ships at dock using LNG.[9] A 2004 study for the Port of Long Beach estimated that shoreside power would reduce nitrogen oxide (NO_X) emissions by 99% and particulate matter (PM) emissions by up to 97% per vessel, while a vessel is hotelling.[10]

Ports have some potential for fuel switching, especially if they have direct control over the diesel-powered vehicles and equipment onsite. However, even "landlord" ports, whose tenants own and operate the majority of vehicles and equipment, can influence fuel use through voluntary programs or means such as lease specifications or preferential fees when new leases are being negotiated or old leases are being renegotiated.[11]

Air Emissions

Ports have a diversity of activities and a multitude of emissions sources; there are currently no sector-level estimates of port air emissions. However, EPA is working with AAPA to encourage individual ports to prepare emissions inventories, develop and implement emission reduction strategies, and measure progress against the baseline.[12] EPA also is working with ports and other stakeholders to develop modeling tools for port-related

Increasing Use of Biodiesel

Compared to burning standard diesel, the use of biodiesel results in reductions in direct emissions of carbon monoxide (CO), PM, sulfates, volatile organic compounds (VOCs), and greenhouse gases (GHGs). In 2006, the Port of Seattle, WA, and SSA Marine, the port's largest maritime customer, switched their maintenance vehicles and container-handling equipment from standard diesel fuel to biodiesel. Another terminal operator, APL, also switched to biodiesel. Both terminal operators use B20, a blend of 20% biodiesel and 80% ultra-low-sulfur (ULSF) diesel. The port uses B99 (99% biodiesel) in its maintenance equipment. During cold periods, the port and SSA switch to lower blends of biodiesel (B50 and ULSF, respectively) to cope with gelling problems.[13] Together, the port and SSA use about 1 million gallons of fuel per year in the vehicles now powered by biodiesel.[14] Annual emissions reductions from this switch are estimated to be 2.1 tons of CO, 1.5 tons of VOCs, 0.3 ton of PM, and nearly 1,300 tons of GHGs.[15]

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Increasing Use of Solar Power

The Port of New York and New Jersey East Coast Warehouse Facility at Elizabeth Port Authority Marine Terminal has been equipped with more than 5,000 flexible solar panels, covering about 37% of its roof and designed to produce more than 810,000 kilowatts (kW) of electricity. The Ports of Oakland and Los Angeles, CA, both recently committed to deploying solar power systems onsite to supply electricity for their operations. In December 2007, the Port of Los Angeles agreed to construct a 10-megawatt solar photovoltaic system as part of the mitigation package for a major expansion of one of the port's container terminals. The port expects the system to offset nearly 17,000 metric tons of GHG emissions annually.[16] In November 2007, the Port of Oakland arranged for deployment of a new 756-kW solar photovoltaic power system on its property, which it expects to generate more than 1 million kW hours of electricity annually. The port expects the system to reduce its GHG emissions by 850 metric tons per year.[17]

air emissions. Many of the nation's ports are located in areas that do not meet EPA National Ambient Air Quality Standards for ozone (eight-hour standard) and $PM_{2.5}$.[18]

Diesel Emissions

The primary sources of air emissions from the Ports sector are diesel engines, which are used in ships, trucks, trains, cargo-handling equipment, and harbor craft. Diesel emissions include PM, NO_X, sulfur oxides (SO_X), hazardous air pollutants, and GHGs. As shown in Table 1, more ports are taking steps to quantify and reduce air emissions.

Table 1

Emission Reduction Strategies Reported by Ports

	2005	2007
Have an emissions inventory	23%	42%
Have an emissions control or reduction strategy	25%	37%
Are using low-emission fuels	29%	47%
Have implemented program for diesel retrofits or replacements	NA	34%
Are using alternative energy sources	NA	26%

Source: American Association of Port Authorities

As shown in the table, some ports are reducing emissions from existing diesel engines through engine replacements or retrofits. To assist with this effort, EPA worked with AAPA and other stakeholders to create Clean Ports USA. Launched in 2004 as part of EPA's National Clean Diesel Campaign, this incentive-based program is designed to reduce diesel emissions from existing vehicles and equipment at ports. Clean Ports USA has funded 11 port-related projects with $1.9 million in federal dollars and $2.5 million in matching funds provided by partners.[20] Ports, EPA, and other stakeholders also are collaborating through five regional partnerships that are encouraging voluntary diesel emissions reductions.

Ports With Emissions Inventories[19]

Anacortes (WA)
Baltimore (MD)
Coos Bay (OR)
Corpus Christi (TX)
Everett (WA)
Houston (TX)*
Lake Michigan Ports
Long Beach (CA)*
Los Angeles (CA)*
Lower Mississippi River Ports (LA)
New York/New Jersey (NY/NJ)*
Oakland (CA)*
Olympia (WA)
Philadelphia and Delaware River Ports (PA, DE)
Port Angeles (WA)
Portland (OR)
San Diego (CA)
Savannah (GA)*
Seattle (WA)*
South Carolina State Port Authority (SC)*
South Louisiana (LA)
Tacoma (WA)*
Tampa (FL)
Virginia Port Authority (VA)*

Note: * = top 10 U.S. container ports in 2006

Source: U.S. Environmental Protection Agency

Ports are reducing diesel emissions from trucks by implementing operational changes that reduce waiting times and the number of truck trips. One such change is the establishment of common pools for the chassis that are used to haul intermodal containers. Most chassis are owned and maintained by individual terminal operators or shipping lines, which typically do not allow them to be used with another carrier's containers. Requiring drivers to switch chassis can add up to one hour per trip, increasing fuel use and air pollution. Chassis pools reduce the number of truck movements and the amount of idling, resulting in lower emissions and greater productivity. In 2004, the Virginia Port Authority established a chassis pool at the Port of Virginia, which became the first U.S. port to achieve 100% participation from the port's shipping lines.[21] In the Port of New York and New Jersey, the Maher Container Terminal at the Elizabeth Port Authority Marine Terminal utilizes a 31-acre chassis pool yard. Ports also are

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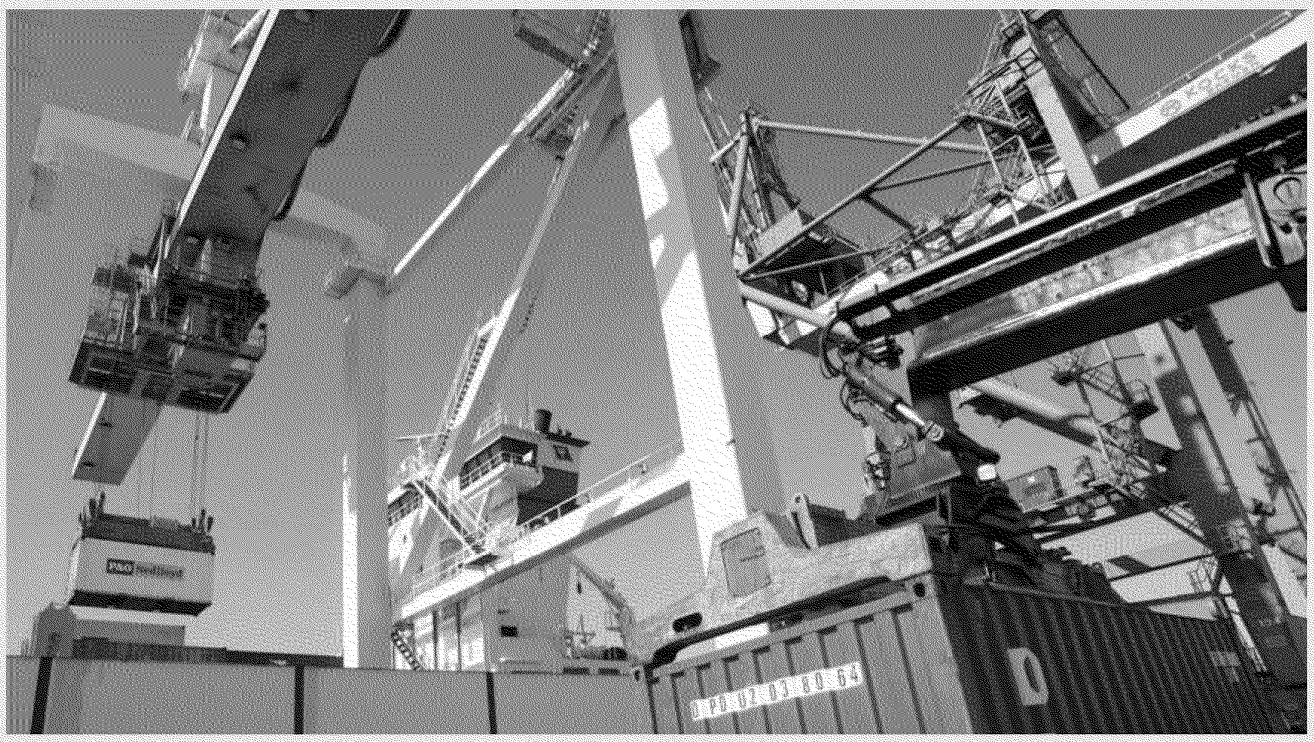

San Pedro Bay Ports Clean Air Action Plan

In November 2006, the Ports of Los Angeles and Long Beach, CA, adopted a comprehensive strategy to reduce air emissions from freight transportation in a region that has some of the worst air quality in the nation. Their goal is to reduce emissions of PM, SO_X, and NO_X (a precursor to smog) from port-related operations by 45% or more within five years.[22] By the fifth year, the ports plan to achieve annual emission reductions of 1,200 tons of PM, 12,000 tons of NO_X, and 8,900 tons of SO_X.[23] Under the plan, the ports will:

- Phase out the oldest (and therefore dirtiest) trucks servicing the ports,
- Equip all major terminals with shoreside electricity for vessels at berth,
- Require ships to use low-sulfur fuels and reduce speeds when entering or leaving the harbor region, and
- Replace or retrofit all switching locomotives and cargo-handling equipment to meet EPA's toughest emissions standards for new equipment.

The ports are actively implementing the plan. For example, all diesel-powered Class 1 switcher and helper locomotives entering the Port of Los Angeles have been using ULSF diesel fuel since the beginning of 2007.[24] The plan built upon previous efforts by the ports. For example, between 2001 and 2005, the Port of Los Angeles reduced emissions of PM, SO_X, and NO_X by 17% to 27% on a per-container basis.[25]

South Carolina State Ports Authority (SCSPA)

Even though the southeastern coast of the United States is currently in attainment with federal air quality standards, SCSPA developed a voluntary air quality program to minimize air emissions from existing terminals and a new container terminal it is building. The port committed to activities such as conducting an emissions inventory of existing facilities, funding a PM monitoring station, and including clean air guidelines in construction bid documents.[26] SCSPA also switched to ULSF diesel in September 2007, three years ahead of federal requirements.[27] Emissions reductions over those three years will be an estimated 1,100 pounds of NO_X and 30 pounds of SO_X.[28]

Northwest Ports Clean Air Strategy

The Northwest Ports Clean Air Strategy is a joint effort of the Ports of Seattle and Tacoma, WA, and Vancouver Fraser Port Authority (British Columbia) to reduce maritime and port-related emissions that affect air quality and contribute to climate change. A key goal is to stay in attainment of ambient air quality standards. The strategy establishes measurable short- and long-term performance measures for trucks, rail, water vessels, oceangoing vessels, and cargo-handling equipment.[29]

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developing retrofit and replacement programs for drayage trucks to reduce emissions.

Oceangoing vessels, which burn bunker fuel while at sea and run auxiliary diesel engines in port, are a major source of emissions at ports. The International Convention for the Prevention of Pollution from Ships (also known as MARPOL) governs vessels' environmental performance. In October 2007, AAPA's members agreed to support the U.S. government proposal to the International Maritime Organization (IMO) to amend MARPOL Annex VI and establish more stringent air emission standards for oceangoing vessels.[30]

Greenhouse Gases

There are no sector-level estimates of GHG emissions from ports, but many ports are estimating GHGs when conducting emissions inventories. For example, the Ports of Seattle, Tacoma, and Everett, WA, jointly estimated GHG emissions of 397,033 tons of carbon dioxide (CO_2) equivalent in 2005, with overall Puget Sound maritime emissions of 1.9 million tons of CO_2 equivalent.[31] The Port of San Diego, CA, a relatively small port, estimated GHG emissions of 128,000 tons of CO_2 equivalent in 2006.[32]

Increasingly, shippers are expecting organizations in the transportation supply chain to measure, report, and improve their environmental performance. For example, through EPA's SmartWay Transport Partnership, companies commit to shipping higher percentages of freight with truck and rail carriers that are SmartWay partners. In turn, participating carriers agree to estimate their emissions and reduce them over time. EPA is working with the freight industry to expand the program and develop tools that will help companies measure and reduce GHG and criteria air pollutant emissions from their entire transportation supply chain (including ports).

SmartWay already includes some drayage carriers, which are truck companies that deliver freight to and from port facilities. Seeking more ways to improve the environmental performance of drayage fleets, which typically consist of older trucks, SmartWay is working with ports such as the Virginia Port Authority to offer low-cost loans to drayage carriers for cleaner and more fuel-efficient trucks.[33]

Water Use and Discharges

Located on coasts and inland waterways, ports are caretakers for coastal resources. Public ports regularly develop wetland sites; create, restore, and enhance habitat; and monitor water quality. The transport of invasive species in ships' ballast water and oil spills from ships or landside facilities can significantly affect local water quality and wildlife. Dredging of channels and harbors can affect water quality, although dredging permits require mitigation plans.

Stormwater

Stormwater can pick up pollutants from paved surfaces before entering waterways. Most port facilities for cargo handling include large expanses of paved surface, which,

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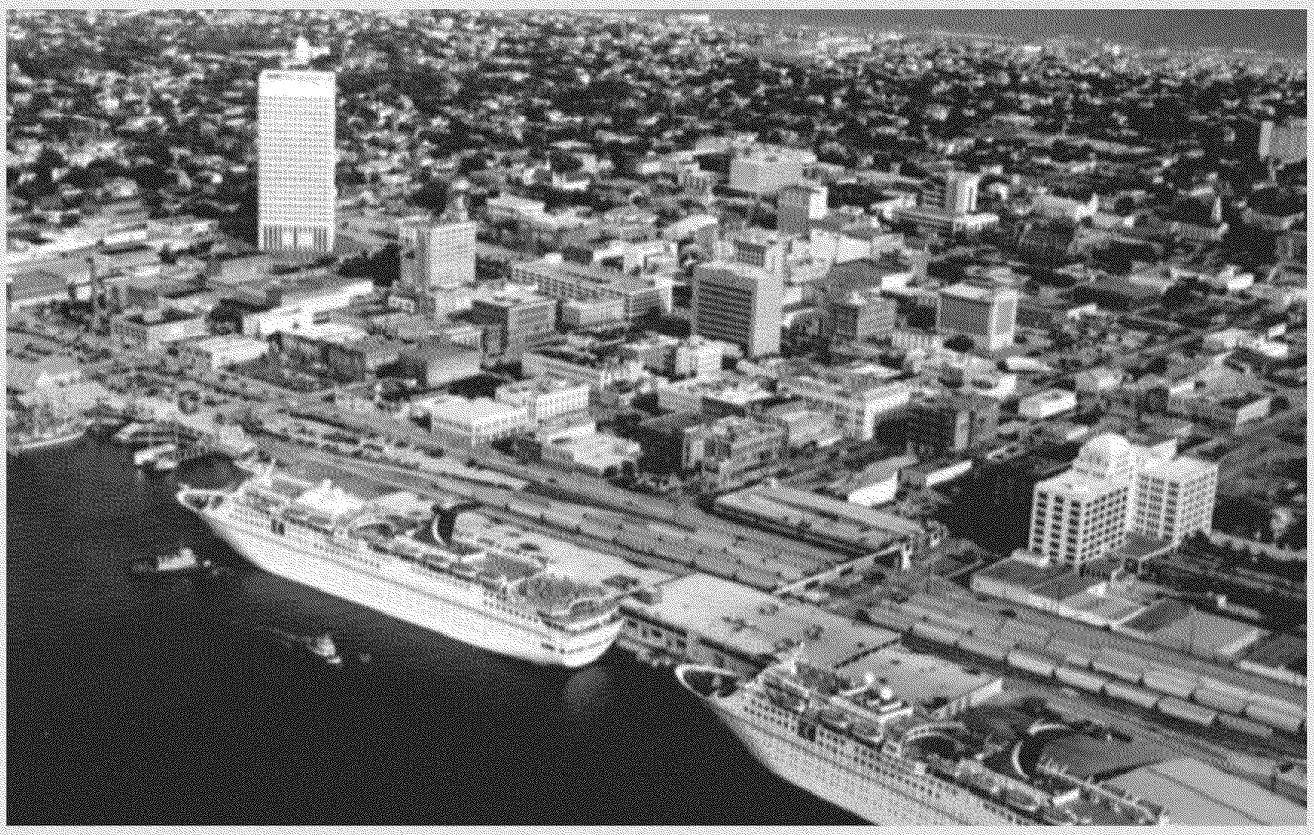

Reducing Discharges With Permeable Asphalt

In 2006, the Port of Portland, OR, installed 35 acres of porous asphalt at one of its auto-import facilities. Unlike traditional asphalt, porous asphalt allows stormwater to soak into the underlying soil. The porous asphalt, along with a system of swales and natural vegetation to handle runoff from heavy rain, treats all stormwater onsite. The port saved $250,000 and nearly a year of time for obtaining an NPDES permit. The port also receives a discount on the city's storm sewer fee and will have lower maintenance costs over time.[34]

along with the possibility of spills of bulk or liquid freight, makes stormwater management very important. Most stormwater discharges from ports are considered point sources and require a National Pollutant Discharge Elimination System (NPDES) permit. Many NPDES permits require preparation of a Stormwater Pollution Prevention Plan. In the 2007 AAPA survey, 68% of the ports responding indicated that they have such a plan; 61% indicated that they advise tenants periodically on stormwater compliance responsibilities.

Restoration of Aquatic Habitat

Ports often restore coastal habitat as mitigation for development activities and in broader stewardship efforts.

Restoring Fish Habitat

Most of the east side of Puget Sound is hardened with riprap and bulkheads. Restoration of more natural shoreline habitats is critical to the recovery of Puget Sound salmon. In part to mitigate the impacts of a new pier, the Port of Everett, WA, used a new method for pebble/sand beach construction to restore 1,100 feet of shoreline habitat in front of a rock bulkhead supporting a BNSF railroad line. Biological monitoring has already shown a high level of activity by juvenile salmon and forage fish along the restored shore.[35]

Invasive Species

Ships take on or discharge ballast water to accommodate changes to their displacement and trim as they load or unload cargo or take on or consume fuel.[36] As vessels transit the globe, they collect and discharge water many miles apart, and in the process can introduce nonindigenous species. These species are considered

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"invasive" if they are capable of exploiting their new environment and causing economic or environmental harm. Ships discharge an estimated 80 million tons of ballast water into U.S. waters each year.[37]

To combat the spread of invasive species, ships are required to take steps such as exchanging ballast water while at sea. However, management methods still need to be improved. EPA and AAPA are working with the U.S. Coast Guard, IMO, and others to promote effective policies and technologies for ballast water management and treatment. For example, the Duluth Seaway Port Authority, MN, hosts the world's first freshwater test facility for ballast water treatment technology. The facility, completed in June 2007, is part of the Great Ships Initiative, a cooperative research effort to which nine U.S. and Canadian ports have provided monetary or in-kind support.[38]

Waste Generation and Management

Dredged Material

Because of the natural process of sedimentation, periodic dredging of channels and shipping berths is necessary to ensure that vessels can continue to reach ports. Existing channels and berths must also be deepened and widened for U.S. ports to accommodate the largest container ships coming into use. Few U.S. ports have the channel depth of up to 55 feet that these vessels require.[39]

Although the U.S. Army Corps of Engineers is responsible for dredging navigation channels, ports and their tenants dredge 100 million cubic yards annually from vessel berths and private terminals.[40] Ports must dispose properly of both clean and contaminated dredge material, and are increasingly seeking beneficial reuses of this material.[41]

Beneficially Using Dredged Material

The Port of Fourchon, LA, is using dredged material to rebuild a natural forest ridge reduced by coastal erosion. Such forest ridges serve as buffers between the Gulf of Mexico and the coastal marsh habitats for fish, shellfish, and other wildlife. Working with volunteers and several private and governmental entities, the port has created 60 acres of forest habitat and 60 acres of salt marsh.[42]

Brownfields

Although ports will be able to accommodate some of the expected increase in trade volume by improving the efficiency of current operations, they sometimes need to build new facilities. Many ports seeking to expand existing facilities have revitalized nearby "brownfields," which are unused or underused industrial sites. In doing so, the ports must first address any environmental contamination. For example, the Port Authority of New York and New Jersey is remediating and developing a contaminated site on Staten Island, NY, in connection with the intermodal rail facility supporting the New York Container Terminal. Fifteen of the 38 ports that responded to AAPA's 2007 survey had participated in brownfields redevelopment in the past 5 years, contributing to redevelopment of more than 3,200 acres of brownfields.[43]

Disposal and Recycling

Ports handle a variety of materials and wastes, both generated onsite and from vessels. Since inception in 2005, the Port of Corpus Christi Authority, TX, recycling program has recycled 327,055 lbs. of materials, including 96,470 lbs. in 2007. The program includes recycling paper, plastic, cardboard, metal, batteries, tires, oil, oil and fuel filters, antifreeze, and capacitors. Cruise ships return to port with recyclable materials such as metal cans, glass, and batteries. They also offload hazardous wastes while at dock, such as waste generated during photo processing, dry cleaning, and ship maintenance. There are no estimates of the total volumes of solid and hazardous wastes brought into U.S. ports by cruise ships, although EPA is developing a "Cruise Ship Discharge Assessment Report" to address solid and hazardous waste.[44]

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Hazardous Waste Management

Port facilities generate various hazardous wastes. Vessel refurbishing and maintenance operations generate spent solvents and caustics, and paints and paint sludge. Examples of other marine facility wastes that may be hazardous include vehicle maintenance fluids, near-empty paint cans, and paint-stripping residue.[45] In AAPA's 2007 survey, 17 of 38 ports (45% of respondents) indicated that they generate enough hazardous waste to require tracking and reporting.[46]

Additional Environmental Management Activities

Environmental Management Systems

An environmental management system (EMS) is a set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency. The Ports EMS Assistance Project, which EPA helped AAPA launch, has guided 13 ports in developing EMSs over 4 years.[47] The Ports of Boston, MA, Corpus Christi and Houston, TX, and Los Angeles, CA, have each received third-party ISO 14001 certification, and other ports are working toward this recognition.[48] In AAPA's survey, the percentage of ports with an EMS in place or under development increased from 29% in 2005 to 47% in 2007. The number of ports publishing an annual environmental review or report also increased from 4% in 2005 to 29% in 2007.[49] AAPA also assisted EPA in development of *An EMS Primer for Ports: Advancing Port Sustainability*.[50]

Voluntary Sustainability Partnership

Green Marine is a new, voluntary sustainability initiative designed to help the marine transportation industry between the Gulf of St. Lawrence and the Great Lakes minimize its environmental footprint without compromising economic viability. The initiative, officially announced in October 2007, includes U.S. and Canadian carriers and ports. Priority issue areas include air emissions, discharges to water, and invasive species. The partnership has published an action plan and will enlist a third party to evaluate and report on the conformance of the program's corporate members.[51]

Sustainability

Some ports are building on the systems-based management approach of EMSs to address broader aspects of sustainability. AAPA is working to develop a sustainability framework. AAPA members approved a sustainability resolution and principles in October 2007. The resolution states, "Sustainability involves the simultaneous pursuit of economic prosperity, environmental quality and social responsibility," and AAPA "embraces the concept of sustainability as a standard business practice for ports and the Association."[52]

Community Involvement

Because of their size, location, and high profile, ports increasingly recognize the importance of effectively communicating with surrounding communities about the environmental aspects of port operations.

Environmental Outreach

The Port of Portland, OR, has created a position within its Community Affairs Department specifically for environmental outreach and communication. The port also provided its staff with "Community Integration Guidelines," an extensive menu of outreach approaches and tools to use when engaging the public. Several of these tools have been used effectively during the decisionmaking process for cleanup of contaminated sediment at the port's Terminal 4. For example, the port has hosted five open houses corresponding to different phases of the project, and it arranged for stakeholders to visit two confined disposal facilities in the Puget Sound area. The port's outreach efforts have reached more than 300 stakeholders and identified specific areas of citizen concern that the port might otherwise have overlooked.[53]

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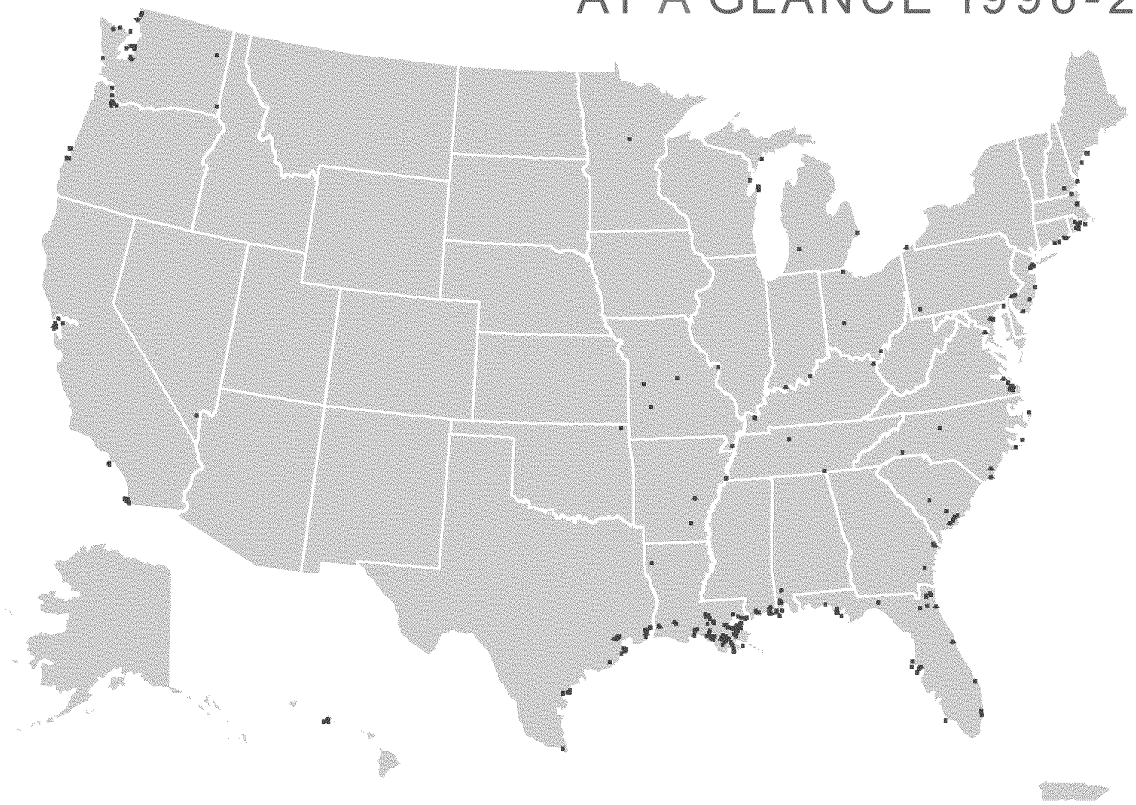
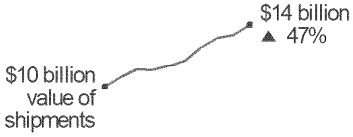
AT A GLANCE 1996-2005[1]



2005: 346 facilities



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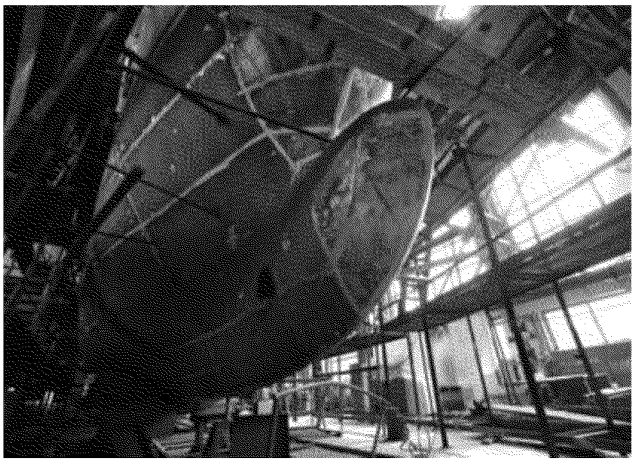

Latest Environmental Statistics[2]

Emissions of Criteria Air Pollutants: 5,900 tons

Releases of Chemicals Reported to TRI: 2 million lbs.

- airemissions: 1.8 million lbs.
- Water Discharges: 19,000 lbs.
- Waste Disposals: 226,000 lbs.
- *Recycling, Energy Recovery, or Treatment: 5.1 million lbs.*

Hazardous Waste Generated: 7,000 tons

Hazardous Waste Managed: 6,000 tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Profile

Facilities in the Shipbuilding & Ship Repair sector build, repair, or alter ships, barges, and other large vessels for military and commercial clients. Most facilities that build ships can also repair them, but some smaller shipyards only perform ship repair work.

Shipyards typically include drydocks, shipbuilding positions, berthing positions, piers, workshops, and warehouses.

Most domestic shipbuilders make and repair ships for the U.S. Navy, U.S. Coast Guard, and other government agencies. The sector has less than a 1% share of the world's market for commercial vessels of more than 100 gross tons.[3]

Energy Use

According to the U.S. Department of Energy (DOE), energy use for the transportation equipment manufacturing sector, which includes shipbuilding activities as well as motor vehicle manufacturing, totaled 424 trillion Btu in 2002. There are not sufficient data to determine the proportion of energy used by the Shipbuilding & Ship Repair sector alone.[4]

Shipbuilding and ship repair processes that use the most energy are welding (most often electric arc welding), forging, abrasive blasting, and application of marine coatings. Electricity purchases represented 75% to 80% of the sector's expenditures for energy in 2004.[5] The sector's remaining energy expenditures were for fossil fuels such as natural gas, coal, and petroleum. Between 1998 and 2004, shipbuilders use of electricity per dollar value of shipments (VOS) fell 10%.[6]

There are opportunities for shipbuilders to reduce one energy source in favor of another with fewer emissions or greater efficiency. One option is for facilities to replace equipment that consumes fossil fuels with electric-powered equipment. For example, in the forging process, facilities can replace gas-fired heating with electric induction heating, which has lower operational costs and requires less energy. The environmental benefits of switching equipment to electric power will depend in part on the fuels used by the electricity provider.

Air Emissions

Air emissions in the sector include criteria air pollutants (CAPs), greenhouse gases (GHGs), and a number of chemicals reported to EPA's Toxics Release Inventory (TRI). In general, the "toxic chemicals" tracked by TRI are found in the raw materials and fuels used, and can also be generated by their use. Major sources of air emissions for this sector are welding, abrasive blasting, and application

Biodiesel Use

In 2006, Atlantic Marine Alabama, LLC, a shipbuilder headquartered in Mobile, AL, measured the performance of two forklifts powered by a biodiesel blend (B20) against the performance of two forklifts fueled with regular diesel. During the four-month trial, the biodiesel-powered forklifts used nearly 9% less fuel per hour with no difference in performance or the visibility of emissions between the two sets of forklifts. In addition, over the course of the trial, the B20 cost an average of 50 cents less per gallon than standard diesel. Based on these results, Atlantic Marine plans to convert all of its diesel-powered yard equipment to B20 within the next five years.[7]

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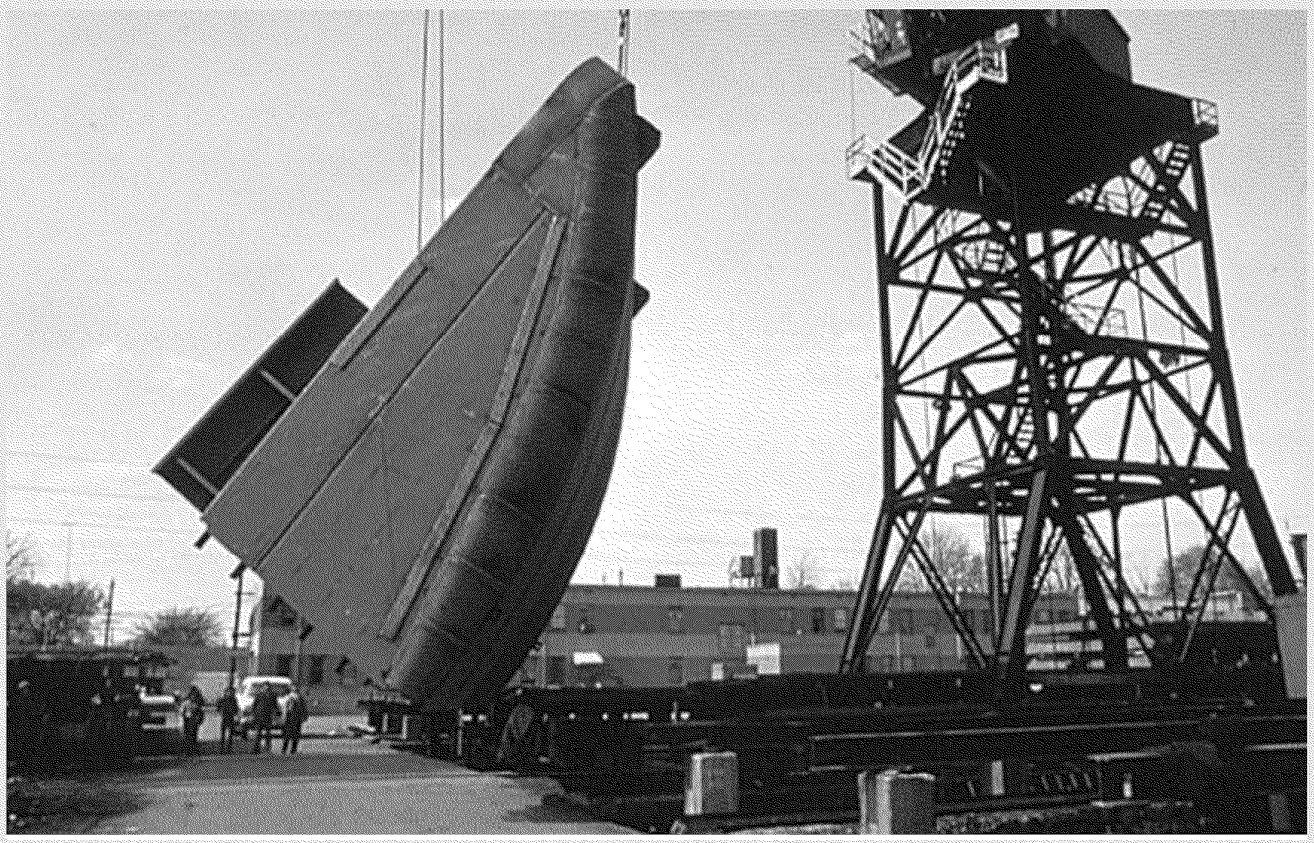

of marine coatings. CAPs and GHGs are also generated as combustion byproducts from onsite combustion of fuels.

Air Emissions Reported to TRI

In 2005, 54 facilities reported 1.8 million absolute lbs. of air emissions of TRI chemicals, as shown in Figure 1a. TRI-reported air emissions decreased by 44% in absolute pounds from 1996 to 2005. When normalized by the sector's increasing VOS, air emissions decreased 54% from 1996 to 2005.[8]

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 1c. When normalized by the sector's VOS, the sector's Toxicity Scores fluctuated between 1996 and 2005, declining overall by 34%. Fluctuations in the Toxicity Scores were driven by changes in the quantities of manganese and chromium emitted to air over the years, as discussed below.

The TRI list of toxic chemicals includes all but six of the hazardous air pollutants (HAPs) regulated under the Clean Air Act. In 2005, 47 Shipbuilding & Ship Repair facilities reported about 800,000 lbs. of HAPs emitted to air, representing 43% of the total pounds of air emissions that the sector reported to TRI for 2005, and 76% of the Toxicity Score.

As with overall TRI air emissions, manganese and chromium, both classified as HAPs, drove the sector's Toxicity Scores for HAPs.[9] Welding activities and the use of certain abrasives such as coal and smelter slags can result in air emissions of these metals. In addition, in 1999 and 2000, a major source of chromium air emissions from repair shipyards was related to a primer called Ameron 385. The U.S. Navy required the use of this primer on Military Sealift Command ships. In 2001, the primer was reformulated to remove chromium, resulting in a significant drop in the quantity of chromium emitted by the sector.[10]

Table 1 presents the top TRI-reported chemicals emitted to air by the Shipbuilding & Ship Repair sector based on three indicators. Each indicator provides data that environmental

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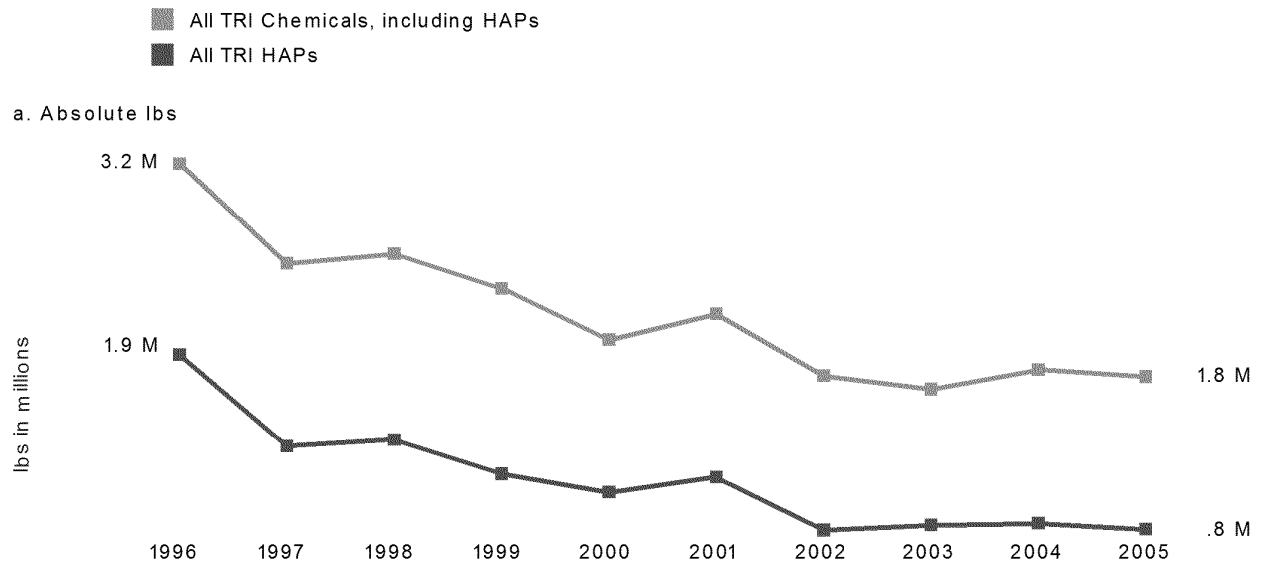
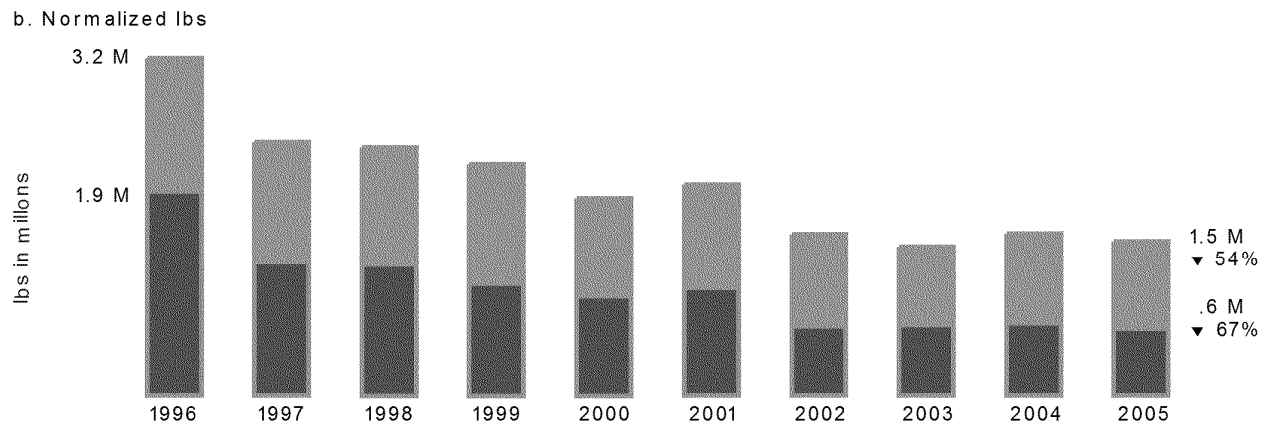
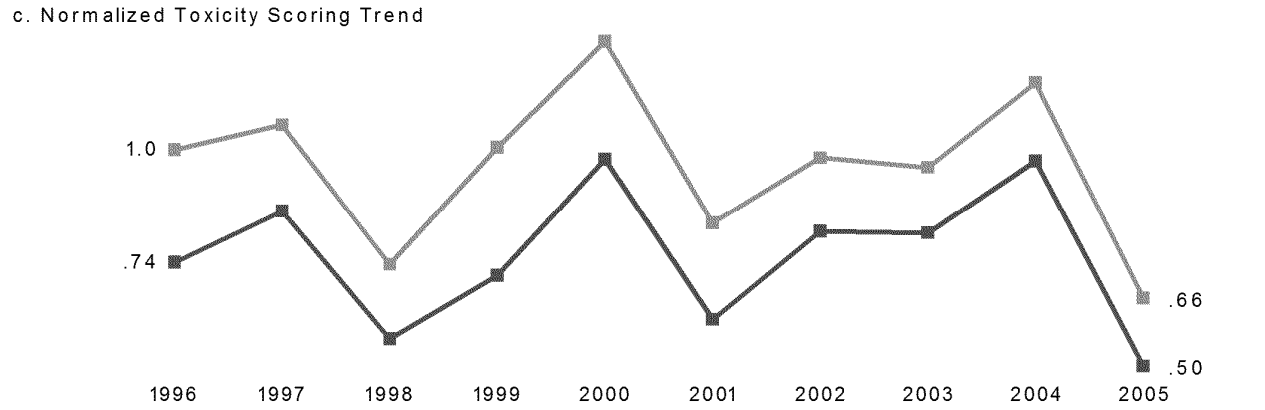
Figure 1

Air Emissions Reported to TRI 1996–2005







Note:
Normalized by annual value of shipments.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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Table 1

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage of Toxicity Score	Number of Facilities Reporting[2]
1,2,4-Trimethylbenzene	185,100[3]	9%	8
Chromium	1,397	19%[4]	17
Ethyl Benzene[5]	91,900	<1%	7
Manganese	8,077	45%	19
N-Butyl Alcohol	606,700	<1%	21
Nickel	1,798	10%	17
Propylene	106,900	<1%	11
Sulfuric Acid	30,400	8%	1
Xylene	529,700	1%	28
Percentage of Sector Total	**87%**[6]	**92%**[7]	**91%**[8]

Notes:
1. Total sector air releases: 1.8 million lbs.
2. 54 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
5. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
6. Chemicals in this list represent 87% of the sector's air emissions.
7. Chemicals in this list represent 92% of the sector's Toxicity Score.
8. 91% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. N-butyl alcohol and xylene were the highest-ranking chemicals based on the pounds of each chemical emitted to air in 2005.
2) Percentage of Toxicity Score. The top chemicals based on Toxicity Scores were dominated by metals, as described above.[11]
3) Number of Facilities Reporting. Xylene and n-butyl alcohol were also the most frequently reported chemicals, with most of the TRI-filers in the sector reporting air emissions of at least one of these chemicals.

Criteria Air Pollutants

Table 2 shows CAP and volatile organic compound (VOC) emissions for 81 facilities in the sector in 2002.[12]

To prepare vessel surfaces for coatings, shipyards typically apply a dry abrasive material at high velocity. This blasting process, which is usually performed outside due to the size of the ships, generates particulate matter (PM) emissions from both the break-up of the abrasive material and the removal of the existing coatings. Common blasting abrasives include coal slag, copper slag, garnet, and other metallic grit and shot.[13] To reduce PM emissions, shipyards

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shrink-wrap vessels or use shrouds to reduce wind speed in the blasting area. In addition, some shipyards use alternative technology such as ultra-high pressure water blasting to reduce PM emissions.

Table 2

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	1,000
NO_X	900
PM_{10}	800
$PM_{2.5}$	400
CO	200
VOCs	3,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

The coatings applied to a vessel's surface typically contain VOCs that are emitted to the environment during application. To reduce VOC emissions, shipyards have been working with coatings manufacturers to reformulate coatings to reduce the content of VOCs and other air toxics. In addition, shipyards are using new application technologies that reduce overspray and waste, resulting in less paint used overall.

Greenhouse Gases

Shipbuilding & Ship Repair GHG emissions are primarily attributable to fossil fuel combustion for non-road equipment. Other likely GHG sources include refrigerants, welding gases, thermal oxidizers to destroy VOCs, and CO_2-based fire extinguishers. However, there are currently no data available on the quantity of such emissions. The generation of electricity purchased by sector facilities also emits GHGs.

To reduce their GHG footprint, facilities in the sector could improve on-site energy efficiency and could purchase electricity produced without combustion of fossil fuels. The American Shipbuilding Association and the Shipbuilders Council of America are working with EPA to develop a tool to measure GHG emissions, which should provide better data on the sector's GHG emissions in the future.

Water Use and Discharges

Shipbuilding & Ship Repair firms typically obtain water from public water systems, and sometimes pull water directly out of the rivers for non-contact cooling. There are currently no aggregate data available on the quantity of the sector's water use.

In 2005, 16 facilities reported water discharges of about 19,000 lbs. of TRI chemicals. When normalized by VOS, water discharges declined by 30% from 1996 to 2005.[14] The sector discharges water to Publicly Owned Treatment Works and, in some cases, directly to water bodies. Stormwater run-off is also an important issue for the sector.

Proper management of stormwater is a concern for the sector because shipyards are adjacent to major water bodies and include outdoor operations where materials and equipment can be exposed to precipitation. Chemicals discharged in stormwater primarily consist of blasting and painting materials. Of particular interest are discharges of copper, zinc, and lead from anti-foulant coatings, which retard the growth of aquatic organisms.

Best Management Practices (BMPs) for Cleaning Drydocks

Drydocks, which are typical features of shipyards, are work areas that can be flooded to allow a vessel to enter or leave. The industrial activities that take place on drydocks (e.g., abrasive blasting, painting) can generate significant concentrations of pollutants such as heavy metals, oil and paint residues, spent abrasive, and other debris. Thorough cleaning of the drydock prior to its submergence ensures that these pollutants are not discharged to receiving waters.

BAE Systems San Diego, CA, has implemented BMPs to ensure that its dry docks are clean before they are submerged, thus preventing particles generated during ship construction and maintenance from being discharged into nearby waters.

Before clean-up activities begin, the company inspects the drydock and determines clean-up details, such as number and size of hoses for washing, number of pumps to collect washwater, and number and capacity of tanks to hold washwater. Some notable practices utilized by BAE Systems during drydock cleaning include:

- Ensuring proper trim of the drydock,
- Installing splash boards to prevent washwater from spilling into the bay when washing near the edge of the dock,
- Monitoring the trough and sump to prevent overflows,
- Ensuring sufficient holding capacity for washwater (including planning for rain),
- Thoroughly inspecting the drydock after cleaning and before submergence, and
- Documenting all of the above actions.[15]

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Shipyards' stormwater runoff is typically regulated under a multi-sector general industrial stormwater permit. However, some states require facilities to have individual National Pollutant Discharge Elimination System permits for stormwater and to meet discharge limits. Permit requirements vary from state to state and can range from requiring a stormwater management plan, to using BMPs, to requiring zero discharges.

Waste Generation and Management

Wastes in the sector can be generated from process-related functions or from other activities such as operation of pollution control devices or remediation of past contamination. Spent abrasives and oil or oily water are typically the largest volumes of waste generated in shipyards.

Hazardous Waste Management

In 2005, 96 facilities in the sector reported to EPA's *National Biennial RCRA Hazardous Waste Report* (BR) generating about 7,000 tons of hazardous waste. Waste paint and spent solvents, although produced less than spent abrasive and oily waste, generally constitute the sector's largest hazardous waste stream. In 2005, painting and coating processes accounted for 42% of the total hazardous waste generated (about 3,000 tons).[16]

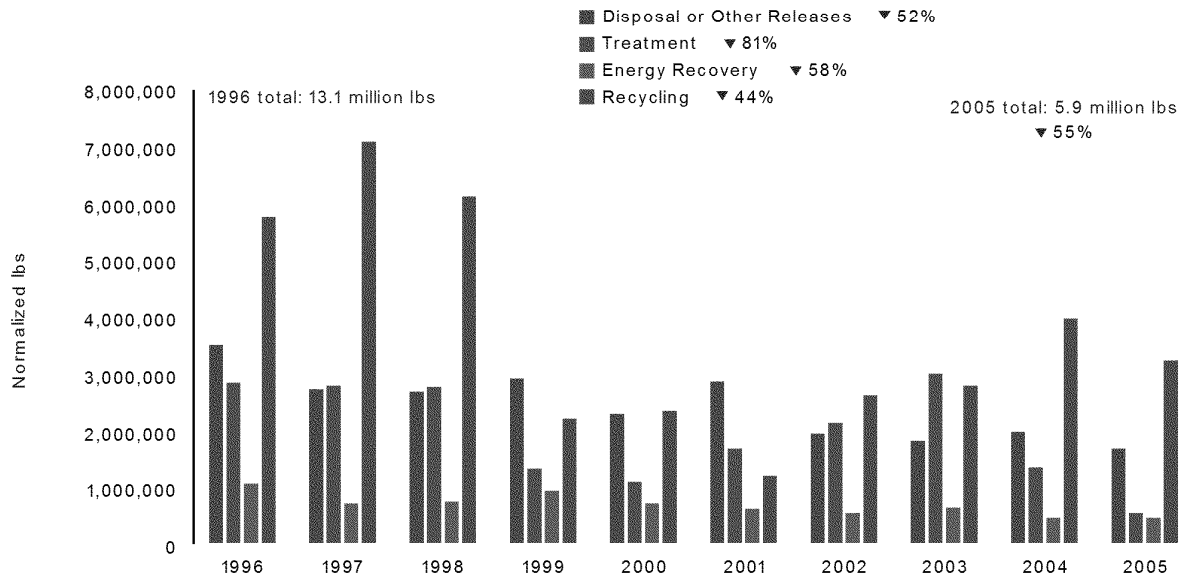
Improvements in process management of coating application and equipment cleaning have resulted in reductions in the amount of painting and coating waste. For instance, in-line plural component mixers prepare coatings as they are required. This prevents the generation of paint waste from mixing more paint than is required to complete a job. Additionally, paint waste is now used in fuel blending, whereas previously it would have been solidified for land disposal. Shipyards are also reclaiming and reusing solvents used to clean spray paint equipment.

The sector managed its hazardous waste in 2005 through disposal, treatment, and reclamation and recovery, in roughly equal proportions. The sector reported managing 6,000 tons of hazardous waste. The primary method of reclamation and recovery used by the sector was fuel blending.

Waste Management Reported to TRI

In 2005, the sector managed 7.2 million absolute lbs. of TRI-reported chemicals. When normalized by VOS, this was 55% less than in 1996. Figure 2 shows the trends in waste management by the sector. In 2005, 29% of the TRI-reported waste was disposed to land or released, 9%

Figure 2
TRI Waste Management 1996–2005



Notes:
1. Normalized by annual value of shipments.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Department of Commerce

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was treated, 8% was used for energy recovery, and 55% was recycled. Of the waste disposed or released, 11% was disposed. As shown in Table 3, copper and zinc accounted more than half of the total disposals in 2005; copper and nickel were the most frequently reported chemicals for this sector during the same year.[17]

The quantity of waste that shipyards disposed, as reported to TRI, decreased from about 251,000 lbs. in 1996 to about 226,000 lbs. in 2005. The chemicals were disposed to land or transferred to offsite locations for disposal.

Table 3

Top TRI Disposals 2005

Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Chromium	12,900[3]	13
Copper	69,100	14
Lead	**8,900**	**9**
Manganese	**7,300**	**9**
Nickel	**10,400**	**14**
Phenol	**21,000**	**1**
Xylene	**13,600**	**3**
Zinc	**46,100**	**7**
Percentage of Sector Total	**84%**[4]	**54%**[5]

Notes:
1. Total sector disposals.: 226,000 lbs.
2. 54 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 84% of the sector's disposals.
5. 54% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

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Data Sources, Methodologies, and Considerations

Important public sources of data used in this report—discussed in the Data Guide—include the U.S. Department of Energy's (DOE) Manufacturing Energy Consumption Survey (MECS), EPA's Toxics Release Inventory (TRI) and relative Toxicity Scores from EPA's Risk-Screening Environmental Indicators (RSEI) model, EPA's National Emissions Inventory (NEI), EPA's *National Biennial RCRA Hazardous Waste Report* (BR), production data from the U.S. Geological Survey's (USGS) Mineral Commodity Summaries, and economic data from U.S. Department of Commerce (U.S. Census Bureau and Bureau of Economic Analysis).

Private sources of data are sector-specific; for example, cement kiln dust surveys for Cement Manufacturing, and information from the American Forest & Paper Association's Environmental, Health, and Safety Verification Program for Forest Products. These data sources are referenced in the sector chapter endnotes.

Normalization

The best available data for each sector are used to normalize the sectors' pollutant releases and management over time as described in the Data Guide.

As an example, the sector air emissions figures show air emissions from 1996 through 2005. In sections (b) and (c) of the figure showing trends in air emissions, data were normalized, often using the annual value of shipments (VOS), adjusted for inflation using 1996 dollars as the base year, or productivity data adjusted against the 1996 starting quantity. The formula for this adjustment is:

$$\text{Measures for Year 'A'} \times \frac{\text{1996 Normalized Data (\$ or production value)}}{\text{Year 'A' Normalizing Data (\$ or production value)}}$$

Dollars, when used for normalizing, are adjusted for inflation using U.S. Department of Commerce's Gross Domestic Product data, available at: **http://bea.gov/national/xls/gdplev.xls**.

For most sectors, value of shipment data are compiled based on the primary Standard Industrial Classification (SIC) (pre-1998) and North American Industry Classification System (NAICS) codes (1998 forward). For all other sectors, data are compiled directly from the source listed in the table in the Data Guide.

Production Data

The "At-a-Glance" section of each sector chapter presents a measure of the sector's output. As with normalizing, production data (e.g., tons of product produced annually by the sector) were the preferred metric for depicting the output of the sector. When production data were not available, alternate metrics were identified, as noted in the sector chapter endnotes.

Employment and Facility Counts

Data Processing

The County Business Patterns (CBP) data have been tabulated on a NAICS basis since 1998. Data for each sector are compiled for each metric based on the NAICS codes defining the sector. Data are available at: **http://www.census.gov/epcd/cbp/view/cbpview.html**.

Mapping

For most NAICS/SIC-defined sectors, the maps present facilities in the sector that are in one of EPA's data systems. EPA's data systems provide location information that can be used for mapping, although smaller facilities without federal permits or IDs are under-represented. For list-defined sectors (Cement Manufacturing and Iron & Steel), the maps present those facilities comprising the sector. For several sectors that are not well represented in EPA data systems, alternative data sources were used for developing the sector maps. These sectors are Construction, Colleges & Universities, and Ports. For Construction, U.S. Census Bureau information on the number of construction establishments per state was mapped. For Colleges & Universities, the map represents the institutions listed on **www.collegeboard.com**, maintained by the not-for-profit College Board association. For Ports, the map shows the U.S. ports listed on the American Association of Port Authorities website, available at: **http://www.aapa-ports.org**.

Energy Use

This report uses energy consumption data from the 2002 MECS published in 2005. DOE's Energy Information Administration (EIA) conducts the survey and defines the manufacturing sector as all manufacturing establishments (NAICS codes 31-33) in the 50 states and the District of Columbia.

Considerations

Detail of data

The Sector Strategies Program defines sectors based on 3-, 4-, 5-, and/or 6-digit NAICS code combinations. MECS energy consumption estimates for most manufacturing industries are only available at the 3-digit NAICS code level, although data for some select manufacturing sectors are available at the 6-digit NAICS code level. For the sectors in

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this report, 2002 data at the 6-digit level are available for the Cement Manufacturing, Forest Products, Iron & Steel, and Metal Casting sectors.

historical and current energy consumption data

The 2002 MECS sample size was approximately 15,500 establishments drawn from a sample frame representing 97-98% of the manufacturing payroll, which is approximately 60% of the establishments of the manufacturing sector. MECS data provide energy consumption by fuel type, including electricity, natural gas, residual fuel oil, distillate fuel oil, liquid petroleum gas, coal, coke, and other. The composition of the "other" fuels category varies from sector to sector. More detail is provided in individual sector chapters.

Although the 2002 MECS provides the most recent publicly available data on sector energy consumption, energy prices have undergone major changes in the last 6 years; the effects of such changes on sector energy consumption since 2002 are not reflected in the 2002 MECS data used in this analysis.

energy consumption projections

For an overview of expected future trends for industrial energy consumption and associated carbon dioxide (CO_2) emissions, as well as energy projections for specific sectors, we referenced EIA's 2006 Annual Energy Outlook (AEO), EIA's most recent annual forecast of energy demand, supply, and prices through 2030.[1]

energy efficiency and clean energy opportunities for manufacturing industries

We consulted industry-specific research conducted by DOE and research institutions such as the Ernest Orlando Lawrence Berkeley National Laboratory, as well as a number of online and hard-copy materials produced by industry trade associations that describe technological and process opportunities for increasing energy efficiency.

industry commitments to environmental improvement with respect to energy use

We reviewed public-private partnership programs such as Climate VISION, which is supported by DOE, EPA, and the U.S. Departments of Transportation and Agriculture, and DOE's Industrial Technologies Program, for information on emerging industrial energy-efficient and clean energy opportunities for energy-intensive sectors, including developing technologies. Note that individual companies/facilities within each sector may also participate in other voluntary programs (e.g., ENERGY STAR, Performance Track, Climate Leaders, etc.).

Small businesses not included

MECS does not include small establishments, including those with fewer than 5 employees or those with 5 to 20 employees with annual payrolls and shipments below certain minimums.

Data Processing

This report uses MECS data on energy consumed for fuel-related purposes only (presented in MECS Table 3.2). MECS data are also available in terms of energy consumed for all purposes (or "first use," which includes fuels used as feedstocks); in terms of energy consumed for nonfuel purposes (primarily feedstocks); and in terms of consumption of fuels. While some industries use fuels as feedstocks—raw material inputs in the manufacturing process—feedstock-related fuel use may or may not contribute to criteria air pollutant (CAP) and greenhouse gas (GHG) emissions. As feedstock fuel use does not represent an opportunity for reducing the environmental impacts associated with energy consumption, the energy use sections of this report focuses on energy inputs for fuel use only. Units of measure are maintained in British thermal units (Btu). Data and documentation of EIA's data processing methodology used to develop sector energy consumption estimates are available online at: **http://www.eia.doe.gov/emeu/mecs**.

Air Emissions Reported to TRI

TRI was established under the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA) and expanded by the Pollution Prevention Act of 1990. Section 313 of EPCRA provides three criteria defining the scope of facility owners/operators that report to EPA's TRI program:

1. The facility has 10 or more full-time employees, or the equivalent of 20,000 employee hours per year.
2. The facility is included in a list of applicable NAICS codes. The NAICS codes correspond to the following SIC codes: SIC 10 (except 1011, 1081, and 1094); 12 (except 1241); 20-39; 4911 (limited to facilities that combust coal and/or oil for the purpose of generating electricity for distribution in commerce); 4931 (limited to facilities that combust coal and/or oil for the purpose of generating electricity for distribution in commerce); 4939 (limited to facilities that combust coal and/or oil for the purpose of generating electricity for distribution in commerce); 4953 (limited to facilities regulated under the Resource Conservation and Recovery Act (RCRA) Subtitle C, 42 U.S.C. section 6921 et seq.); 5169; 5171; and 7389 (limited to facilities primarily engaged insolvent recovery services on a contract or fee basis). Executive Order 13423 extended these reporting requirements to federal facilities, regardless of their SIC or NAICS code.
3. The facility manufactures (defined to include importing), processes, or otherwise uses any of the toxic chemicals listed on the EPCRA section 313 in amounts greater than the threshold quantities established in 40 Code of Federal Regulations (CFR) 372.25 and 372.28 in the course of a calendar year.

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Facilities described above must report their releases and waste management quantities for a chemical included on the TRI list of toxic chemicals if they manufacture or process that chemical in quantities exceeding 25,000 lbs. within a calendar year, or otherwise use that chemical in quantities that exceed 10,000 lbs. per year in a calendar year. Reporting thresholds for TRI-listed chemicals designated by EPA as persistent bioaccumulative toxic (PBT) chemicals, such as lead and mercury, are lower.

In 2005, more than 23,000 facilities reported to EPA's TRI program. These facilities reported 4.4 billion lbs. of onsite and offsite disposal or other releases, which included 1.5 billion lbs. of air emissions, 242 million lbs. of water discharges, and 2.7 billion pounds of disposals. They also reported 25.1 billion lbs. of production-related waste managed.

Considerations

comprises a list of reportable chemicals

Facilities in the TRI-reporting industry sectors must file if they exceed the reporting thresholds for any of the 600+ chemicals.

only captures facilities above threshold

Note that only those facilities that exceed the TRI reporting thresholds are required to report to TRI; thus, TRI-reported trends may not be representative of the sector as a whole.

Small businesses not included

TRI excludes smaller facilities, that is, those with fewer than 10 employees.

Multimedia coverage

TRI reporting covers releases and other disposal to all environmental media (air, water, and land).

changes in tri requirements

Reporting thresholds for PBTs were lowered in reporting year 2000 (in 2001 for lead and lead compounds) to 10 lbs. or 100 lbs., depending on the chemical. These lower thresholds resulted in more facilities reporting, and caused significant increases in the quantities of some of the specific PBTs reported as released (including disposed) or managed as waste, such as lead and polycyclic aromatic compounds. However, given that the thresholds are so much lower than thresholds for non-PBTs, the increased quantities for this small group of chemicals usually did not influence overall sector trends for air emissions or waste management. The lower reporting threshold could also influence trends in hazardous air pollutants (HAPs), as many of the PBTs are also HAPs. The PBTs that are also HAPs are: chlordane, heptachlor, hexachlorobenzene, lead and lead compounds, mercury and mercury compounds, methoxychlor, polychlorinated biphenyls, polycyclic aromatic compounds, toxaphene, and trifluralin. Other changes to the TRI program, such as the addition of non-manufacturing industries in 1998, are not expected to influence trends for the sectors presented in this report.

Data accuracy

Facility owners/operators are responsible for TRI reporting using their best available information. The data facilities submit on releases and waste management quantities are calculated using one of the following methods: monitoring or measurement; mass balance calculations; emission factors; or engineering estimates. There is no independent verification of the accuracy of the submissions. The increasing use of direct electronic filing of TRI reports may reduce the potential for data processing errors. In 2005, 95% of the facilities submitting reports to TRI used electronic reporting.

changes in best available information

Facilities are required to complete their TRI forms using their best available information. Industry representatives have pointed out that estimates of releases might change over time as more information becomes available. For example, while conducting measurements required by another regulation, such as emissions testing required by a National Emission Standard for Hazardous Air Pollutants, a facility may find a TRI-reportable chemical in its releases that it was not aware of previously. As facilities learn of the existence of various chemicals, they are then required to report those releases to TRI. This situation would result in an increased level of reported releases that is not necessarily accompanied by an increase in actual emissions.

Some sectors do not report

Facilities involved in oil and gas exploration and transportation, for example, are exempt from both TRI and BR. The publicly and privately owned marine facilities discussed in the Ports chapter also do not report to TRI, although their tenants may.

Data Processing

TRI data for reporting years 1996-2005 are sourced from the 2005 Public Data Release (PDR) for all but two sectors; data for Paint & Coatings and Shipbuilding & Ship Repair are drawn from the 2006 PDR. "Frozen" data are used to ensure reproducibility and to support later revisions of the analysis.

Trend data are normalized by changes in VOS or production, with 1996 as the baseline year.

For most sectors, data are compiled based on the most current primary SIC code reported on the TRI Form R. For example, if a facility reported differing primary SIC codes in reporting year 2004 and 2005, the primary SIC code from the most current available year (in this case 2005) was used. Similarly, if a facility did not report to TRI in 2005, data from the most recent year of available primary SIC code data were used. For the Cement Manufacturing and Iron & Steel sectors, and for the specialty-batch chemicals subsector, the sector TRI data are extracted based on predetermined facility lists. The count of the number of facilities reporting to TRI is a total of the number of unique

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TRI identification numbers (IDs) in the sector. Each facility, as defined by the TRI program, should have one TRI ID.

For air emissions, TRI data elements for this report include:

- **Air Releases**—stack and fugitive emissions as reported in sections 5.1 and 5.2 of TRI Form R, respectively.
- **HAPs**—TRI includes all but six of the chemicals designated as HAPs, also known as "air toxics," by the Clean Air Act (CAA) Section 112b. HAPs are air pollutants that pose a direct threat to human health. TRI, rather than NEI, was used as the source for sector-level HAPs data; see discussion of "Criteria Air Pollutants" below. TRI was chosen as the data source primarily because TRI allows for an analysis of annual trends over a 10-year period, whereas NEI HAP data are available for 1999 and 2002 only. HAPs emissions include stack and fugitive emissions of the subset of TRI chemicals that are designated as HAPs, as reported in sections 5.1 and 5.2 of TRI Form R. The TRI HAP analysis in this report excludes three additional HAPs (4,4'-methylenediphenyl diisocyanate, hexamethylene-1,6-diisocyanate, and 2,3,7,8-tetrachlorodibenzo-p-dioxin), because these chemicals are reported to TRI only as part of larger chemical categories, and quantities of the individual chemicals released are not included in TRI.

For releases and management, data are presented in pounds (lbs). For toxicity-weighted results, data are presented as a ratio using 1996 as the baseline year.

Beginning with the 2006 reporting year, facilities reporting to TRI are required to use NAICS codes in place of the SIC codes previously used on TRI reporting forms. Facilities that report to TRI are required to use 2002 NAICS codes on reporting Form R and the Form A Certification Statement.[2]

Toxicity of Air Emissions

Aspects of RSEI influence the use of these modeled TRI data for EPA's Sector Strategies Program. Extensive documentation is available on the development of RSEI. Some of this information is summarized below. For more details, refer to EPA's Risk-Screening Environmental Indicators (RSEI) Methodology, Version 2.1.5, October 2007, available at: **http://www.epa.gov/opptintr/rsei/pubs/method_oct2007.pdf**.

Considerations

uses highest relative toxicity weight for chemical categories

Because information on the chemical form released is not reported to TRI, chemicals within a chemical category (e.g., metal compounds, diisocyanates) are assumed to be released in the chemical form associated with the highest relative toxicity weight. The form of a chemical compound can affect its toxicity. For example, hexavalent chromium has an oral relative toxicity weight of 170 and an inhalation relative toxicity weight of 86,000; whereas trivalent chromium has an oral and inhalation relative toxicity weight of 0.33. TRI reports filed for "chromium" do not specify the valence, so all reported pounds of chromium are more conservatively assigned the relative toxicity weight of hexavalent chromium. In cases where a facility is releasing the chemical in the lower toxicity form, RSEI would overestimate toxicity-weighted results.

comparing rSei results

The numeric RSEI output depicts the relative toxicity of TRI releases for comparative purposes and is meaningful only when compared to other values produced by RSEI.

excludes certain chemicals

There are 611 chemicals and chemical categories on the 2005 TRI Chemical List. Toxicity weights are available for 429 of these chemicals and chemical categories. Chemicals with relative toxicity weights account for more than 99% of the reported pounds for all on-site releases in 2005. If there is no relative toxicity weight available for a chemical, then the default Toxicity Score is zero. Examples of chemicals that do not have an assigned relative toxicity weight in RSEI include: dioxin and dioxin-like compounds, phenol, benzo(g,h,i)perylene, and tetrabromobisphenol-A.

currently excludes toxicity weights for chemicals disposed

An inhalation relative toxicity weight is used for fugitive and stack air releases. An oral relative toxicity weight can be used for direct water releases, but is not included in this report. Releases to land and other disposal are not modeled because necessary data on site-specific conditions are lacking.

acute human or environmental toxicity not addressed

RSEI addresses chronic human toxicity (cancer and non-cancer effects, e.g., developmental toxicity, reproductive toxicity, neurotoxicity, etc.) associated with long-term exposure but does not address concerns for either acute human toxicity or environmental toxicity.

results presented do not include a risk perspective

Toxicity weighting of a chemical is not the same as identifying the risk potentially posed by a release of the chemical to the environment. "Risk" in that context would rely on additional information, such as the fate and transport of the chemical in the environment after it is released, the pathway of human exposure, the amount of chemical to which human subjects are exposed, the duration of exposure, and the amount of the chemical that enters the human body following exposure. Although the RSEI model can provide a relative risk-related perspective for air releases, only the toxicity portion of the model was used in the analysis for this report. Risk-related factors were not considered. Readers interested in the risk perspective for a facility or sector can use the publicly available RSEI model to conduct this screening-level risk analysis.

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Data Processing

RSEI calculates toxicity-weighted results for each chemical by multiplying the quantity of chemical released to air by a chemical-specific toxicity weight. Results are then summed across chemicals to present overall sector-wide results. The toxicity weight is a relative value and is presented in this report relative to the sector's total 1996 toxicity-weighted results for all air emissions. Focusing on toxicity provides an alternative perspective to typical quantity-based environmental loadings and moves the discussion forward towards an impact-based assessment.

TRI documentation is available at: **http://www.epa.gov/tri**. RSEI model documentation is available at: **http://www.epa.gov/opptintr/rsei**.

Criteria Air Pollutants

EPA prepares the NEI based on input from numerous state, tribal, and local air pollution control agencies; industry-submitted data; data from other EPA databases; as well as emission estimates. State and local emissions inventories are submitted to EPA once every three years for most point sources contained in NEI. Through the 1999 NEI, EPA estimated emissions for any jurisdiction that did not submit an emissions inventory and where data were not available through industry submissions or other EPA databases. As a result of the Consolidated Emissions Reporting rule, NEI updates for 2002 and beyond are expected to include data uploads from all jurisdictions. The CAP and volatile organic compound (VOC) data presented in the sector chapters include emissions from point sources, and not emissions from area and mobile sources.

Considerations

Frequency of nei

NEI data are released triennially, which limits the number of data points for a time-series analyses. The report includes data only from 2002, because data from prior years are not comparable or present other data challenges.

nei haP data

In addition to CAP data, NEI also includes data on the CAA designated HAPs. This report presents HAP data from TRI rather than NEI, primarily because TRI allows for annual trend analyses. NEI, in contrast, is generated every three years. Currently, the 1990 and 1996 NEI databases are not recommended for use due to unusable format or data quality concerns.

Data Processing

Final v3 2002 NEI Point Source CAP data were obtained from EPA's Clearinghouse for Inventories & Emissions Factors (CHIEF). Data and documentation are available at: **http://www.epa.gov/ttn/chief/net/index.html**.

For most sectors, data are compiled based on the facilities' SIC or NAICS codes as included in the NEI. For the Cement Manufacturing and Iron & Steel sectors and for the specialty-batch chemicals subsector, NEI data are extracted based on a predetermined list of facilities.

For particulate matter (PM) emissions, this report presents PM-Primary, which includes both the filterable and condensable portions of PM emissions.

Greenhouse Gases

For information regarding GHGs, this report relies on the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (Inventory), and other public and private data sources. EPA prepares the Inventory to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC).[3]

The edition of the Inventory used in this report summarizes the latest information on U.S. anthropogenic GHG emission trends from 1990 through 2005. To ensure that it is comparable to those of other UNFCCC Parties, the estimates presented in the Inventory were calculated using methodologies consistent with those recommended by the Intergovernmental Panel on Climate Change (IPCC) in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), the IPCC *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (IPCC 2000), and the *IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (IPCC 2003).

Water Use and Discharges

There is no national database for water withdrawals. Such information, which DOE is starting to collect, is usually kept at the state level.[4]

Facilities discharging directly into the waters of the United States (e.g., "direct dischargers") are required to obtain a National Pollutant Discharge Elimination System (NPDES) permit. Data on discharges from NPDES-permitted facilities are entered into an EPA data system. EPA also develops the Effluent Data Statistics (EDS), which is a static file of annual loadings derived from the concentration and flow data submitted by NPDES facilities. The EDS file contains annual pollutant loadings (including for conventional pollutants) and flow at the permit level.

The Permit Compliance System (PCS) is the national database used to track compliance with NPDES, but it is being gradually phased out and replaced by a modernized system called the Integrated Compliance Information System (ICIS)-NPDES. Twenty-six states, territories, and tribes started using ICIS-NPDES in June 2006, and thus are not entering data into PCS.

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Data on pollutant discharges to sewage treatment plants are collected by local pretreatment programs, but these data are not systematically electronically transmitted to the states or EPA. There is no national database for these indirect discharges of wastewater pollutants.

TRI Water Discharges

Considerations

While TRI chemicals discharged to water are a key issue for some sectors (e.g., Food & Beverage Manufacturing, Forest Products), for most sectors, toxic chemicals emitted to air and/or disposed are a larger concern. Depending on the sector, this report describes TRI water discharges from 1996 through 2005 (the most current data available at the time of the analyses presented in this report), with a focus on current (2005) discharges. We do not present toxicity-weighted discharge values, because the RSEI methodology does not account for ecological toxicity, which is an important impact of water discharges.

Data Processing

Water discharges includes discharges to water (from section 5.3 of TRI Form R) and to Publicly Owned Treatment Works for metals only (from section 6.1 of TRI Form R).

Hazardous Waste Management

Several aspects of the BR influence the use of these data for EPA's Sector Strategies Program.

Considerations

Large quantity generators (LQGs) and RCRA hazardous waste treatment, storage and disposal facilities (TSDFs) are covered. Small quantity generators (SQGs) are not included.

LQGs and TSDFs are required to submit a biennial hazardous waste report. LQGs have one or more of the following characteristics: the site generated, in any single calendar month, 1,000 kg (2,200 lbs.) or more of RCRA hazardous waste; the site accumulated, during any calendar month, more than 1 kg (2.2 lbs.) of RCRA acute hazardous waste; or the site generated, in any single calendar month, or accumulated at any time, more than 100 kg (220 lbs.) of spill cleanup material contaminated with RCRA acute hazardous waste.

Note that many facilities in the sectors discussed in this report may not be required to report to BR; thus, the BR data presented may not cover all the activities of the entire sector.

Data Processing

This report describes hazardous waste generation in 2005 (the most current data available at the time of the analyses presented in this report), with a focus on the largest sources of hazardous waste generation. Data and documentation can be found at: **ftp.epa.gov/rcrainfodata/**.

For this report, data are compiled based on the primary 3-, 4-, 5-, and/or 6-digit NAICS codes reported to BR. For the Cement Manufacturing and Iron & Steel sectors, and specialty-batch chemicals subsector, data are compiled based on predetermined facility lists. The count of the number of facilities reporting hazardous waste data is a total of the number of unique RCRA IDs in the sector.

Only data flagged for inclusion in the National Biennial Report are included. States may submit information on facilities with other status designations, such as SQGs, as well as data on other state-regulated wastes that are exempt from federal regulation. These data, while submitted to BR, are not always included in the National Biennial Report. To mimic the National Biennial Report methodology, only data flagged for inclusion are included in the analysis conducted for this report.

Waste associated with source code G61 and management code H141 are excluded from this analysis to avoid double counting of stored wastes. This is consistent with the National Biennial Report methodology.

Waste Management Reported to TRI

Considerations

TRI reporting typically presents air and water releases in the broader category "Disposal or Other Releases." This report distinguishes waste management and disposal from releases to air and water, above, and presents the data in the categories discussed below.

Data Processing

"Recycling" means the quantity of the toxic chemicals that is either recovered at the facility and made available for further use or sent offsite for recycling and subsequently made available for use in commerce, as reported in sections 8.4 and 8.5 of TRI Form R.

"Energy Recovery" means the quantity of the toxic chemicals combusted in an onsite or offsite energy recovery device, such as a boiler or industrial furnace, as reported in sections 8.2 and 8.3 of TRI Form R.

"Treatment" means the quantity of chemicals destroyed in onsite or offsite operations such as biological treatment, neutralization, incineration, and physical separation, as reported in sections 8.6 and 8.7 of TRI Form R.

"Disposal" includes data from the following sections of TRI Form R:

- Section 5.4: Underground Injection onsite to Class I, II-V Wells
- Section 5.5: Disposal to land onsite

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- Section 6.2: Transfers to other offsite locations, for disposal codes only. The disposal codes are as follows:
  - M10 Storage only
  - M40 Solidification/Stabilization—Metals and Metal Compounds only
  - M41 Solidification/Stabilization—Metals and Metal Compounds only
  - M61 Wastewater Treatment (excluding POTW)—Metals and Metal Compounds only
  - M62 Wastewater Treatment (excluding POTW)—Metals and Metal Compounds only
  - M63 Surface Impoundment Recycling
  - M64 Other Landfills
  - M65 RCRA Subtitle C Landfills
  - M66 Subtitle C Surface Impoundment
  - M67 Other Surface Impoundment
  - M71 Underground Injection
  - M72 Offsite Disposal in Landfills
  - M73 Land Treatment
  - M79 Other Land Disposal
  - M81 Underground Injection to Class I Wells
  - M82 Underground Injection to Class II–V Wells
  - M90 Other Offsite Management
  - M91 Transfers to Waste Broker—Disposal
  - M94 Transfers to Waste Broker—Disposal
  - M99 Unknown

Comparing TRI and BR

Both TRI and BR contain information on waste. TRI includes information on toxic chemicals managed as waste. BR includes information on hazardous waste generated and managed. The quantities of hazardous waste reported to BR differ from those reported to TRI, because of numerous differences between the two systems, several of which are discussed below.

Differences in what is reported

TRI reporting is required for any toxic chemical (from a list of more than 600 chemicals) for which manufacturing, processing, or other use exceeds a reporting threshold. BR reporting is required for RCRA listed and characteristic hazardous wastes.

Differences in how quantities are reported

TRI includes the weight of the toxic chemicals within a waste stream, while RCRA reporting on hazardous wastes encompasses the weight of the entire waste or waste stream that meets the definition of RCRA hazardous waste. Therefore, hazardous wastes included in BR could be aqueous, solids, or sludges, weighing more than the toxic components portion alone. In addition, the waste streams reported to BR are considered hazardous, but may not contain constituents that are considered toxic as defined in TRI (e.g., waste streams may be hazardous to humans based on their ignitability, corrosivity, reactivity, toxicity, or hazardous constituents listed in 40 CFR 261 Appendix VIII).

Differences in reporting universes

There is overlap with some facilities reporting to both systems.

Differences in reporting frequency

TRI is annual; BR is every other year.

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aPPenDix: enDnoteS

Preface

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4. For more information on NEI, see the Data Sources, Methodologies, and Considerations chapter and **http://www.epa.gov/ttn/chief/trends/.**
5. For more information on TRI, see the Data Sources, Methodologies, and Considerations chapter and **http://www.epa.gov/tri.**
6. For more information on RSEI, see the Data Sources, Methodologies, and Considerations chapter and **http://www.epa.gov/oppt/rsei/.**
7. For more information on BR, see the Data Sources, Methodologies, and Considerations chapter and **http://www.epa.gov/epaoswer/hazwaste/data/biennialreport/**.

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9. EPA, *Cleaner Diesels: Low Cost Ways to Reduce Emissions from Construction Equipment*, March 2007.

10. Census Bureau, Annual Value of Construction Put in Place, http://www.census.gov/const/C30/total.pdf.

11. Truitt Degeare, EPA, Office of Solid Waste, communication with Peter Truit, EPA.

12. The NCDC compiles information on emissions reductions associated with voluntary diesel retrofits. Went, J., EPA Office of Transportation and Air Quality, communication Peter Truit, EPA, August 2007. Fewer retrofit technologies are available for NO_X than for $PM_{2.5}$, but the tonnage reduced is greater because NO_X emissions are heavier than $PM_{2.5}$ emissions. The NCDC database includes 85 projects, but emissions data are available for only 40 of them.

13. Associated General Contractors Survey, as reported in *2008 Associated Equipment Manufacturers Outlook*, p. 11, November 2007, http://www.aem.org/Trends/Reports/IndustriesOutlook/PDF/2008-Industries_Outlook.pdf. In sum, 17,596 AGC general contractor and specialty contractor member companies were surveyed by email.

14. EPA, *Measuring Construction Industry Environmental Performance*, September 2007, p. 35, http://www.epa.gov/ispd/construction/perfmeasures.pdf.

15. Science Applications International Corporation, prepared for EPA, *Economic Analysis of the Final Phase II Storm Water Rule*, October 1999, p. 2-2: "When land is disturbed by construction activities, surface erosion increases 10-fold on sites formerly used for crop agriculture, 200 times on sites formerly under pasture, and 2,000 times on sites formerly forested."

16. EPA and authorized states establish general National Pollutant Discharge Elimination System (NPDES) permits that codify specific site management practices and reporting requirements. Further information is available at the EPA website http://cfpub.epa.gov/npdes. Additional information on construction stormwater is available at the Construction Industry Compliance Assistance Center website, http://www.cicacenter.org.

17. Data in the figure were adjusted to account for multiple NOI submissions for the same construction project and for projects not requiring an NOI because of acreage thresholds or waivers. However, the denominator (number of projects) overestimates the number of projects requiring an NOI because (1) a single construction site may be counted multiple times if it happens to include multiple project types, and (2) the number of projects includes renovations and additions, which may not require an NOI.

18. Colorado Department of Public Health, *Colorado Stormwater Excellence Program—Pilot Stage I—Final Report*, http://www.cdphe.state.co.us/wq/PermitsUnit/stormwater/CSEPstage1.pdf.

19. Currently, there is no centralized source of data on quantities of C&D materials generated or recycled. Source of estimates: EPA's Municipal and Industrial Solid Waste Division, Office of Solid Waste. *Characterization of Building-Related Construction and Demolition Debris Materials in the United States (DRAFT)*, July 2006. Considerable uncertainties are associated with these estimates; EPA is seeking to develop a methodology for more accurate measurement.

20. Kim Cochran, EPA Office of Solid Waste, communication with Peter Truit, EPA.

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21. EPA's Office of Solid Waste. *Characterization of Road and Bridge Related Construction and Demolition Debris Materials in the United States (DRAFT)*, October 2005.

22. Turner Construction Company, Green Buildings website, http://www.turnerconstruction.com/greenbuildings/content.asp?d=2199.

23. These examples are state-specific, and further research must address the variation among the states and the reasons for short-term anomalies, such as the sudden drop in recycling in Maryland in 2003. Additional information on C&D recycling is available on EPA's website, http://www.epa.gov/epaoswer/non-hw/debris-new/index.htm.

24. *Recycling Construction Materials—An Important Part of the Construction Process*, by Kimberly Cochran and Nicole Villamizar, in Construction Business Owner magazine, July 2007, http://www.constructionbusinessowner.com/topics/environment-and-compliance/recycling-construction-materials-an-important-part-of-the-construction-process.html.

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27. EPA, *National Biennial RCRA Hazardous Waste Report*, 2005, http://www.epa.gov/epaoswer/hazwaste/data/biennialreport/.

28. EPA, *National Biennial RCRA Hazardous Waste Report*, 2005.

29. "Green building" in this chapter focuses on measuring performance only during the construction phase of the built environment. It does not address activities prior to construction such as siting and design, or post-construction activities such as the operation of structures.

30. Green Building Council, LEED Rating Systems, http://www.usgbc.org/LEED. See also, https://www.usgbc.org/ShowFile.aspx?DocumentID=1095. Other programs include the Green Building Initiative's Green Globes system and the National Association of Homebuilders' Model Green Home Building Guidelines.

31. EPA, Sector Strategies Program, *Measuring Construction Industry Environmental Performance*, September 2007, http://www.epa.gov/sustainableindustry/construction/perfmeasures.pdf.

32. EPA Sector Strategies, *Measuring Construction Industry Environmental Performance*, September 2007, p. 10, http://www.epa.gov/sectors/construction/.

33. Adapted from paper submitted by Oscar J. Boldt Construction Company to Melinda Tomaino, AGC of America, for a future publication on green construction.

34. The LEED Professional Accreditation program is now managed by the Green Building Certification Institute (GBCI), http://www.gbci.org/.

35. Melinda Tomaino, AGC of America, personal communication with Peter Truitt, EPA.

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1. *Facilities:* Census Bureau, CBP, 2005 (*Facilities:* Primary commodity processing (PCP)=800, Animal production (AP)=5,000, Other agribusiness (OT)=24,000); *Employment:* PCP=45,000, AP=545,000, OT=1 million.); *Value of shipments:* DOC, BEA: Industry Economic Accounts, http://www.bea.gov/industry/ (*Value of shipments:* PCP=$43.4 billion, AP=$171.9 billion, OT=$394 billion).

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4. DOE, EIA, MECS, 2002 Data Tables, as discussed in EPA Sector Strategies Program, *Energy Trends in Selected Manufacturing Sectors: Opportunities and Challenges for Environmentally Preferable Energy Outcomes*, March 2007, p. 3-31, 3-32.

5. Willis Sneed, Project Manager, HDR Engineering, Inc., personal communication with Daniel Kaiser, EPA, January 4, 2008.

6. EPA, TRI, 2005 PDR.

7. Walt Tunnessen, EPA, Climate Protection Partnership Division, personal communication with Daniel Kaiser, EPA, October 4, 2007.

8. EPA, TRI, 2005 PDR, modeled through EPA's RSEI. Includes facilities that report primary SIC codes 20 and 5461 on their Form R.

9. EPA's NEI for Point Sources: Final v3 2002. Data compiled from EPA's facility summary datasets. Includes facilities with NAICS codes 311 and 3121 or SIC codes 20 and 5461.

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18. EPA, TRI, 2005 PDR.

19. EPA, Office of Water, Wastewater Management, "Factsheet: Proposed MSGP 2006," p. 6, http://www.epa.gov/npdes/pubs/msgp2006_factsheet-proposed.pdf.

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23. EPA, TRI, 2005 PDR.

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5. EPA, Sector Strategies Program, Forest Products, http://www.epa.gov/sectors/forest/index.html.
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13. EPA, TRI, 2005 PDR.
14. EPA, TRI, 2005 PDR, modeled through EPA's RSEI.
15. EPA, TRI, 2005 PDR, modeled through EPA's RSEI.
16. Prior to the 1997 clarification, most mills would not have reported these metals to TRI based on the "de minimis" exemption. For additional information, please see the final Federal Register notice, published May 1, 1997, 62 FR 23834.
17. AF&PA, Environmental, Health, & Safety Verification Program, Biennial Report, 2006, p. 2, http://www.afandpa.org.
18. Loren Blosse, AF&PA, "AF&PA Members Reduce Greenhouse Gas Emissions," press release, October 29, 2007.
19. AF&PA member companies manufacture more than 84% of the paper and 62% of the wood products made in the United States. These numbers were developed under the protocol developed by AF&PA and the forest industry's environmental research organization, the National Council for Air and Stream Improvement (NCASI) for DOE's Climate VISION program.
20. Loren Blosse, AF&PA, "AF&PA Members Reduce Greenhouse Gas Emissions," press release, October 29, 2007.
21. These numbers were developed under the protocol developed by AF&PA and NCASI for the Climate VISION program.
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23. EPA, TRI, 2005 PDR.
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34. AF&PA, Agenda 2020 Technology Alliance.
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2. *Energy Use:* DOE, EIA, Manufacturing Energy Consumption Survey (MECS), 2002, Table 3.1, http://www.eia.doe.gov/emeu/mecs/contents.html; *Emissions of Criteria Air Pollutants:* EPA, National Emission Inventory (NEI) for Point Sources: Final v3 2002. *Chemicals Reported to TRI:* EPA, TRI, 2005 Public Data Release (PDR), freeze date: December 19, 2006; *Hazardous Waste Generated and Managed:* EPA, 2005 National Biennial RCRA Hazardous Waste Report, http://www.epa.gov/epaoswer/hazwaste/data/biennialreport.
3. USGS, Iron and Steel, January 2007, http://minerals.usgs.gov/

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minerals/pubs/commodity/iron_&_steel/festemcs07.pdf; see 2006 report for comparable narrative and sources.

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6. DOE, EIA, MECS, 2002 Data Tables, Table 3.2, Energy Consumption as a Fuel, http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html.

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9. AISI, personal communication with Tom Tyler, EPA, February 4, 2008.

10. EPA, *Energy Trends in Selected Manufacturing Sectors: Opportunities and Challenges for Environmentally Preferable Energy Outcomes*, p. 3-55. Fractions based on 1998 MECS data.

11. DOE, Office of Energy Efficiency and Renewable Energy, Industrial Technologies Program; *Steel Industry Marginal Opportunity Study*, September 2005, p. 8, http://www1.eere.energy.gov/industry/steel/pdfs/steelmarginalopportunity.pdf.

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16. Facility count is by TRI ID. A facility can have more than one TRI ID.

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18. EPA, TRI, 2005 PDR, modeled thrugh EPA's RSEI.

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23. Information current as of June 26, 2008; see End of Life Vehicle Solutions Corporation, http://www.elvsolutions.org.

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44. Steel Recycling Institute, "Steel Recycling in the U.S. Continues Its Record Pace In 2005" (press release), April 26, 2006, http://www.recycle-steel.org/PDFs/2005Release.pdf.

45. Jennifer R. Kaduck, Georgia Environmental Protection Division, *Innovative Solutions Towards the Elimination of Land Disposal of Electric Arc Furnace Emission Control Dust (Hazardous Waste K061)*, http://www.p2pays.org/ref/21/20282.pdf.

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13. Includes direct discharges to waterways of any TRI chemical and discharges of metals to POTWs.

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1. See EIA website: http://www.eia.doe.gov/oiaf/aeo/.

2. Federal Register notice 71 FR 32464 (June 6, 2006). The rule became effective for reporting forms due to EPA by July 1, 2007.

3. See Article 4(1)(a) of the United Nations Framework Convention on Climate Change http://www.unfccc.int. Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15. Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available...national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the *Montreal Protocol*, using comparable methodologies..." Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See http://unfccc.int.

4. See http://www.epa.gov/fedrgstr/EPA-WATER/2006/June/Day-01/w8496.htm.

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