Oil Refinery Permits

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A Handbook for Citizen Participation in the Permitting of Oil Refineries under the New Source Review Provisions of the Clean Air Act

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Oil Refinery Permits

A Handbook for Citizen Participation in the Permitting of Oil Refineries under the New Source Review Provisions of the Clean Air Act

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The Environmental Integrity Project (EIP) is a nonpartisan, nonprofit organization established in March of 2002 by former EPA enforcement attorneys to advocate for more effective enforcement of environmental laws. EIP has three objectives: 1) to provide objective analyses of how the failure to enforce or implement environmental laws increases pollution and affects the public's health; 2) to hold federal and state agencies, as well as individual corporations, accountable for failing to enforce or comply with environmental laws; and 3) to help local communities obtain the protection of environmental laws. An electronic copy of this Manual can be downloaded free of charge from the EIP website at www.environmentalintegrity.org.

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Oil Refinery Permits

A Handbook for Citizen Participation in the Permitting of Oil Refineries under the New Source Review Provisions of the Clean Air Act

Introduction

Petroleum refineries emit millions of pounds of air pollution that poses a serious risk of harm to human health and the environment and impairs the quality of life for the people living in nearby communities. Carcinogens and other pollutants are released directly into the predominantly low-income and minority neighborhoods that typically share the refinery fencelines, and many refineries are located in areas that already do not meet federal air quality standards set to protect public health. Further, the environmental consequences of refinery pollution range from acid rain to global warming.

Common air pollutants released from oil refineries include volatile organic compounds (VOCs),[1] sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM),[2] carbon monoxide (CO), hydrogen sulfide (H_2S), and sulfuric acid aerosol (or "mist"). Many of the pollutants emitted by refineries are "hazardous air pollutants" ("HAPs"), [3] such as benzene, 1,3 butadiene, hexane, 1,2,4-trichlorobenzene, toluene, xylenes, propylenes, naphthalene, carbon disulfide, carbonyl sulfide, selenium compounds, nickel compounds, chromium compounds, cadmium compounds, hydrogen fluoride (hydrofluoric acid ("HF")), and formaldehyde.[4] Many refinery pollutants are also "OSHA carcinogens,"[5] such as polycyclic aromatic hydrocarbons ("PAHs" or "polycyclic aromatic compounds" ("PACs")), benzene, ethylbenzene, 1,3-butadiene, naphthalene, styrene, tetrachloroethylene, formaldehyde, and metals such as nickel and

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[1] Numerous VOCs emitted by refineries – such as benzene; 1,3 butadiene; toluene; and xylenes – are toxic air pollutants – those known or suspected to cause cancer or other serious human health problems.

[2] "Particulate matter" includes "total suspended particulates" ("TSP"), PM_{10} (particulate matter between 2.5 and 10 micrometers in diameter), and $PM_{2.5}$ (particulate matter less than or equal to 2.5 micrometers in diameter).

[3] HAPs are pollutants "which are known to be, or may reasonably be anticipated to be, carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic … or [which cause] adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise…." Clean Air Act § 112(b)(2), 42 U.S.C. § 7412(b)(2).

[4] *See* Clean Air Act § 112(b)(1), 42 U.S.C. § 7412. The original list of 189 HAPs promulgated as part of the Clean Air Act Amendments of 1990 can also be found at http://www.epa.gov/ttn/atw/orig189.html.

[5] "OSHA carcinogens" are "[U.S. EPA Toxics Release inventory ('TRI')] chemicals that are classified as carcinogens under the requirements of the Occupation Safety and Health Administration (OSHA)…." *See* http://www.epa.gov/tri/chemical/.

lead.[6] In addition, oil refineries are one of the largest producers of greenhouse gases, including carbon dioxide (CO_2), and methane (CH_4).[7]

Human health effects caused by these pollutants include premature death; cancer; respiratory illness; aggravation of heart conditions and asthma; permanent lung damage; reproductive, neurological, developmental, respiratory, and immunological problems; bio-mutations; and cardiovascular and central nervous system problems.[8] Environmental damage caused by these pollutants includes global warming; acid rain; concentration of toxic chemicals up the food chain; the creation of ground level ozone and smog; visible impairments that migrate to sensitive areas such as National Parks; and depletion of soil nutrients.[9] Refinery emissions also reduce the quality of life for nearby communities with noise, foul odors, and periodic requirements to remain indoors until winds carry toxic emissions away.

In addition, a trend toward expanding, modifying, and building refineries to process "tar sands"[10] from Canada is gaining momentum.[11] Beneath the boreal forest[12] of

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[6] *See* http://www.epa.gov/tri/chemical/carcinog.pdf.

[7] This list of pollutants is by no means comprehensive. The EPA notes that "in 1993 the petroleum refining industry released … and transferred … a total of 482 million pounds of pollutants, made up of 103 different chemicals." EPA document EPA/310-R-95-013, "EPA Office of Compliance Sector Notebook Project – Profile of the Petroleum Refining Industry," U.S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance (Sept. 1995) at 42, *available at* http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/petrefsnpt1.pdf (*hereinafter* "EPA Refinery Sector Notebook").

[8] EPA Office of the Inspector General, "EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts" (June 22, 2004), Appendix D, *available at* http://www.epa.gov/oig/reports/2004/20040622-2004-P-00021.pdf (*hereinafter* "EPA OIG Report").

[9] *Id*.

[10] Tar sands are also sometimes called "oil sands" (reflecting the desire of developers to promote a more benign-sounding name), "extra-heavy crude," or "heavy crude," and consist of about 85% sand, clay, and silt; 5% water; and 10% crude bitumen (the "tar" that can be converted to oil). Ann Bordetsky, *et al*., "Driving It Home: Choosing the Right Path for Fueling North America's Transportation Future" at 5 (Natural Resources Defense Council, the Pembina Institute, and Western Resource Advocates, June 2007), *available at* http://www.nrdc.org/energy/drivingithome/contents.asp (*hereinafter* "Driving It Home"). The bitumen itself is so viscous that it does not flow at room temperature, and can be used as a sealant or paving material. Elizabeth Kolbert, "Unconventional Crude – Canada's Synthetic-fules Boom," The New Yorker, Nov. 12, 2007, at 46, *abstract available at* http://www.newyorker.com/reporting/2007/11/12/071112fa_fact_kolbert (*hereinafter* "Unconventional Crude").

[11] A thorough discussion of "tar sands" is beyond the scope of this Handbook, but it is mentioned here to highlight an emerging issue in the area of refinery expansion, and to point out a few of the alarming environmental consequences of obtaining oil and gasoline from tar sands. For a more thorough discussion of this issue, *see* Driving It Home, *supra* note 10. *See also*, numerous documents and reports regarding tar sands from the Pembina Institute, available at http://www.oilsandswatch.org/, including Dan Woynillowicz, "Oil Sands Fever – the Environmental Implications of Canada's Oil Sands Rush" (The Pembina Institute, Nov. 2005) at 22, *available at* http://pubs.pembina.org/reports/OilSands72.pdf (*hereinafter* "Oil Sands Fever").

Alberta, Canada lays an area the size of Florida containing tar sands. Due to rising gasoline prices, these "bottom of the barrel" reserves have recently become commercially viable to extract, placing Canada second only to Saudi Arabia in oil reserves (and more than Kuwait, Norway, and Russia combined).[13] With some experts predicting the "peaking" of conventional oil production in the near future, and given the political stability of Canada relative to the Middle East, the petroleum industry is increasingly eyeing Alberta as the next Saudi Arabia.[14] However, the environmental costs of mining and refining tar sands are staggering. Mining the deposits lying relatively close to the surface means clear-cutting and strip-mining huge portions of intact boreal forest ecosystem, turning it into enormous open-pit mines as large as three miles wide and 200 feet deep.[15] In fact, "[i]n any given load of sands, only about 10 percent is bitumen … [so] [f]or every *barrel* of synthetic crude …, *forty-five hundred pounds* of tar sands have to be dug up and separated."[16] To obtain deeper reserves, a water and energy-intensive process of steam-injection, called "steam assisted gravity drainage" ("SAGD, pronounced "sag-dee") is used. Each barrel of oil from tar sands requires 2.5 – 4 times as much water to produce as does conventional oil,[17] and nearly all of this water ends up in vast toxic

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[12] The Sierra Club has stated: "The northern boreal ecoregion accounts for about one third of [the earth's] total forest area. It is comprised of a broad circumpolar band which runs through most of Canada, Russia, Scandinavia and parts of Northern Scotland." *See* http://www.sierraclub.org/ecoregions/boreal.asp. The New Yorker also reports: "Spread over 1.4 billion acres, Canada's boreal forest is considered one of the largest still intact ecosystems on the planet." Unconventional Crude, *supra* note 10.

[13] Unconventional Crude, *supra* note 10.

[14] For example, at the time of publication of this Handbook, ConocoPhillips plans to invest $4 billion in its huge Wood River Refinery in Roxana, Illinois to process tar sands, British Petroleum ("BP") plans to invest $3 billion in its massive Whiting, Indiana refinery to process tar sands, Hyperion Resources is contemplating building an enormous new 400,000 barrel per day refinery in South Dakota (sometimes called the "Gorilla Project" due to its size) to process tar sands, Murphy Oil Corp. has plans for an enormous $6 billion, 7-fold expansion of its refinery on Lake Superior in Wisconsin to process tar sands, Marathon Petroleum Co. is planning a $1.9 billion expansion of its Detroit, Michigan refinery to process tar sands (and may also be considering tar sands expansions at its Robinson, Illinois; St. Paul Park, Minnesota; and Garyville, Louisiana refineries), and Husky Energy, Inc. may be considering a tar sands expansion of its refinery in Lima, Ohio. In November of 2007, The New Yorker reported that "[over] the next five years, investment in [Canadian tar sands development] is expected to amount to more than seventy-five billion dollars." Unconventional Crude, *supra* note 10. *See also*, Russell Gold, "As Prices Surge, Oil Giants Turn Sludge Into Gold," Wall Street Journal, Mar. 27, 2006, at A1 (*hereinafter* "Sludge Into Gold"). "Synthetic crude" production from tar sands already "tops a million barrels a day," and is expected to double to 2010 and triple by 2015. Unconventional Crude, *supra* note 10.

[15] Driving it Home, *supra* note 10, at 5. *See also*, Unconventional Crude, *supra* note 10: "Before mining begins, everything above the feed – trees, bushes, grass, soil, rocks, wildlife – gets scooped up and carted away. (The material is delicately referred to as 'overburden.') … [Suncor official Darin] Zandee said, 'We try to move a million tons a day.'"

[16] Unconventional Crude, *supra* note 10 (emphasis added).

[17] Dan Woynillowicz and Chris Severson-Baker, "Down to the Last Drop – the Athabasca River and Oil Sands – Oil Sands Issue Paper No. 1" (The Pembina Institute, Mar. 2006) at ii, *available at* http://pubs.pembina.org/reports/LastDrop_Mar1606c.pdf (*hereinafter* "Down to the Last Drop"). The Pembina Institute elaborated in 2006: "Approved and operating oil sands operations are allowed to withdraw 349 million cubic metres (m^3) of water per year – that's enough water to meet the needs of a city of two million people, a population twice the size of the City of Calgary. Planned oil sands projects will

lakes (which the oil industry euphemistically calls "tailings ponds"). The Canadian National Energy Board (a federal regulatory body), has explained that "[t]here is currently no demonstrated means to reclaim fluid fine tailings."[18] So far (and just getting started), these "tailings ponds" comprise about *20 square miles of non-reclaimable toxic lakes* of mining waste, so vast that they can be seen from space, where once was pristine forest.[19] Tar sands extraction also requires an enormous amount of energy – in fact, "[s]o much heat is required to separate the oil from the tar that Total [Petrochemicals] briefly floated the idea of building a nuclear-power plant [in Northern Canada],"[20] and "for every three barrels extracted via SAGD, one has, in effect, been consumed."[21] Perhaps most importantly, due to the huge amounts of energy needed to extract and refine tar sands, producing oil from tar sands releases approximately *three times* as much global-warming causing "greenhouse gas" as does conventional crude oil production.[22]

Despite these significant consequences to public health and the environment, the public faces substantial barriers to participation in the permitting of oil refineries. Chief among these barriers are the burdensome tasks of wading through technically daunting proposed permits and navigating the often Byzantine permitting processes; that is, determining when and how to be effectively heard. This Handbook presents a "plain English" explanation of the permitting process and how to participate, as well as a concise description of what to look for – and *ask* for – in a permit to operate an oil refinery under the Clean Air Act.

Clean Air Act permits issued to oil refineries are permits given to private companies by our government on behalf of us to pollute the air that we breathe. Public participation is a right, and effective participation makes a real difference in the quality and stringency of the permits under which refineries must operate. Better permits mean a cleaner global environment, as well as improved health and quality of life for the people who must live with the refineries in their back yards.

How this Handbook is Organized

Oil refineries are subject to two principal types of Clean Air Act permits: "New Source Review" ("NSR") permits (sometimes called "construction permits") and "Title

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increase water withdrawals more than 50% higher to 529 million m^3 per year – more water than is used by the City of Toronto in a year." *Id*.

[18] Sludge Into Gold, *supra* note 14, at A1. *See also*, Unconventional Crude, *supra* note 10: "Suncor [alone] has nine such ponds, which collectively cover an area of eleven square miles."

[19] *See* Driving it Home, *supra* note 10, at 8, *citing* Oil Sands Fever, *supra* note 11, at 30.

[20] Sludge Into Gold, *supra* note 14, at A1. The Energy Alberta Corporation may currently be seeking to build two nuclear reactors in Alberta. Unconventional Crude, *supra* note 10. Currently, natural gas is used to generate such heat. The New Yorker reported in November of 2007 that "[i]t is estimated that by 2012 tar-sands operations will consume two billion cubic feet of natural gas a day, or enough to heat all the homes in Canada." *Id*.

[21] *Id*.

[22] Driving it Home, *supra* note 10, at 7, *citing* Oil Sands Fever, *supra* note 11, at 22.

V" permits (so called because they are issued pursuant to Title V of the Clean Air Act ("CAA" or "the Act")).[23] While the NSR construction permits impose new limits and requirements, the Title V permit compiles all the requirements applicable to a facility (including the NSR permit requirements) into a single document and requires the refinery to assure compliance with the CAA and all permit requirements. Since Title V permits incorporate the specific requirements of the NSR permits, there generally are not Title V issues (apart from the NSR issues) which are specific to oil refineries. Therefore, this Handbook addresses only citizen participation in the development and issuance of NSR construction permits, and does not address Title V issues. However, for an excellent and detailed guide to participation in the Title V permitting process, *see* "The Proof is in the Permit – How to Make Sure a Facility in Your Community Gets an Effective Title V Air Pollution Permit," available at http://nsdi.epa.gov/oar/oaqps/permits/partic/proof1.pdf.[24]

The first section of this Handbook provides an overview of the law and the permitting processes involved in issuing NSR construction permits. The section on the "law" will explain what the permit is, what it is supposed to do, and where it fits in the broader scheme of the Clean Air Act. The section on the "process" will explain how the permitting authorities go about drafting and issuing the permits, and where and how in the process the public can participate.[25]

The second section will present a brief discussion of the major processes involved in oil refining and identify the technology and pollutants associated with those processes.

The third section of this Handbook will discuss the key issues that should be addressed in refinery NSR permits, and/or raised by citizens in commenting on or challenging proposed NSR permits for oil refineries. This section will include a recitation of the specific technologies to ask for, relevant to each of the main oil refinery processes.

[23] Refineries are subject to a number of other provisions of the CAA as well, as noted below, including the New Source Performance Standards ("NSPS") which mandate "best demonstrated technology" ("BDT"), National Emission Standards for Hazardous Air Pollutants ("NESHAPs") which mandate maximum achievable control technology ("MACT") requirements for hazardous air pollutants ("HAPs"), and reasonably available control technology ("RACT") requirements applicable to all existing refineries in non-attainment areas.

[24] Keri Powell, *et al*., "The Proof is in the Permit – How to Make Sure a Facility in Your Community Gets an Effective Title V Air Pollution Permit," (Larry Shapiro, ed., New York Public Interest Research Group Fund, Inc., and The Earth Day Coalition, Inc., June 19, 2000), *available at* http://www.titlev.org/t5book.htm (*hereinafter* "Proof is in the Permit").

[25] This Handbook strives to present an overview of the *federal* NSR program sufficient to allow citizens to navigate the permitting process, but does not attempt to address variations in *state* NSR programs. However, each state's NSR program is incorporated into its "State Implementation Plan" ("SIP"), which can be found in the U.S. Code of Federal Regulations ("C.F.R.") at 40 C.F.R. Part 52.

"The ABCs of NSR - A Citizen's Guide to the Clean Air Act's New Source Review Permitting Process"[26] is an excellent guide to the law and process of the NSR program in general, upon which this Handbook has relied and to which it owes a great debt of gratitude. This Handbook does not attempt to reiterate that detailed discussion. Rather, following a brief overview of NSR law and process, this Handbook focuses on the specific issues, particular to oil refineries, that should be addressed in refinery permits and/or raised by citizens in commenting on or challenging refinery permits.

Finally, Appendix A to this Handbook contains a concise "bullet point" summary of the most important substantive items to watch for when reviewing and commenting on a proposed refinery NSR construction permit, and Appendix B contains a list of specific technologies to ask for with regard to particular refinery processes.

I. OVERVIEW OF NEW SOURCE REVIEW

A. The Law

The essence of the New Source Review ("NSR") program, created as part of the 1977 amendments to the Clean Air Act, is that major stationary sources of air pollution must not significantly degrade air quality in regions which already meet national air quality standards, and such sources must not add any new pollution in regions which do not meet such standards. Any "major stationary source"[27] which is to be newly built, and any existing major source which intends to undergo a "major modification,"[28] must obtain an NSR permit before commencing construction, and the public must be afforded an opportunity to review and comment on the draft permit before issuance.[29] That permit

[26] "The ABCs of NSR - A Citizen's Guide to the Clean Air Act's New Source Review Permitting Process," Laura Haight, Principal Author and Editor; Contributing Authors: Lisa F. Garcia, Jason K. Babbie, and Kelly Haragan (New York Public Interest Research Group Fund, Dec. 2005) (*hereinafter* "ABCs of NSR").

[27] Oil refineries are considered "major stationary sources" if they emit 100 tons per year ("tpy") or more of any "criteria pollutants," including "fugitive emissions." *See* 40 C.F.R. § 52.21(b)(1)(i)(a). ("Criteria pollutants" and "fugitive emissions" are discussed below). In practice, there is almost certainly no question that every oil refinery in the United States qualifies as a "major stationary source."

[28] A modification is considered "major" if the "net increase" in emissions or potential emissions (discussed more fully below) meets *any* of the thresholds for the various pollutants listed at 40 C.F.R. § 51.166(b)(23)(i) (*see* Appendix C), *or* if the modification occurs within 10 kilometers of a "Class I area" (such as certain "wilderness areas" (*see* Appendix I) and the increased emissions would effect the air quality of the Class I area by increasing the 24-hour average concentration of any regulated pollutant in the ambient air by at least one microgram per cubic meter (1 $\mu g/m^3$). 40 C.F.R. § 52.21(b)(23)(iii).

[29] Note that the NSR thresholds regarding construction of "new" facilities are different from those regarding "major modifications" of existing facilities. A newly constructed refinery (built from scratch) would require an NSR permit if it met the 100 tpy threshold, but a "major modification" of an existing "major source" refinery would require an NSR permit if it met any of the "significant net increase" thresholds found at 40 C.F.R. § 52.21(b)(23)(i). Further, a modification to a "*minor* source" refinery would require an NSR permit only if the modification *itself* qualified as a "major source" (*i.e.*, resulted in a net increase of 100 tpy of any criteria pollutant), and a modification to "minor source" refinery which did *not* qualify as a "major modification" (*i.e.*, as a "major source" in its own right for resulting in 100 tpy) would not require an NSR permit, but would be relevant for future expansion permits if the total emissions then qualified the refinery as a "major source." However, the construction of new oil refineries is now

will include requirements, among others, to install modern pollution control technology. Thus, one important aspect of the NSR program is that it gradually requires aging facilities (those in existence in 1977 when the NSR program was enacted – *i.e.*, *all* of the current refineries in the U.S.) to install modern pollution control technology, which complies with the requirements that would apply to any newly constructed facility, as they upgrade or expand.[30]

The Clean Air Act requires the U.S. Environmental Protection Agency ("EPA") to establish national air quality standards with regard to six common air pollutants which are known hazards to human health and the environment, called "criteria pollutants." These "criteria pollutants" are sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter (PM), ground-level ozone (O_3), and lead (Pb). The air quality standards applicable to the criteria pollutants are known as "National Ambient Air Quality Standards" ("NAAQS"). The Act further defines numerous "air quality regions," which together encompass the entire United States. States monitor the criteria pollutants in the air quality regions and report the results to the EPA. If a region meets the NAAQS for a particular criteria pollutant, it is said to be an "attainment area" for that pollutant; if a region does not meet the NAAQS for a pollutant, it is a "non-attainment area" for that pollutant.[31] The Clean Air Act seeks to protect the air quality in attainment areas, and to bring non-attainment areas into attainment.

The NSR program treats facilities differently depending upon whether they are in an "attainment area" or a "non-attainment area." If a facility is in an attainment area, then it must obtain a "Prevention of Significant Deterioration" ("PSD") permit regarding

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extremely rare (a new refinery has not been built in the United States since 1976), and all refineries almost certainly qualify as "major stationary sources." Therefore, in practice, any refinery expansion requires an NSR permit if any increased emissions meet the "significant net increase" thresholds found at 40 C.F.R. § 52.21(b)(23)(i). Nevertheless, at the time of publication of this Handbook, four brand new oil refineries are being considered: 1) the Mandan, Hidatsa and Arikara ("MHA") Nation is contemplating building an approximately 15,000 barrel per day ("bpd") refinery on its Indian Reservation in North Dakota; 2) Hyperion Resources is contemplating building an enormous 400,000 bpd refinery in South Dakota (sometimes called the "Gorilla Project" due to its size); 3) Arizona Clean Fuels Yuma is proposing build a 150,000 bpd refinery in Yuma County, Arizona; and 4) the State of North Dakota is contemplating the construction of a state-owned refinery. These new refineries would be subject to the 100 tpy threshold, but there is almost certainly no question that these refineries would meet that threshold.

[30] Because facilities in existence in 1977 were "grandfathered" (exempted from NSR provisions until they underwent "major modifications") – including all of the refineries currently existing in the U.S. – many of the oldest and dirtiest facilities continue to pollute without modern pollution control technology. Further, existing "grandfathered" major sources often attempt to (and do) escape NSR requirements (and, arguably, the intent of Congress in enacting the 1977 Clean Air Act Amendments) by characterizing modifications as less than "major." Such attempts, which you should watch for when reviewing proposed permits, are discussed below.

[31] The "attainment" or "non-attainment" of a region is specific to each of the six criteria pollutants. Therefore, it is possible for a region be in attainment for some pollutants, but in non-attainment for others. Non-attainment areas are listed at http://www.epa.gov/oar/oaqps/greenbk/multipol.html.

that pollutant;[32] if it is in a non-attainment area, then it must obtain a "Non-Attainment Area New Source Review" ("NA NSR") permit.[33] Note, again, that a facility may be in an area that is in attainment for some criteria pollutants but not for others, such that it would be required to obtain both a PSD and an NA NSR permit.

The goals of a PSD permit are: 1) to prevent an attainment area from slipping into non-attainment, and 2) to prevent "significant" (but allowing some) deterioration of existing "good" air quality. Therefore, a PSD permit: 1) must not allow any emissions that would violate a NAAQS for any criteria pollutant, and 2) must not allow emissions in excess of any "PSD increment." A PSD increment is the amount of a regulated pollutant that can be added to an attainment area's total load of that pollutant above the area's "baseline concentration."[34] The baseline concentration is essentially the amount of the pollutant already in the air when the first complete PSD permit application affecting the area was submitted.[35] Note that not only must a PSD permit prevent any "significant deterioration" by limiting increased pollution to the "increment" limits, but it must also prevent any NAAQS violation (which would push the area into "non-attainment"). That is, while the NAAQS limit is the absolute ceiling beyond which a pollutant concentration cannot go, the PSD increment is the amount of allowable increase of a pollutant, so that increases must be prevented if they reach the NAAQS "ceiling," *even if* the allowable PSD increment has not been completely used.

The goal of an NA NSR permit is to ensure that new construction/modification does not hinder a non-attainment area's progress toward attainment. Therefore, an NA NSR permit must require the applicant to obtain "offsets" (or "emission reduction credits" ("ERCs")) from emission reduction projects at the same source or from other existing sources in the same area. The offset must be *at least* as much as the increase of the criteria pollutant (that is, the "offset ratio" of reductions to new emissions must be at

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[32] If data regarding a region is insufficient for classification, then it is said to be "unclassifiable" and regulated as if it were in attainment (although logic might dictate that the assumption in the face of uncertainty should be the opposite).

[33] Although both PSD and NA NSR permits are issued under the NSR program, the NA NSR permit is often referred to as an "NSR permit." In addition, *both* types of permits are sometimes (somewhat confusingly) referred to as "NSR permits." Since either or both permits are necessary prior to construction, they are also commonly referred to collectively as "construction permits" or "pre-construction permits." This Handbook will refer to an attainment area permit as a "PSD permit," a non-attainment area permit as an "NA NSR permit," and both types of permits issued under the NSR program as "construction permits."

[34] The EPA has set "PSD increments" for only three pollutants: PM_{10} (particulate matter between 2.5 and 10 micrometers in diameter), SO_2, and NO_2. The amount of the increment (maximum allowable increase) depends on whether the area is "class I," "class II," or "class III," with "class I" being the most sensitive areas (such as wilderness areas) having the lowest increment and "class III" having the highest increment. *See* 40 C.F.R. § 52.21(c) and (e) for the specific increments and class I designations.

[35] "Draft New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting," (U.S. Environmental Protection Agency, Oct. 1990) at C.6, *available at* http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf (*hereinafter* "EPA NSR Workshop Manual").

least 1:1).[36] In addition, the offset ratios for NO_X and VOCs in ozone non-attainment areas are greater than 1:1, and the offsets increase depending upon the severity of the non-attainment.[37]

Finally, both PSD and NA NSR permits must require the installation of modern pollution control technology. The level of pollution control technology required in the construction permits will be based on whether the facility is in an attainment area or a non-attainment area; that is, whether the permit is a PSD or an NA NSR permit. If the permit is a PSD permit, then the CAA requires the use of "best available control technology" ("BACT"), but if the permit is an NA NSR permit, then the CAA requires the use of "lowest achievable emission rate" ("LAER") technology. Both BACT and LAER are stringent limitations that require the most technologically feasible pollution control. However, while the BACT determination takes into consideration "economic impacts,"[38] the LAER determination may not consider cost-effectiveness.[39] Therefore, LAER is the most stringent pollution control possible. The determination of what specific technology qualifies as BACT or LAER (which is made on a case-by-case basis for each pollutant from each emission unit in each permit) is a fundamental issue that will be explored in greater detail in section III of this Handbook (*see also*, Appendix B).

This Handbook discusses the federal NSR program. However, construction permits are usually issued by state permitting authorities (for example, construction permits in Texas are issued by the Texas Commission on Environmental Quality ("TCEQ")). While all state NSR programs must be at least as stringent as the federal NSR program, some states have developed their own programs (approved by the U.S. EPA). State programs that simply follow the federal model are called "delegated programs," and state programs that deviate from the federal model are called "approved programs." Some approved programs are more stringent than the federal program, and/or may have other differences. Each state's NSR program is included in its "State Implementation Plan" ("SIP"), which is the entire set of laws and regulations, also approved by the U.S. EPA, by which the state hopes to achieve and/or maintain federal air quality standards. All state SIPs are set forth at 40 C.F.R. Part 52. Although the myriad state variations cannot be addressed in this Handbook, you should become familiar with your particular state's SIP (including its NSR program) before commenting on or challenging a construction permit.

All construction permits issued under the NSR program must be incorporated into the refinery's "Title V" permit.[40]

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[36] Note again that the offsets are particular to each specific criteria pollutant for which the area is in non-attainment.

[37] *See* CAA § 182, 42 U.S.C. § 7511a.

[38] The reviewing authority may "tak[e] into account energy, environmental, and economic impacts and other costs." 40 C.F.R. § 51.166(b)(12).

[39] *See* 40 C.F.R. § 51.165(a)(1)(xiii).

[40] Again, for an excellent and detailed guide to participation in the Title V permitting process, *see* "The Proof is in the Permit," *supra* note 24, *available at* http://nsdi.epa.gov/oar/oaqps/permits/partic/proof1.pdf.

Finally, although not directly related to the NSR program, oil refineries are subject to a few other statutory and regulatory schemes that limit emissions and are worth mentioning:

First, as noted above, all newly constructed, modified, or reconstructed oil refineries are also subject to "New Source Performance Standards" ("NSPS"), which apply *uniformly* to such refineries. *See* 40 C.F.R. Part 60, Subparts J, GGG, and QQQ. Thus, all BACT and LAER (although determined on a case-by-case basis) must be at least as stringent as the NSPS requirements (which apply uniformly to all refineries). The EPA has explained: "Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT)." 72 Fed. Reg. 27178, 27179 (May 14, 2007).[41]

Second, oil refineries are subject to the National Emission Standards for Hazardous Air Pollutants ("NESHAPs"), which require "major source"[42] refineries to meet "maximum achievable control technology" ("MACT")[43] requirements for HAPs.[44]

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[41] At the time of publication of this Handbook, the EPA is proposing to overhaul the NSPS applicable to oil refineries. *See* Proposed Standards of Performance for Petroleum Refineries, 72 Fed. Reg. 27178 (May 14, 2007) (to be codified at 40 C.F.R. Part 60, subparts J and Ja), *available at* http://a257.g.akamaitech.net/7/257/2422/01jan20071800/edocket.access.gpo.gov/2007/pdf/E7-8547.pdf. The proposed rule includes provisions that would make it even harder for the public and federal and state regulators to track emissions. EPA's proposal would, for instance, "clarify" existing rules by eliminating important requirements for continuous monitoring of certain flaring devices, making it harder to obtain accurate emissions data during flaring events that are supposed to be minimized under recent EPA consent decrees. The proposed rule also includes provisions which do not require adequate monitoring and limitation of a number of dangerous pollutants, such as VOCs, PM, SO_2, CO, and NO_X. In addition, the proposed NSPS fail to place any limitations whatsoever on emissions of carbon dioxide (CO_2), a major contributor to global warming. The Environmental Integrity Project, together with the Sierra Club, has submitted comments to the proposed refinery NSPS, pointing out these deficiencies and suggesting alternatives. Those comments are available at http://www.environmentalintegrity.org/pub462.cfm.

[42] "Major sources" for the purposes of the HAPs – *unlike* "major sources" for NSR purposes – are those that emit at least 10 tpy of any one HAP or 25 tpy of any combination of HAPs. CAA § 112(a)(1), 42 U.S.C. § 7412(a)(1).

[43] The MACT standard is set forth in CAA § 112. Although the statute does not use the term "maximum achievable control technology," the standard is commonly referred to as "MACT." The MACT standard for HAPs represents: "the maximum degree of reduction in emissions of the [HAPs] … (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable … through application of measures, processes, methods, systems or techniques including, but not limited to, measures which – **(A)** reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications, **(B)** enclose systems or processes to eliminate emissions, **(C)** collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point, **(D)** are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h) of this section, or **(E)** are a combination of the above." CAA § 112(d)(2), 42 U.S.C. § 7412(d)(2).

See CAA § 112, 42 U.S.C. § 7412, and 40 C.F.R. Part 63, subpart CC. The full list of 189 HAPs can be found at CAA § 112(b)(1), 42 U.S.C. § 7412(b)(1), and the list of HAPs particular to oil refineries can be found at 40 C.F.R. Part 63, Appendix to subpart CC, Table 1. The EPA has stated:

> Petroleum refineries are major sources of HAP emissions. Individual refineries emit over 23 megagrams per year (Mg/yr) (25 tons per year (tpy)) of organic HAPs including benzene, toluene, ethyl benzene, and other HAPs. ... The range of adverse health effects include cancer and a number of other chronic health disorders (*e.g.*, aplastic anemia, pancytopenia, pernicious anemia, pulmonary (lung) structural changes) and a number of acute health disorders (*e.g.*, dyspnea (difficulty in breathing), upper respiratory tract irritation with cough, conjunctivitis, neurotoxic effects (*e.g.*, visual blurring, tremors, delirium, unconsciousness, coma, convulsions).

60 Fed. Reg. 43244, 43245 (Aug. 18, 1995). *See also*, 72 Fed. Reg. 50716, 50720 (Sept. 4, 2007). The NESHAPs apply to both "new" and "existing" "major source" refineries, although the MACT standard applies less stringently to "existing" sources.[45] A final point to keep in mind regarding MACT standards is that the MACT requirements applicable to industrial boilers (including those at oil refineries) is set forth at 40 C.F.R. Part 63, subpart DDDDD. However, subpart DDDDD (the "boilers rule") was vacated by the court in <u>Natural Resources Defense Council v. EPA</u>, 489 F.3d 1250 (D.C. Cir. 2007). Therefore, oil refinery boilers are currently subject to the "MACT hammer" provisions of CAA §§ 112(g) and/or (j), 42 U.S.C. §§ 7412(g) and/or (j), such that where no NESHAP for boilers is in effect, the Title V permit must contain "equivalent emission limitation[s] by permit." That is, the permit "shall contain" NESHAPs for boilers, determined by the permitting authority "on a case-by-case basis, to be equivalent to the limitation that would apply to such source if an emission standard had been promulgated…." CAA § 112(j)(5). Further, any refinery Title V permit which references subpart DDDDD should explicitly state that those requirements are required under the authority and mandate of CAA §§ 112(g) and/or (j), since subpart DDDDD itself has been vacated.

Third, all existing oil refineries in non-attainment areas – whether having undergone new modifications or not – must meet "reasonably available control technology" ("RACT") standards. The RACT determination seeks to identify, on a case-by-case basis, "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering

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[44] HAPs are pollutants "which present, or may present, through inhalation or other routes of exposure, a threat of adverse human health effects (including, but not limited to, substances which are known to be, or may reasonably be anticipated to be, carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic) or adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise…." CAA § 112(b)(2), 42 U.S.C. § 7412(b)(2).

[45] *See* CAA § 112(d)(2)-(3), 42 U.S.C. § 7412(d)(2)-(3).

technological and economic feasibility."[46] Regarding the "technological" and "economic feasibility" determinations, *see* 57 Fed. Reg. 18070, 18073-74 (1992).

B. The Permitting Process[47]

1. Background

Both PSD and NA NSR permits issued under the NSR program are commonly called "construction permits" because the major source of air pollution (for our purposes, the refinery) must apply for and obtain the permit(s) prior to beginning construction of the expansion (or new facility). Since the "delegated" and "approved" NSR programs are administered by the states, the construction permits are usually issued by the state environmental protection agencies ("permitting authorities").[48]

Before any refinery expansion is even a gleam in an oil company's eye, you should position yourself to know about any application and/or draft permit as soon as possible. Identify your permitting authority (again, this can be done at http://www.epa.gov/nsr/where.html). Contact the permitting authority and ask to be notified about any agency action regarding air permits, as well as the particular refineries and/or regions in which you are interested (some states keep a list of interested parties and send notifications). This should be done both in writing and by telephone. You should also periodically check the agency's website and/or call to ask if any applications have been received or draft permits issued for public comment, especially if the agency does not maintain a list of interested parties.[49] Also, learn how your permitting authority publishes notification of public comment periods. Permitting authorities must provide 30 days for public comment on draft construction permits,[50] which begins to run from the date of publication, and the method of publication varies (for example, publication might be by local newspaper, government publication, or internet).[51] Check these publication outlets regularly.[52] Also, EIP is currently building a continually updated database with

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[46] Robert A. Wyman, Jr., Dean M. Kato & Jeffrey S. Alexander, "Meeting Ambient Air Standards: Development of the State Implementation Plans," The Clean Air Act Handbook at 47 (Robert J. Martineau, Jr. & David P. Novello, eds., American Bar Association, 2nd ed. 2004) (emphasis added), *citing* 44 Fed. Reg. 53726 (1979).

[47] This recitation of the NSR permitting process provides a brief overview, and is drawn largely from "ABCs of NSR," *supra* note 26, which provides a more comprehensive description.

[48] In some cases, construction permits may be issued by local or Tribal authorities, or by the appropriate U.S. EPA Regional Office. You can find your permitting authority at http://www.epa.gov/nsr/where.html.

[49] It is important to maintain a good working relationship with the staff of your permitting authority, as they are in the best position to either facilitate or hinder your efforts to obtain information. Fostering an adversarial relationship, even in the face of adversity, does not help your cause.

[50] Some permitting authorities may also publish notification of an *application* for a construction permit.

[51] Also, local news outlets might run stories about possible refinery expansions even before an application is submitted (although this does not count as official "publication" of any "notice").

[52] In addition to checking the publications, it is a good idea to monitor the permitting authority's website and periodically call the agency to check on publication. However, the agency itself might not know of

information on all refinery expansions under consideration, which will be available via our website at www.environmentalintegrity.org. Thirty days is a short time to prepare and submit comments on a draft construction permit, and the sooner you know of a possible expansion, the sooner you can obtain the relevant documents (see below) and become familiar with the issues.

As soon as possible, make a calendar of key deadlines. The earliest point at which this can be started is usually publication of the notice of the draft permit, as that notice will contain the deadline for public comment on the draft permit and the deadline to request a public hearing (or contested case hearing[53]) or date of public hearing if one is already scheduled. Deadlines to keep in mind (discussed more fully below) include the following:

1) Deadline for public comment on the draft permit.

2) Deadline to request a public hearing and/or contested case hearing, or the date of public hearing if one is already scheduled.

3) Date of final permit issuance.

4) Deadline for filing an appeal of the final permit.

2. Steps in the Process

With that background in mind, the following are the steps involved in the drafting and issuance of construction permits, with points identified at which the public can be heard.

1) Refinery representatives meet with the permitting authority, perhaps for many months, before submitting a permit application.

2) The refinery submits a construction permit application to the permitting authority.

- If you know of the application, you should request a copy from the permitting authority, as well as any correspondence between the applicant

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publication until it receives the "tear sheet" from the *applicant*, so that there may well be a delay between the beginning of the comment period and notice of the running of the comment period being placed on the agency website. Therefore, you should also contact the *applicant* to find out when the notice is published, and/or to request that the applicant notify *you personally* when the notice is published (the notice will have an applicant contact name and phone number). As is the case when working with agencies, fostering a professional working relationship (and avoiding an overtly adversarial relationship) with the applicant will help facilitate such communication.

[53] While a "public hearing" is usually a relatively informal proceeding involving public comments being heard from a microphone (although this does become part of the administrative record for purposes of appeal), a contested case hearing is essentially a "court" proceeding (like a trial) in an administrative forum (that is, although the hearing is formal, involving exhibits and testimony, et cetera, it is before an agency rather than an actual court).

and the permitting authority regarding the application. You should also request a copy of the existing construction permit that is sought to be modified.[54] In addition, you should determine the attainment status of the area for each criteria pollutant,[55] obtain the relevant administrative regulations pertaining to air pollution,[56] and determine whether the refiner owns or operates other facilities in the state.[57]

- As soon as you become aware of a permit application upon which you wish to comment, you should ask your permitting authority to notify you of any final decisions on the permit application (although you should not exclusively rely on receiving such notification).

3) The permitting authority reviews the application and ultimately determines that the application is "administratively complete."

- If you are aware of the application, you can request a meeting with the permitting authority to discuss the application.

- If this is the first you heard of the application, then see item number 2, above.

4) The permitting authority issues a draft permit for public review.

- As described above, the permitting authority will send a notice of issuance of the draft permit to people on its list of interested parties, and the refinery will publish the notice.[58] The notice will tell you where you can find a copy of the draft permit, usually in the agency offices or on the

[54] The permitting authority might require you to submit a public records request (sometimes called a Freedom of Information Act ("FOIA") request) to obtain some or all of these documents. The permitting authority should be able to tell you how to do this (which is generally fairly simple). The documents might be hundreds of pages, and the agency will probably charge a copying fee. However, the state public records laws usually include a "fee waiver" provision which allows you to request a waiver of the fees under certain circumstances (*e.g.*, when the request is in the public interest). Alternatively, you can usually review the actual file in the agency offices and choose to copy only the portions of interest. Also, you might be able to obtain some or all of the documents on CD or DVD. If so, the permit drafter might be willing to send those documents to you by e-mail (there are no hard-and-fast rules here, and it does not hurt to ask).

[55] This information can be found at http://www.epa.gov/oar/oaqps/greenbk/.

[56] The permitting authority should provide this information. The regulations might be available on the agency's website, or, alternatively, can be found at http://www.findlaw.com/casecode/.

[57] The permitting authority should provide this information, or else it might be on the agency's website. The information is useful because if the other facilities are not in compliance with the CAA and have no plan to come into compliance, then the state cannot issue an NA NSR permit and, in some states, cannot issue a PSD permit. A useful resource in this regard is the U.S. EPA's online database, "Enforcement and Compliance History Online" ("ECHO"), available at http://www.epa.gov/Compliance/data/systems/multimedia/echo.html.

[58] The permitting authority might mail the notice before the refinery publishes it.

agency website. Also, the permitting authority might provide you with a copy of the draft permit on request.

- If you first learn of the refinery expansion from the draft permit notice, then you should obtain all of the documents listed above under "application," as well as the draft permit itself.

- ***Deadline!*** At this stage, you should review the draft permit and submit comments. The deadline for public comment on the draft permit will be in the draft permit notice, and will usually be 30 days (and must be at least 30 days) from the date of publication of the draft permit notice. Since you can only appeal the final permit on issues you raise in your comments on the draft permit, you must meet this deadline or most likely will never be heard on the permit.[59]

- ***Deadline!*** The deadline to request a public hearing and/or contested case hearing, or the date of public hearing if one is already scheduled, will also be in the draft permit notice, and will usually be 30 days from the date of publication of the draft permit notice. While both types of hearings become part of the administrative record for purposes of appeal, a "contested case hearing" is much more formal than a "public hearing," resembling a court trial, and you should consider hiring an attorney (or finding one to represent you for free) at a contested case hearing.

- You may request an extension of the public comment period, which the permitting authority may grant or deny at its discretion. It may be useful to partner with other commenters in requesting an extension.

- The substance of your comments, and the typical issues to look for and/or raise regarding refinery permits, is discussed in detail below.

5) The permitting authority considers and responds to all comments received, possibly revises the permit in response to some comments, and issues a final construction permit to the refinery.

    - The permitting authority should provide its Response to Comments ("RS") along with the final permit.

[59] As noted above, all construction permits issued under the NSR program must be incorporated into the refinery's "Title V" permit. Although this Handbook does not address Title V issues, it is worth noting, here, that the Title V permit has its own opportunities for public participation. Usually, the construction permit is issued before the Title V permit. However, although the federal regulations allow the refinery to wait a year after starting operations to apply for a Title V permit, some states require the Title V permit to be obtained before construction begins, and/or issue combined NSR/Title V permits. In such cases, you must keep in mind the comment deadlines for *both* the construction permit and the Title V permit and comment on them *separately*. The deadline for comments on both types of draft permits is generally 30 days.

- ***Deadline!*** You probably will not know the date of final permit issuance until the final permit is actually issued. However, it is important to watch for the final permit issuance, as you will have a very short time in which to review the final permit and file an appeal if necessary (perhaps as little as 20 days). Your permitting authority should notify you if you have asked to be notified of any final decisions on the permit application. However, you should not count on such notification.

- The average time between submission of a construction permit application and issuance of a final permit is about 7 months, although it can take anywhere from about 2 months to over 2 years.[60]

6) You can appeal the final permit.

   - An appeal of a final permit is litigation, and is a very lengthy and complicated process for which you should probably retain an attorney.

   - An appeal of a construction permit issued under a "delegated program" will be before the U.S. EPA's Environmental Appeals Board ("EAB"), whose decisions are appealed to the appropriate federal court. An appeal of a construction permit issued under an "approved program" will probably be before a state administrative law judge ("ALJ"), whose decisions will be appealable as specified in the approved program. In either case, you will be required to exhaust the administrative appeals process before bringing the case to court.

   - Again, you can only appeal the final permit on issues you raised in your comments on the draft permit.

   - Some states require that you have "standing" to challenge the final permit. While "standing" is a somewhat complicated legal concept, you essentially have to show that you are "harmed" by the pollution emitted from the new project. You might be harmed if you live, work, attend school, or recreate (swim, fish, hike, etc.) near the refinery, and thus either breathe more pollution and/or are forced to curtail such activities due to either actual pollution or a fear of the effects of pollution. This injury may be even greater if you suffer from a health condition, such as asthma, which can be aggravated by pollution. Also, if the refinery fails to provide information to the permitting authority that it has a duty to provide, you might suffer an "informational injury." In addition, if an organization has members who have been harmed by the project, the organization might have "organizational standing."

[60] U.S. EPA, "NSR 90-day Review Background Paper," June 22, 2001 (Docket No. A-2001-19; Document No. 11-A-01), at 7, *available at* http://www.epa.gov/NSR/documents/nsr-review.pdf.

- Construction cannot begin until a final decision is reached on your appeal.

7) ***Deadline!*** The refinery must begin construction within 18 months of the issuance of the construction permit (or within the deadline set by a one-time extension), or else must re-apply.

8) The Refinery must comply with the terms of the construction permit.

- The construction permit will contain requirements that the refinery monitor pollution emissions and report those emissions to the permitting authority. You can obtain copies of some or all of these reports, and bring a "citizen suit" against the refinery under the CAA if it violates its construction permit or other CAA requirements. *See* CAA § 304, 42 U.S.C. § 7604. Again, this is litigation for which you should probably retain an attorney.

II. REFINING 101 – A BRIEF INTRODUCTION TO HOW REFINERIES WORK

Before considering what to look for in a refinery permit, it is useful to discuss, in the smallest of nutshells, the major processes involved in oil refining and the technology and pollutants associated with them.[61]

Crude oil, also called petroleum, is the stuff that comes directly out of the ground and contains primarily hydrocarbons (molecules containing hydrogen and carbon atoms), which contain a great deal of energy.[62] The hydrocarbons vary in weight and structure depending on the number and arrangement of the atoms. Different types of hydrocarbons are used to make different products; for example, the hydrocarbons used to make gasoline for automobiles contain from 5 to 12 carbon atoms, while those used to make industrial fuel oil contain from 20 to 70 carbon atoms.[63]

An oil refinery first removes salts, suspended solids and metals from the crude oil (a process called "desalting"). Second, the refinery separates the hydrocarbons in the crude oil by boiling point (*i.e.*, into the oil's different "fractions") (called "fractional

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[61] For a more detailed discussion of refinery processes, *see* "OSHA Technical Manual (OTM)," TED 01-00-015 [TED 1-0.15A], U.S. Dept. of Labor, Occupational Safety & Health Administration, Sect. IV, chap. 2, parts III-IV, *available at* http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html#3 (*hereinafter* "OSHA Technical Manual"); EPA Refinery Sector Notebook, *supra* note 7, at 12-31, *available at* http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/petrefsnpt1.pdf; and EPA OIG Report, *supra* note 8, at Appendices C and D, *available at* http://www.epa.gov/oig/reports/2004/20040622-2004-P-00021.pdf.

[62] Crude oil contains the following approximate amounts of each constituent: carbon (84%), hydrogen (14%), sulfur (1-3%), and nitrogen, oxygen, metals, and salts (all less than 1%). Craig C. Freudenrich, "How Oil Refining Works" (Jan. 04, 2001), *available at* http://www.howstuffworks.com/oil-refining.htm/printable.

[63] *Id*.

distillation," "fractionation," or simply "distillation"). Third, the refinery breaks (or "cracks") the hydrocarbon molecules in order to produce different products such as gasoline, fuel oil, kerosene, or lubricating oil.[64] Other operations include wastewater treatment, sulfur recovery, "blowdown" system operation, flaring, and storage of the products in tanks.[65]

A. Desalting

Brine, salts, solids, and metals must be removed from the crude oil before fractionation in order to avoid corroding and fouling the equipment. This is done with heat and chemicals or a high-voltage electrical field. This process produces "an oily desalter sludge and a high temperature salt water waste stream."[66]

Air emissions from desalting include heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates) and fugitive emissions[67] (hydrocarbons).[68]

B. Fractional Distillation

Fractionation separates the hydrocarbons in the desalted crude oil by boiling point temperature. The oil is fed into a 120-foot vertical steel tower, called a "distillation column" or "fractionating tower," and is heated to 700 degrees Fahrenheit, causing most of the oil to vaporize. The vapor cools as it rises in the tower, condensing on "fractionation trays" inside the tower along the way. The trays are located at specific condensation temperatures. The heavier hydrocarbons (with relatively more carbon atoms) condense at higher temperatures (*i.e.*, lower in the column), and lighter hydrocarbons (with fewer carbon atoms) condense at lower temperatures (*i.e.*, higher in the column). The condensed liquids are then drawn off from the trays. Some

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[64] A refinery might also manipulate hydrocarbon molecules by joining or reshaping them (alkylation, isomerization, or catalytic reforming).

[65] This Handbook presents a brief overview of the major refinery processes. Processes not specifically described in this Handbook include hydrotreating and hydroprocessing; alkylation; isomerization; polymerization; catalytic reforming; solvent extraction; chemical treating and sweetening; dewaxing; propane deasphalting; additive production; asphalt production; hydrogen production; lubricant, wax, and grease manufacturing; gas treatment (other than sulfur recovery); steam generation; electric power; gas and air compressors; tanker (marine and truck) loading and unloading; turbines; pumps, piping and valves; heat exchanger cleaning; blending; and cooling towers. For a description of these processes, *see* EPA Refinery Sector Notebook, *supra* note 7, at 12-31; and OSHA Technical Manual, *supra* note 61, Sect. IV, Chap. II, Part IV and V.

[66] EPA Refinery Sector Notebook, *supra* note 7, at 13.

[67] "Stack emissions," as the name indicates, refer to emissions from "point source" stacks and vents. "Fugitive emissions" refer to leaks from valves, pumps, tanks, flanges, et cetera. The EPA has observed that "[w]hile individual leaks are typically small, the sum of all fugitive leaks [from the thousands of potential sources] at a refinery can be one of its largest emission sources." EPA Refinery Sector Notebook, *supra* note 7, at 32.

[68] EPA Refinery Sector Notebook, *supra* note 7, at 34, Exhibit 15.

hydrocarbons will result in “straight run” products needing no further processing, and others will undergo further processing, described below.

Two types of fractional distillation are used: “atmospheric distillation” and “vacuum distillation.” “Atmospheric distillation” is used first. The tower is maintained at atmospheric pressure and only heat is used to vaporize the oil. However, the heaviest crude may not vaporize at 700 degrees Fahrenheit (and greater temperatures would produce “thermal cracking,” described below, which is not desired at this stage). This heaviest oil is removed from the bottom of the atmospheric distillation tower and fed into a vacuum distillation tower, which is basically the same as an atmospheric distillation tower, except that it uses very low pressure to increase volatilization without increased heat. The fractions obtained through vacuum distillation will later be further broken down through “cracking,” described below.

Air emissions from atmospheric distillation include heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates), vents and fugitive emissions (hydrocarbons).[69]

Air emissions from vacuum distillation include steam ejector emissions (hydrocarbons), heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates), vents and fugitive emissions (hydrocarbons).[70]

C. Cracking

Basically, “cracking” breaks heavy hydrocarbons into smaller molecules in order to make more profitable products, such as gasoline. There are essentially two methods through which this is accomplished: “thermal cracking” and “catalytic cracking.” Today, thermal cracking (with the exception of “coking,” described below) has largely been replaced by catalytic cracking.

1. Thermal Cracking

Thermal cracking uses heat and sometimes pressure to break the hydrocarbon molecules. There are three types of thermal cracking: “steam cracking,” “visbreaking,” and “coking” (both “delayed coking” and “fluid coking”).

Steam cracking is not used to produce gasoline, but rather is a petrochemical process employing very hot steam (1,500 degrees Fahrenheit) and pressures slightly above atmospheric pressure to produce ethylene and benzene, which are used in chemical manufacturing.

Visbreaking uses heat (about 900 degrees Fahrenheit) at atmospheric pressure to crack hydrocarbons, thereby reducing the viscosity (hence the term “visbreaking”) of heavy weight oil.

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[69] *Id*.

[70] *Id*.

Air emissions from thermal cracking/visbreaking include heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates), vents and fugitive emissions (hydrocarbons).[71]

2. Coking

Although "coking" is technically a form of "thermal cracking," coking is addressed separately here due to the continued prevalence of coking, despite the virtual replacement of "thermal cracking" with catalytic cracking (and "fluid catalytic cracking units" ("FCCUs") in particular).

Coking units are intended to handle distillation bottoms and the heaviest petroleum fractions. Coking uses heat (1,000 degrees Fahrenheit) and pressure[72] to upgrade heavy crude to lighter, more profitable products such as gasoline. This process also produces "coke," which is solid carbon, nearly devoid of hydrogen. The coke may be sold for use as fuel in power plants, or as a raw material in the manufacture of carbon or graphic products, such as anodes for the production of aluminum.

There are two types of coking: "delayed coking" and "fluid coking." Delayed coking accounts for the lion's share of coking capacity in the refining industry.[73] In delayed coking, the heated oil is placed into "coke drums" and allowed to react for about 24 hours ("delayed") before being cooled. In "fluid coking" (sometimes called "continuous" or "contact" coking), the oil is placed in a "reactor," where higher temperatures than those used in delayed coking are reached. Vaporized hydrocarbons are taken from the reactor and fractionated, *and* coke is taken from the reactor and placed into a "surge drum." From the surge drum, large coke particles are removed (usually with high-pressure water) to be sold (a process called "coke cutting"), but small coke particles are recycled back to the reactor as feedstock.[74] Coking occurs in both the reactor and the surge drum, and the flow of coke and feedstock is "continuous."

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[71] *Id*.

[72] At high pressure, liquid can be heated in liquid form beyond the point at which it would otherwise vaporize at atmospheric pressure (its boiling point).

[73] From 2001 to 2006, on average, "fluid coking" accounted for only 8.4% of the refining industry's total coking charge capacity, and "delayed coking" accounted for the remaining 91.6% of capacity. *See* http://tonto.eia.doe.gov/dnav/pet/pet_pnp_capchg_dcu_nus_a.htm. Although the EPA speculated in 1995 that "'fluid coking' is expected to be an important process in the future" (EPA Refinery Sector Notebook, *supra* note 7, at 17), the EPA reported in 2007 that "there are at most [only] four fluid coking units in the United States that could potentially become subject to the [proposed NSPS] standard. Although coking capacity is expected to increase, most new units are expected to be delayed coking units." 72 Fed. Reg. 27178, 27191 (May 14, 2007). Thus, at the time of publication of this Handbook, "delayed coking" continues to account for the lion's share of coking capacity.

[74] "Feedstock" refers to any material, such as crude oil, which is being "fed" into the process to be refined.

Air emissions from coking include heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates), vents and fugitive emissions (hydrocarbons), and decoking emissions (hydrocarbons and particulates).[75]

Cokers can be particularly hazardous, as they require processing of very dirty residue from the catalytic cracking process under conditions of extreme pressure and heat. Citizens of Corpus Christi, Texas have complained of large black clouds of coke dust, and plant operators have complained of foul odors resulting from the use of wastewater in the "quenching" or cooling process. In commenting on a proposed refinery construction permit, you should ask that the coking operation be fully enclosed to prevent the dispersal of coke dust when coke is periodically removed from drums; that emissions of benzene and VOCs be monitored (*e.g.*, using portable analyzers); and that the permitting authority prohibit the use of wastewater in the quenching process. *See* Appendix B for a list of specific technologies that should be required for coking units.

3. Catalytic Cracking

Like thermal cracking, catalytic cracking (commonly called "cat cracking") uses heat and pressure to break heavy hydrocarbon molecules into lighter hydrocarbons in order to produce, primarily, gasoline. However, as the name indicates, catalytic cracking also uses a catalyst (a material that facilitates, but does not participate in, a chemical reaction) to break the hydrocarbons. This process uses less heat and pressure than does thermal cracking and produces more high-octane gasoline. For this reason, catalytic cracking "has largely replaced thermal cracking."[76] There are three types of catalytic cracking: "fixed-bed catalytic cracking" (sometimes called "Thermofor catalytic cracking" ("TCC"), "moving-bed catalytic cracking," and "fluidized-bed catalytic cracking" ("FCC") (sometimes simply called "fluid catalytic cracking"). FCC reactors are "by far the most common"[77] type of catalytic crackers, called "fluidized-bed catalytic cracking units" ("FCCUs").[78]

The EPA has stated that "**[c]atalytic cracking is one of the most significant sources of air pollutants at refineries.**"[79] For this reason, and since catalytic cracking "has largely replaced thermal cracking" and FCCUs are "by far the most common" type of cat crackers, you should pay special attention to FCCU requirements in construction permits. Air emissions from catalytic cracking include heater stack gas (CO, SO_x, NO_x,

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[75] EPA Refinery Sector Notebook, *supra* note 7, at 34, Exhibit 15.

[76] EPA Refinery Sector Notebook, *supra* note 7, at 18. It should be noted, however, that "cokers" (technically a form of thermal cracking) are still quite prevalent, and are a significant source of air pollution from refineries.

[77] *Id*.

[78] For a detailed description of these processes, *see* EPA Refinery Sector Notebook, *supra* note 7, at 18-19; and OSHA Technical Manual, *supra* note 61, at § IV.E-F (note that the OSHA manual incorrectly contains two sections "F").

[79] EPA Refinery Sector Notebook, *supra* note 7, at 19 (emphasis added).

hydrocarbons and particulates), fugitive emissions (hydrocarbons), and catalyst regeneration (CO, SO_x, NO_x, and particulates).[80]

Although cat crackers are major sources of SO_2 and NO_x, according to U.S. EPA emission factors, refineries are also significant sources of formaldehyde, a known human carcinogen. In commenting on a proposed refinery construction permit, you should ask what the formaldehyde emissions are, how the refinery monitors or estimates the formaldehyde emissions, and whether the refinery is reporting formaldehyde emissions. *See* Appendix B for a list of specific technologies that should be required for catalytic cracking units.

D. Catalytic Hydrocracking

Catalytic hydrocracking combines catalytic cracking with hydrogenation; that is, hydrocarbon molecules are subjected to catalytic cracking under very high pressure (1,000 – 2,000 pounds per square inch ("psi")) in the presence of hydrogen, which aids in cracking and increases gasoline production. The feedstock usually consists of oil fractions that are difficult to process with catalytic cracking because, for example, they contain a lot of sulfur and nitrogen, which poison catalysts. Hydrogenation converts the sulfur and nitrogen compounds to hydrogen sulfide and ammonia, which are sent to the sour gas[81] treatment and sulfur recovery systems.

Air emissions from catalytic hydrocracking include heater stack gas (CO, SO_x, NO_x, hydrocarbons and particulates), fugitive emissions (hydrocarbons), and catalyst regeneration (CO, SO_x, NO_x, and catalyst dust).[82]

E. Heaters and Boilers

Refineries use numerous process heaters ("furnaces") to heat the oil in the various processes to reaction temperatures, and boilers to generate steam for heating or stripping.

Air emissions from heaters and boilers include SO_x, NO_x, CO, H_2S, particulates, and hydrocarbons.[83]

The EPA has found that, historically, refineries have substantially underestimated their emissions of NO_x from heaters and boilers. New and existing heaters and boilers should be equipped with continuous emission monitors that measure emissions of NO_x

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[80] *Id*. at 34, Exhibit 15.

[81] "Sour gas" (also sometimes called "refinery gas," "still gas," or "acid gas") refers to "refinery process off-gas" (the mixture of gases produced as a result of fractionation, cracking, coking, hydrotreating, et cetera). This gas is composed mostly of methane and ethane, and usually also contains hydrogen sulfide and ammonia.

[82] EPA Refinery Sector Notebook, *supra* note 7, at 35, Exhibit 15.

[83] EPA Refinery Sector Notebook, *supra* note 7, at 32; and OSHA Technical Manual, *supra* note 61, at § V.A-B.

and other contaminants. *See* Appendix B for a list of specific technologies that should be required for heaters and boilers.

F. Wastewater Treatment

Oil refineries use a great deal of water and generate four basic types of wastewater: surface water runoff, cooling water, process water, and sanitary wastewater.

Surface water runoff contains contaminants from spills, leaks, drains, and runoff from storage tank roofs.

Cooling water is used repeatedly to cool machinery or product in cooling towers, and is stored in between use. Since it is not supposed to come into contact with oil, it does not contain as much contamination as water used directly in refinery processes. However, cooling water does usually contain chemical additives to prevent biological growth or other fouling of pipes, as well as some oil due to leaks.

Process wastewater accounts for a great deal of refinery wastewater, and because it comes into direct contact with oil, it is highly contaminated. This wastewater is a byproduct of processes such as desalting, steam stripping, pump gland cooling, fractionator drainage, and boiler and cooling tower blowdown.[84]

Refineries generally use both primary and secondary wastewater treatment methods, but the wastewaster can usually be sent to a publicly owned treatment works ("POTW") after primary treatment, or undergo secondary treatment and then be discharged into surface waters (such as rivers or lakes[85]) pursuant to a National Pollution Discharge Elimination System ("NPDES") permit under the Clean Water Act.[86]

Although the wastewater generated by a refinery and the refinery's wastewater treatment plant are obviously relevant to the refinery's generation of water pollution,[87] the EPA has observed that refinery "[w]astewater treatment plants are a significant source of refinery *air* emissions … [which] arise from fugitive emissions from the numerous tanks, ponds and sewer system drains."[88] The wastewater from the blowdown systems

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[84] "Boiler blowdown" and "cooling tower blowdown" refer to the practice of discharging boiler water (or cooling water) and replacing it with fresh water in order to avoid and control excessive buildup of total dissolved solids which would increase boiler scaling and deposits on cooling tower surfaces, and increase particulate emissions from cooling towers.

[85] For example, at the time of publication of this Handbook, British Petroleum ("BP") has generated something of a political firestorm by obtaining a Clean Water Act permit to increase its dumping of pollution into Lake Michigan as part of it's planned $3 billion expansion of its massive Whiting, Indiana refinery to process Canadian "tar sands."

[86] For a description of the treatment processes, *see* EPA Refinery Sector Notebook, *supra* note 7, at 25-27; and OSHA Technical Manual, *supra* note 61, at § V.D.

[87] As previously noted, this Handbook does not address water permits.

[88] EPA Refinery Sector Notebook, *supra* note 7, at 27 (emphasis added).

"is typically composed of mixtures of water and hydrocarbons containing sulfides, ammonia, and other contaminants…."[89] Cooling towers are significant sources of VOCs because petroleum liquids are transferred to cooling water through leaks, and some refineries use cooling towers for air stripping of VOCs from process wastewater. Air emissions from wastewater treatment are composed of fugitive emissions (hydrogen sulfide (H_2S), ammonia (NH_3), benzene (C_6H_6), and hydrocarbons).[90]

Refinery wastewater treatment systems are a major source of benzene air emissions, because benzene (a known carcinogen) is a VOC that evaporates fairly easily. EPA investigations have found that refineries consistently underestimate the amount of benzene in their wastewater, which leads to artificially low emission estimates that are used to claim exemption from Clean Air Act control requirements that would otherwise apply. In commenting on a proposed refinery construction permit, you should ask that the permit specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions. *See* Appendix B for a list of specific technologies that should be required for wastewater treatment systems.

G. Sulfur Recovery

In order to meet SO_x emission limits set by the Clean Air Act, refinery "sour gas" (also sometimes called "refinery gas," "still gas," "acid gas," or "process off-gas" resulting from fractionation, cracking, coking, hydrotreating, and hydroprocessing)[91] must be treated to remove sulfur, which can also be sold. First, the hydrogen sulfide (H_2S) is removed from the sour gas with a chemical solvent. Second, the gas is returned for use as fuel in refinery processes, and elemental sulfur is removed from the hydrogen sulfide using (primarily) the "Claus Process," which utilizes heat and a catalyst.[92] The sulfur recovery apparatus is commonly called the "Claus Unit," "Sulfur Recovery Unit" ("SRU"), or "Sulfur Recovery Plant" ("SRP"). The gas from the SRU is referred to as "tail gas." Some refineries use incinerators for treating such tail gas, others use the Shell Claus Offgas Treatment ("SCOT") system, and still others use a solution tank treatment known as a Stretford process.

Air emissions from gas treatment and sulfur recovery include tail gas, vent, and fugitive emissions (SO_x, NO_x, and H_2S).[93] Fugitive emissions of H_2S also come from the sulfur recovery pits used to store the recovered sulfur.[94]

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[89] *Id*. at 30.

[90] *Id*. at 36, Exhibit 15.

[91] This gas is composed mostly of methane and ethane, and usually also contains hydrogen sulfide and ammonia.

[92] For a detailed description of gas treatment and sulfur recovery, *see* EPA Refinery Sector Notebook, *supra* note 7, at 28. *See also*, 72 Fed. Reg. 27178, 27187-88 (May 14, 2007).

[93] EPA Refinery Sector Notebook, *supra* note 7, at 28-29, 32, and 36, Exhibit 15.

[94] 72 Fed. Reg. 27178, 27187 (May 14, 2007).

SRUs need to expand to keep pace with increases in the production capacity of cat crackers and other units at the front end of refineries, or else the refinery will be overwhelmed with sulfur-rich waste streams that end up being released to the environment. Therefore, SRUs should have some "redundant" capacity to handle sudden spikes in the sulfur content of waste streams.

H. Flare System

The flare system handles excess gases that must be vented when pressure in any process or equipment becomes dangerously high. A "flare" (large open flame) at the top of a stack burns off gases (hydrocarbons and acid gases) that are not permitted to be discharged directly into the air. "Flaring" should not be used on a routine basis, but only as a last resort in unusual circumstances such as emergencies.

Air emissions from blowdown systems[95] include primarily SO_x when flared. Air emissions from flares also include CO and NO_x.[96]

Studies have shown that wind and other factors can reduce flare combustion efficiencies, which means that, although refineries typically estimate flare efficiency at 98-99%, more pollution is actually being released into the environment than estimated, rather than being destroyed during combustion.[97] In commenting on a proposed refinery construction permit, you should ask how emissions from flares are estimated, and insist that any emissions be promptly reported (*see* discussion of "upsets," below). *See* Appendix B for a list of specific technologies that should be required for flare systems.

I. Leak Detection and Repair (LDAR)

"Fugitive emissions" are leaks from valves, pumps, storage tanks, flanges, et cetera. The EPA has observed that "[w]hile individual leaks are typically small, the sum of all fugitive leaks [from the thousands of potential sources] at a refinery can be one of its largest emission sources."[98] A "leak detection and repair" ("LDAR") program typically uses a portable VOC detection device to check for hydrocarbon leaks. An LDAR program may be either "directed" (follow-up testing is done to make sure that the

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[95] "Blowdown systems" "provide for the safe handling and disposal of liquid and gases that are either automatically vented from the process units through pressure relief valves, or that are manually drawn from units." EPA Refinery Sector Notebook, *supra* note 7, at 30.

[96] *Id*. at 30, and 36, Exhibit 15.

[97] *See, e.g.*, "Reducing Flare Emissions from Chemical Plants and Refineries – An Analysis of Industrial Flares' Contribution to the Gulf Coast Region's Air Pollution Problem," Industry Professionals for Clean Air ("IPCA"), May 23, 2005, *available at* http://www.ipcahouston.org/files/IPCA_Flare_Report2005.pdf; and Robert E. Levy, Lucy Randel, Meg Healy and Don Weaver, "Reducing Emissions from Flares – Paper # 61," Industry Professionals for Clean Air ("IPCA"), April 24, 2006, *available at* http://www.ipcahouston.org/files/IPCA_Flare_AWMA2006.pdf.

[98] EPA Refinery Sector Notebook, *supra* note 7, at 32.

leak is fixed) or "non-directed" (no follow-up testing is done).[99] An effective LDAR program should reduce fugitive emissions by over 60%.[100]

Fugitive air emissions detected by LDAR programs include VOCs (hydrocarbons).[101]

Fugitive emissions are often chronically underestimated because they are so infrequently and poorly monitored. In commenting on a proposed refinery construction permit, you should insist that the permit require state of the art monitoring for such emissions by, for example, requiring the use of "Fourier Transformation Infrared Spectroscopy" ("FTIR") (discussed below). *See* Appendix B for a list of specific technologies that should be required to control fugitive emissions.

J. Storage Tanks

Storage tanks are used throughout refineries for storage of crude oil, intermediate feedstock, and finished products, as well as storage of water, acids, additives, and other chemicals.

The EPA has stated that "[e]ven if equipped with floating tops, storage tanks account for considerable VOC emissions at petroleum refineries," and that air emissions from storage tanks include fugitive emissions of hydrocarbons.[102]

A failure to properly control emissions from storage tanks is a serious matter. For example, Citgo Petroleum Corporation was convicted on June 27, 2007 on two felony violations of the Clean Air Act for operating storage tanks at its Corpus Christi, Texas refinery without fixed or floating roofs, such that the company faces fines up to $500,000 per count or twice the economic gain (whichever is higher), and five years of probation.[103]

See Appendix B for a list of specific technologies that should be required for storage tanks.

III. KEY ISSUES IN CONSTRUCTION ("NSR") REFINERY PERMITS

With a background knowledge of NSR law and the basics of refinery operations, you are now ready to consider the key issues involved in commenting on NSR

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[99] "ABCs of NSR," *supra* note 26, at 87, *citing* Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" (Jan. 26, 2003).

[100] EPA Refinery Sector Notebook, *supra* note 7, at 62 (citation omitted).

[101] *Id*. at 61.

[102] *Id*. at 31, and 36, Exhibit 15.

[103] *See* U.S. Department of Justice news release, "Citgo Petroleum and Subsidiary Found Guilty of Environmental Crimes," June 27, 2007, *available at* http://www.usdoj.gov/opa/pr/2007/June/07_enrd_463.html.

construction permits. The first subsection, below, will review issues common to both PSD (attainment area) and NA NSR (non-attainment area) permits. The second subsection will address issues particular to PSD permits, and the third subsection will consider NA NSR-specific issues. Finally, the fourth subsection will list specific technologies that you should request when commenting on NSR program permits for oil refineries.

A. Issues Pertaining to both PSD and NA NSR Construction Permits

1. Emissions increases and NSR applicability

As noted above, oil refineries are considered "major stationary sources" if they emit 100 tons per year ("tpy") or more of any criteria pollutant. In practice, however, every existing oil refinery in the United States (and any potential "new" refinery) almost certainly qualifies as a "major stationary source," so the real question is whether a "modification" (*i.e.*, "expansion") is "major." A modification is considered "major" if the "net increase" in actual or potential emissions meets *any* of the "significance" thresholds for the various pollutants listed at 40 C.F.R. § 51.166(b)(23)(i).[104] Those thresholds are as follow:

"Significant" Emission Rate Increases for "Major Modifications" at Oil Refineries

(*See also*, Appendix C to this Handbook)

Carbon monoxide:	100 tons per year ("tpy")
Nitrogen oxides:	40 tpy
Sulfur dioxide:	40 tpy
Particulate matter:	25 tpy of particulate matter emissions; 15 tpy of PM_{10} emissions
Ozone:	40 tpy of volatile organic compounds or NO_X
Lead:	0.6 tpy
Fluorides:	3 tpy
Sulfuric acid mist:	7 tpy

[104] Also, you should keep in mind that, no matter what the "net increase," a refinery expansion is also considered "major" if it occurs within 10 kilometers of a "Class I area" (such as certain Wilderness Areas, National Wildlife Refuges, National Parks, et cetera) and the increased emissions would increase the 24-hour average ambient air concentration of a regulated pollutant in the Class I area by at least one microgram per cubic meter (1 $\mu g/m^3$). 40 C.F.R. § 52.21(b)(23)(iii). For a list of "Mandatory Class I Areas," *see* EPA NSR Workshop Manual, *supra* note 35, at E.3 – E.6, reproduced as Appendix I to this Handbook.

Hydrogen sulfide (H_2S):	10 tpy
Total reduced sulfur (including H_2S):	10 tpy
Reduced sulfur compounds (including H_2S):	10 tpy

For example, if the expansion will result in a net emission increase of 10 tpy of hydrogen sulfide (H_2S), then the increase is "significant" and the modification is "major" and the expansion requires an NSR permit.

In addition to determining NSR applicability, it is important to ensure that the permitting authority has correctly calculated the emissions increases because: 1) if the permit is a PSD (attainment area) permit, then the net increase cannot exceed the "increment" for any criteria pollutant; 2) if the permit is an NA NSR (non-attainment) permit, then offsets must be obtained for the increases; and 3) if the facility has claimed to have "netted out" of NSR applicability (*see* discussion of "Significant Net Emissions Increase, a.k.a. 'Netting,'" below), then you should make sure that those calculations are correct and take into account all relevant emissions.

Facilities will do almost anything to avoid New Source Review, by either claiming that they have not had a "major" modification, or that they are "netting out" of emission increases. The latter is more likely where large projects are involved, although you should also watch for "sham minor modifications" which attempt to split major modifications into multiple "minor" modifications. The problem of refineries attempting to avoid NSR altogether by "splitting" or "netting" is one of the most important issues to watch for when reviewing a proposed permit. Both issues are addressed more fully below.

The story of how to calculate net emissions increases is inextricably intertwined with how to determine whether a modification triggers the NSR program; that is, whether the modification is a "major modification." The EPA defines a "major modification" as "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase … of a regulated NSR pollutant …; *and* a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 51.166(b)(2)(i) (emphasis added). Therefore, in order for a modification to be "major," it must: 1) occur at a "major stationary source;" 2) be a "physical change in or change in the method of operation;" 3) result in "a significant emissions increase;" and 4) also result in "a significant *net* emissions increase;" 5) of a "regulated NSR pollutant."

a. “Major Stationary Source” and “Regulated NSR Pollutants”

As noted above, all existing oil refineries (and any potential new ones) almost certainly qualify as “major stationary sources” (emitting at least 100 tpy of an NSR “regulated pollutant,” which includes the “criteria pollutants,” VOCs, and total PM. *See* 40 C.F.R. § 51.166(b)(49)).

b. Physical or Operational Change

A “physical change in or change in the method of operation” (or, more succinctly, a “physical or operational change”) is not clearly defined in the regulations. However, the regulations do identify a few things that are *not* “physical or operational changes,” including the use of certain alternative fuels, increasing hours of operation or production rate if not prohibited by a permit condition, change in ownership, and “[r]outine maintenance, repair and replacement” (“RMRR”).[105] 40 C.F.R. 51.166(b)(2)(iii). Any other type of “modification” is arguably a “physical or operational change” for purposes of determining whether a project is a “major modification.”

c. Significant Emissions Increase

In order to determine whether an “increase” (as opposed, for the moment, to a “net increase”) is “significant,” it is necessary to: 1) determine present (pre-modification) emissions; 2) determine future (post-modification) emissions; 3) calculate the difference; and 4) compare the increase to the “significance” thresholds found at 40 C.F.R. § 51.166(b)(23)(i).[106] That is, the basic idea (if not the regulatory implementation) is quite simple: future pollution – present pollution = increased pollution. Note that this exercise (and the calculation of the “net” increase, discussed below) must be done for each individual regulated pollutant[107] that will be emitted. The

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[105] In 2003, the EPA issued a rule that defined RMRR, in part, as including the replacement of “components” of “process units,” where the cost of replacing the “component(s)” does not exceed 20% of the cost of replacing the entire “process unit.” *See* 68 Fed. Reg. 61,248 (Oct. 27, 2003); 40 C.F.R. § 51.166(y). However, that rule was challenged by numerous states and environmental organizations, and was “stayed” by the U.S. Court of Appeals for the District of Columbia Circuit. *See* New York v. U.S. EPA, No. 03-1380 (D.C. Cir., Dec. 24, 2003). A “note” in the current (revised July 1, 2006) Code of Federal Regulations to 40 C.F.R. § 51.166(b)(2)(iii)(*a*) (definition of “[r]outine maintenance, repair and replacement”) states: “On December 24, 2003, the second sentence of this paragraph (b)(2)(iii)(*a*) is stayed indefinitely by court order. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the FEDERAL REGISTER advising the public of the termination of the stay.” However, the stay was not terminated, but rather the “RMRR rule” was *vacated* by the court in New York v. U.S. EPA, 443 F.3d 880 (D.C. Cir. 2006). That is, **the rule no longer exists**, despite its current appearance in the C.F.R. RMRR determinations are currently made on a case-by-case basis.

[106] Keep in mind that intentionally splitting what is in reality a single modification project into smaller projects in order to avoid triggering the NSR program by artificially characterizing total emissions increases as less than “significant” (“sham” minors) is illegal. EPA NSR Workshop Manual, *supra* note 35, at A-36 to A-37.

[107] *See* 40 C.F.R. § 51.166(b)(49) (“regulated pollutants”).

pollutants have different significance thresholds,[108] and NSR will be triggered and a construction permit required if even one of those pollutants meets its threshold.

The present (pre-modification) emissions are called the "baseline" emissions. These must be determined for each regulated pollutant at each "emissions unit" which is to be constructed or modified, and then summed to obtain the total "major source" baseline.[109]

Under the federal rules, if the modifications will be done to an existing unit, then the baseline emissions are the average rate at which the unit actually emitted each pollutant during "any consecutive 24-month period … within the 10-year period immediately preceding" the earlier of either the date that the construction begins or the date that the application was received by the permitting authority.[110] 50 C.F.R. § 51.166(b)(47)(ii). The facility owner may select the 2-year period, and the average rate may include fugitive emissions "to the extent quantifiable," but the average rate cannot include any emissions during the 2-year period which either exceeded then-applicable limits, or which would have exceeded currently applicable limits if those limits had been applicable during the 2-year period. *Id*. (This rule is perhaps easier to understand if you consider the rationale: as noted above, it is in the interest of the refinery that the baseline be as high as possible, so that the increase is as low as possible; thus, the refinery cannot count as "baseline" emissions those emissions which illegally exceeded its permit limits). Further, although the same 2-year period must be selected for all units being modified, a different 2-year period may be selected for each pollutant. Finally, the baseline cannot be based on any 2-year period for which records are inadequate. *Id*.[111]

If the modification consists of building a new emissions unit, then the formula for determining the baseline emissions is mercifully simple: since the unit has no history, the baseline is zero. 50 C.F.R. § 51.166(b)(47)(iii).

The future (post-modification) emissions may be determined in either of two ways, at the choice of the facility owner: either by "potential to emit" ("PTE"), or by "projected actual emissions."[112] 50 C.F.R. § 51.166(b)(40)(ii)(*d*). In either case, the

[108] For example, the significance threshold for carbon monoxide is 100 tpy, but the threshold for lead is only 0.6 tpy. 40 C.F.R. § 51.166(b)(23)(i). *See also*, Appendix C to this Handbook.

[109] Perhaps counter-intuitively, it is in the refinery's interest that the "baseline" be as *high* as possible. This is because the smaller the *difference* between the baseline and the future emissions, the smaller the increased emissions will be (and therefore, the fewer the required offsets, the easier the netting, and/or the less likely will be a PSD increment violation).

[110] The 10-year period provision applies to all major sources, including refineries, which are not "electric utility steam generating units" ("EUSGUs"), which must select a 2-year period within the preceding 5 years. 50 C.F.R. § 51.166(b)(47)(i).

[111] The baseline period used by your permitting authority will depend on whether it has adopted the federal rule or not.

[112] Although EPA rules allow refineries to estimate future emissions based on "projected actual" emissions, some states have not accepted that rule, and still base emissions increases on "potential to emit" ("PTE").

future emissions will be the sum of future emissions from all of the emissions units (for each regulated pollutant) in the major source that are part of the modification. Here, of course, it is in the refinery's interest that the future emissions be as *low* as possible.

"Potential to emit" is defined as "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design." 50 C.F.R. § 51.166(b)(4). There are two fundamental parameters embodied in this definition: at one end of the spectrum, PTE considers the "maximum" capacity; at the other end, PTE considers "physical and operational" limitations on that maximum capacity. "Maximum capacity" means that the facility is assumed to be operating at full tilt, 24 hours a day, 365 days a year.[113] The EPA has described this parameter as:

> … the worst case uncontrolled emissions rate, which is based on the dirtiest fuels, and/or the highest emitting materials and operating conditions that the source is or will be permitted to use under federally-enforceable requirements.[114]

In addition, "fugitive emissions" should be included in the PTE for refineries (since refineries are a named PSD source category subject to the 100 tpy major source threshold in 40 C.F.R. § 51.166(b)(1)(i)(*a*)),[115] as well as emissions from "start-up, shut-down, and maintenance" ("SSM") activities.[116] "Physical and operational limitations" include "air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed,"[117] but those limitations must be "federally enforceable," as defined at 40 C.F.R. § 51.166(b)(17).[118] Note, however, the EPA's observation that "[a] requirement may purport to be federally enforceable, but in reality cannot be federally enforceable if it cannot be enforced as a practical matter,"[119] and EPA's further explanation that:

> For any limit or condition to be a legitimate restriction on potential to emit, that limit or condition must be federally-enforceable, which in turn requires ***practical enforceability***…. Practical enforceability means the source and/or enforcement authority must be able to show ***continual*** compliance (or noncompliance) with each limitation or requirement. In

[113] *See* EPA NSR Workshop Manual, *supra* note 35, App. C.

[114] *Id*. at A.19.

[115] *Id*. at A.9 – A.10.

[116] *See* "ABCs of NSR," *supra* note 26, at 72.

[117] 40 C.F.R. § 51.166(b)(4).

[118] *Id*. Where the PTE would otherwise meet the "significance" thresholds and trigger NSR, but the source accepts *enforceable* physical and/or operational limitations which prevent the PTE from meeting the "significance" thresholds, thus avoiding NSR review, the modification is said to be a "synthetic minor" modification. Similarly, a source that would otherwise meet the 100 typ or 250 tpy "major source" thresholds, but avoids triggering NSR by accepting such limitations, is called a "synthetic minor" source.

[119] EPA NSR Workshop Manual, *supra* note 35, App. C at C-3.

> other words, ***adequate testing, monitoring, and record-keeping*** procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or the permit issued under same. For example, a permit that limits actual source emissions on an annual basis only (*e.g.*, the facility is limited solely to 249 tpy) cannot be considered in determining potential to emit. It contains none of the basic requirements and is therefore not capable of ensuring continual compliance, *i.e.*, it is not enforceable as a practical matter.

EPA NSR Workshop Manual, *supra* note 35, at A.5 (emphases added) (citations omitted). EPA further states that "short-term averaging times on limitations are essential" for practical enforceability. *Id*. at App. C, C.3.

"Projected actual emissions" are "the maximum annual rate … at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) [or, in some cases, 10 years] following the date the unit resumes regular operation after the [expansion/modification] project [is completed]." 40 C.F.R. § 51.166(b)(40)(i). In order to determine these emissions, the facility owner "[s]hall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan." 40 C.F.R. § 51.166(b)(40)(ii)(*a*). In addition, the "projected actual emissions" must include fugitive and SSM emissions. 40 C.F.R. § 51.166(b)(40)(ii)(*b*).

Note that intentionally splitting what is in reality a single modification project into smaller projects ("sham" minor modifications) in order to avoid triggering the NSR program by artificially characterizing total emissions increases as less than "significant" is illegal. Where the projects are proposed within a short time, and the changes could be considered part of a single project, such an illegal "splitting" may have occurred.[120] Whether "minor modification" claims are simply in error, or are outright attempts to evade major modification review, you should watch for majors in minor clothing.

Another important point to keep in mind when reviewing whether a "major modification" has occurred is that states are no longer allowed to let industry substantially increase one pollutant (carbon monoxide, for example) in an effort to control another pollutant (such as nitrogen oxide); that is, there is no longer a "pollution control" exception (sometimes called a "pollution exclusion"), as EPA attempted to promulgate in 2002. As the U.S. Court of Appeals for the District of Columbia Circuit held in 2005:

> In an effort to remove a "regulatory disincentive that might otherwise prevent industry from undertaking pollution control and prevention measures," the 2002 rule exempts "environmentally beneficial" pollution

[120] EPA NSR Workshop Manual, *supra* note 35, at A.36 – A.37.

> control projects (“PCPs”) from NSR by excluding them from the definition of “modification.” Under the 2002 rule, a PCP that reduces emissions of a “primary” pollutant but increases emissions of a “collateral” pollutant is not a physical or operational “change” subject to NSR if its net effect is “environmentally beneficial.” … Environmental petitioners contend that these exemptions violate the language of the CAA because PCPs plainly are physical or operational “changes” that increase emissions of collateral pollutants. EPA concedes that PCPs are “changes” in the literal sense but contends that “Congress did not intend that PCPs be considered the type of activity that should trigger NSR.” Because EPA fails to present evidence of such congressional intent, the plain meaning of the statute is conclusive. … Therefore, we hold that EPA lacks authority to create PCP exemptions from NSR, and we vacate those parts of the 1992 and 2002 rules, 57 Fed.Reg. at 32,336, 67 Fed.Reg. at 80,275-76, 80,283-94 (codified at 40 C.R.F. §§ 52,21(b)(iii)(h), 52.21(b)(32, 52.21(z)), as contrary to the statute.[121]

So, once we have the “before and after” emissions picture, we can calculate the difference and compare the increase to the “significance” thresholds found at 40 C.F.R. § 51.166(b)(23). If no regulated pollutant increase meets or exceeds the “significance” thresholds, then that is the end of the story and no NSR permit is required.[122] However, assuming that the “raw”[123] increase does exceed the significance threshold, then there is a further step in determining whether the modification triggers NSR: the modification must result in a “significant *net* emissions increase.”

d. Significant *Net* Emissions Increase (a.k.a., “Netting”)

As the NSR regulations explain:

> [A] project is a major modification … if it causes two types of emissions increases – a significant emissions increase …, and a significant net emissions increase…. The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

[121] New York v. U.S. EPA, 413 F.3d 3, 40 (D.C. Cir. 2005) (citations omitted).

[122] If the “raw” emissions increase does *not* exceed the “significance” thresholds, then no NSR permit is required. Of course, if that had been the case, you would probably not be reviewing a draft or proposed NSR construction permit. However, remember that the emissions increase calculation is at the heart of the NSR program, and even though the determination has probably already been made that NSR applies, the higher the increased emissions, the more the required offsets and/or harder the netting and/or more likely is a PSD increment violation. So, even if the NSR “applicability” determination has already been made, it is still important to make sure that the permit takes into consideration the true total increased emissions.

[123] “Raw emissions increase” is not a term of art. This Handbook uses the term “raw” to distinguish the “emissions increase” from the “*net* emissions increase,” discussed below.

40 C.F.R. § 51.166(a)(7)(iv)(*a*). Thus, even if the "raw" emissions increase meets the "significance" thresholds of 40 C.F.R. § 51.166(b)(23), the facility could still avoid triggering the NSR program if the "net increase" does not meet the "significance" thresholds. The analysis to determine the "net increase" is called "emissions netting," and avoiding an NSR permit in this way is called "netting out."[124]

"Netting" to avoid NSR is currently perhaps the biggest loophole for oil refineries. As you read the following discussion (and review proposed permits), you should keep in mind the following points (discussed in more detail below):

1) The refinery should not get credit for any reductions it made in the past (or is making simultaneously) that were made because they were required by rules or consent decrees. Further, any voluntary reductions the facility made or plans to make have to be made enforceable.

2) You should question how any emission reductions from netting are going to be monitored and enforced. For example, if a refinery is claiming reductions from reducing fugitives (*e.g.*, through better leak detection), your comments should point out that these emission reductions are very hard to monitor and enforce and demand excellent monitoring for any fugitives that are claimed as netting credits (such as "Fourier Transformation Infrared Spectroscopy" ("FTIR"), discussed below).

3) Although EPA rules allow refineries to estimate future emissions based on "projected actual" emissions, some states have not accepted that rule, and still base emissions increases on "potential to emit" ("PTE"). You should insist that the refinery be enforceably limited to its projected actual emission increases, if your state SIP allows it.

The "net emissions increase" is the "raw" emissions increase from the modification (discussed above) minus any recent source-wide decreases in emissions, plus other recent source-wide increases in emissions.[125] Note that although the "raw" emissions increase pertains only to the modified or expanded portion of the refinery, the recent decreases or increases for netting purposes may come from any part of the refinery (although emissions reductions cannot be transferred between refineries for netting purposes).[126] Also, if a facility claims recent decreases for netting, it must also consider all recent increases.[127] Most importantly, the recent decreases and increases must be

[124] "Netting" is only available to "major sources." "Minor sources" may not net emissions because, as noted above, modifications to minor sources require construction permits only if the modifications themselves constitute a "major source" (*i.e.*, for refineries, result in a net increase of 100 tpy of any criteria pollutant); that is, such "modifications" are treated as newly constructed sources. As such, there are no past emissions to be netted. However, again, all existing refineries almost certainly qualify as "major stationary sources."

[125] 40 C.F.R. § 51.166(b)(3)(i).

[126] EPA NSR Workshop Manual, *supra* note 35, at A.35.

[127] *Id*. at A-36.

"contemporaneous" and "creditable" (and must be "federally and practically enforceable" to be "creditable").[128]

The EPA's "NSR Workshop Manual," *supra* note 35, states that, to be "contemporaneous," "[t]he changes must … occur within a period beginning 5 years before the date construction is expected to commence on the proposed modification … and ending when the emissions increase from the modification occurs."[129] However, the current NSR regulations state that "[a]n increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within a reasonable period (to be *specified by the state*) before the date that the increase from the particular change occurs."[130] Most states define "contemporaneous" as the 5 years preceding the modification, but you should check your state SIP.

To be "creditable," the recent decrease (or increase) must not have been previously relied upon by the permitting authority in issuing an NA NSR or PSD permit to the facility. As the EPA has explained:

> A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment [for a PSD permit] or ambient standard [("NAAQS") for an NA NSR permit]. In other words, an emissions change … which was considered in the issuance of a previous PSD permit for the source is <u>not</u> included in the source's "net emissions increase" calculation. This is done to avoid "double counting" of emissions changes.

EPA NSR Workshop Manual, *supra* note 35, at A.40 (emphasis in original). Further, a decrease is "creditable" only if it is "federally enforceable,"[131] as defined at 40 C.F.R. § 51.166(b)(17), *and* "enforceable *as a practical matter* at and after the time that actual construction on the [modification] begins."[132] Note that the decrease must have already occurred *before* the modification begins (that is, the facility cannot rely on future planned

[128] 40 C.F.R. §§ 51.166(b)(3)(i)(b), (vi)(*b*).

[129] EPA NSR Workshop Manual, *supra* note 35, at A.37 - A.38.

[130] 40 C.F.R. § 51.166(b)(3)(ii) (emphasis added).

[131] EPA NSR Workshop Manual, *supra* note 35, at A.38.

[132] 40 C.F.R. § 51.166(b)(3)(vi)(*b*) (emphasis added). As the EPA has observed, "[a] requirement may purport to be federally enforceable, but in reality cannot be federally enforceable if it cannot be enforced as a practical matter." EPA NSR Workshop Manual, *supra* note 35, App. C at C.3. Again, the EPA has explained that "[p]ractical enforceability means the source and/or enforcement authority must be able to show <u>***continual***</u> compliance (or noncompliance) with each limitation or requirement. In other words, <u>***adequate testing, monitoring, and record-keeping***</u> procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or the permit issued under same. For example, a permit that limits actual source emissions on an annual basis only … [is] not capable of ensuring continual compliance, *i.e.*, it is not enforceable as a practical matter." EPA NSR Workshop Manual, *supra* note 35, at A.5 (emphases added) (citations omitted). "[S]hort-term averaging times on limitations are essential" for practical enforceability. *Id*. at App. C, C.3.

decreases), and that the decrease must have been continuously maintained and must remain federally enforceable *after* the modification is completed. In addition, where a facility has in the past obtained a construction permit for an emissions unit that was never actually operated, the facility cannot claim emission "reductions" due to its past or continued refrain from operating such a unit.[133] Finally, contemporaneous decreases are "creditable" only to the extent that they are of the same pollutants as the emission increases from the modification, and have the same "qualitative significance for public health and welfare."[134]

So, the "net emissions increase" is the "raw emissions increase," minus contemporaneous and creditable decreases, plus contemporaneous and creditable increases. Even if the "raw" emissions increase meets the "significance" thresholds of 40 C.F.R. § 51.166(b)(23), the modification will not trigger NSR if the "net" increase does not also meet those thresholds; that is, the facility can still "net out." However, if the "net" emissions increase of even one pollutant meets its threshold, then the expansion triggers NSR and will require a construction permit.

2. Monitoring, Recordkeeping, and Reporting

The monitoring, recordkeeping, and reporting ("MRR") provisions of construction permits are vitally important. Without adequate monitoring,[135] there is no way to determine whether or not facilities are complying with their limits and, consequently, no way to take enforcement action against those who violate their limits. The EPA itself has acknowledged:

> In the absence of effective monitoring, emissions limits can, in effect, be little more than paper requirements. Without meaningful monitoring data, the public, government agencies and facility officials are unable to fully assess a facility's compliance with the Clean Air Act.

Initial Brief of Respondent U.S EPA, Appalachian Power Co. v. EPA, No. 98- 1512 (D.C. Cir., Oct. 25, 1999) *quoted at* 71 Fed. Reg. 75422, 75425 (Dec. 15, 2006).[136]

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[133] EPA NSR Workshop Manual, *supra* note 35, at A.38.

[134] 40 C.F.R. § 51.166(b)(3)(vi)(*c*); EPA NSR Workshop Manual, *supra* note 35, at A.38 to A.39.

[135] The term "monitoring" sometimes refers collectively to the monitoring, recordkeeping, and reporting ("MRR") requirements.

[136] Ensuring adequate monitoring in construction permits may become all the more important if environmental groups are not successful in their current Title V monitoring rule litigation, in which EIP, the Natural Resources Defense Council ("NRDC"), and the Sierra Club, represented by Earthjustice, have challenged an EPA rule which precludes permitting authorities and the EPA itself from including "periodic monitoring" provisions in Title V permits sufficient to ensure compliance with the CAA, as required by the Act, even if the permitting authorities or EPA determine that the monitoring provisions in underlying provisions (such as NSR construction permits) are not sufficient to ensure compliance with the Act. The case is Environmental Integrity Project, *et al.* v. U.S. Environmental Protection Agency, (D.C. Cir., docket No. 04-1243, consolidated with No. 07-1039) (filed Feb. 12, 2007). The rule being challenged is available at http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/E6-21427.pdf.

Thus, each "emission limit" set forth in the permit must include a periodic monitoring requirement. The monitoring requirement must be clear, understandable, specific, mandatory, unambiguous, and practically enforceable. In order to be practically enforceable, the monitoring requirements must be (among other things[137]) accompanied by similarly unambiguous recordkeeping and reporting requirements.[138]

The EPA has observed that:

> The term *emission limit* includes mass, rate and concentration limits, technology requirements, percent reduction requirements, work practice standards, process or control device parameters, and design, operational, or maintenance requirements.[139]

The permit should include MRR requirements to demonstrate compliance with all of these types of limits; not simply the straightforward pollution concentration limits. In reviewing the monitoring provisions of a construction permit, you should consider whether those provisions: 1) yield reliable data; 2) from the relevant time period; 3) that are representative of the source's compliance; 4) and that will assure compliance with the emissions limits.[140]

a. Types of Monitoring Technology

The term "monitor" "refers to a wide variety of instrumentation used to measure the concentration of … gaseous compounds, particulate matter and physical properties such as opacity in a waste gas stream."[141] Types of monitoring include Continuous Emission Monitoring Systems ("CEMS"), Continuous Opacity Monitoring Systems ("COMS"),[142] Predictive Emission Monitoring Systems ("PEMS"), Leak Detection and Repair ("LDAR"), and stack tests.[143]

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[137] Additional "practical enforceability" considerations are discussed below.

[138] EPA NSR Workshop Manual, *supra* note 35, at A.5.

[139] "Draft Title V Permit Review Guidelines (Rev. 1): Periodic Monitoring," U.S. Environmental Protection Agency, Region 9 (Sept. 9, 1999) at III-90, *available at* http://www.epa.gov/region09/air/permit/titlev-guidelines/periodic-monitoring.pdf (*hereinafter* "EPA Title V Guidelines – Periodic Monitoring"). *See also,* 40 C.F.R. § 64.1 (definition of "emission limitation or standard").

[140] *Id*. at III-91.

[141] EPA document EPA/452/B-02-001, "EPA Air Pollution Control Cost Manual," U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park (6th ed., Jan. 2002) at 4.3, *available at* http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf (*hereinafter* "EPA Cost Manual"). *See also*, 40 C.F.R. § 64.1 (definition of "monitoring").

[142] At the time of publication of this Handbook, the EPA is proposing to overhaul the NSPS applicable to oil refineries. *See* Proposed Standards of Performance for Petroleum Refineries, 72 Fed. Reg. 27178 (May 14, 2007) (to be codified at 40 C.F.R. Part 60, subparts J and Ja), *available at* http://a257.g.akamaitech.net/7/257/2422/01jan20071800/edocket.access.gpo.gov/2007/pdf/E7-8547.pdf. The proposed rule would omit an opacity standard for FCCUs because more effective PM CEMS are

CEMS are the best monitoring systems, and perform "a direct measurement of pollutant concentration from a duct or stack on a continuous or periodic basis."[144] COMS are a subset of CEMS that measure opacity (an indicator of particulate matter emissions). For a detailed description of available CEMS and COMS, *see* EPA document EPA/452/B-02-001, "EPA Emission Control Cost Manual," section 2, chapter 4, available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf, and EPA's Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/ (click on both "monitoring" and "methods").

PEMS (sometimes called "parametric" or "surrogate" monitoring) perform indirect measurements by monitoring key "parameters" of the pollution control or process equipment (*e.g.*, rather than measuring the amount of SO_2 coming out of the stack, the refinery would measure its fuel sulfur content and fuel usage).[145] Unlike CEMS, which can monitor emissions of multiple pollutants simultaneously, each PEMS can usually monitor only a single pollutant.[146] If a facility uses PEMS, the permit should require that the facility demonstrate the correlation between the measured parameter and the regulated pollutant,[147] and that the facility periodically verify this correlation using direct measurement, such as a stack test.[148]

LDAR programs typically use a portable VOC detection device to check for "fugitive emissions" of hydrocarbons (*i.e.*, leaks from valves, pumps, tanks, flanges, et cetera).[149] The EPA has observed that "[w]hile individual leaks are typically small, the sum of all fugitive leaks [from the thousands of potential sources] at a refinery can be one of its largest emission sources."[150] An effective LDAR program can reduce fugitive emissions by over 60%.[151] The LDAR program should be a "directed" program (follow-up testing is done to make sure that the leak is fixed) rather than "non-directed" (no

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available to *directly* monitor PM, rather than monitoring opacity as a surrogate for PM emissions (via COMS). 72 Fed. Reg. at 27191. The Environmental Integrity Project, together with the Sierra Club, has submitted comments to the proposed refinery NSPS arguing that a monitored opacity limit is still necessary, *along with* CEMS for PM (*i.e.*, COMS for opacity). Those comments are available at http://www.environmentalintegrity.org/pub462.cfm.

143 For an overview of monitoring methods, *see* EPA's Technology Transfer Network – Emission Measurement Center at http://www.epa.gov/ttn/emc/ (click on both "monitoring" and "methods").

144 EPA Cost Manual, *supra* note 141, at 4.3.

145 *Id*. at 4.3 and 4.18; *See also*, 40 C.F.R. § 64.1 (definition of "predictive emission monitoring system"); and http://www.epa.gov/ttn/emc/monitor.html.

146 EPA Cost Manual, *supra* note 141, at 4.15.

147 *Id*. at 4.3.

148 *Id*. at 4.14.

149 ABCs of NSR, *supra* note 26, at 87, *citing* Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" (Jan. 26, 2003).

150 EPA Refinery Sector Notebook, *supra* note 7, at 32.

151 *Id*. at 62 (citation omitted).

follow-up testing is done), and should clearly require repairs within a short and specific timeframe, using mandatory rather than permissive language (*e.g.*, "all leaks shall be repaired within fifteen days," rather than "every effort will be made to repair leaks as soon as possible").[152]

Stack tests are direct measurements of stack emissions done "by hand;" that is, they are labor intensive and done by trained stack testers. Stack tests provide a "snapshot" of emissions, and therefore should be conducted when the facility is operating at full capacity to give a representative sample. Stack tests should be done shortly after a new or modified process is started up (and periodically thereafter), and should demonstrate compliance with the "maximum allowable emission rate table" ("MAERT") contained in the construction permit.[153]

Also, EPA often refers to numbered "test methods." For example, EPA's test "method 9" refers to a "visual determination of the opacity of emissions from stationary sources." 40 C.F.R. Part 60, Appendix A. That is, "opacity" (which is caused by the particulate matter ("PM") emitted from smoke stacks, and is thus a "surrogate" for measuring PM emissions), is determined by someone *looking* at it with the naked eye.[154] All of the EPA "test methods" can be found at 40 C.F.R. Part 60, Appendix A, available at http://www.access.gpo.gov/nara/cfr/waisidx_06/40cfrv7_06.html.

An important monitoring technology to keep in mind is "Fourier Transformation Infrared Spectroscopy" ("FTIR"). The EPA explains:

> The FTIR technology … has the capability to measure more than 100 of the 189 Hazardous Air Pollutants (HAPs) listed in Title III of the Clean Air Act Amendments of 1990 (CAAA). Upon passage of the CAAA, measurement methods existed for only 40 of the HAPs. The FTIR has the capability of measuring multiple compounds simultaneously, thus providing an advantage over current measurement methods which measure only one or several HAPs; FTIR can provide a distinct cost advantage since it can be used to replace several traditional methods (cost savings can vary depending on the number of compounds present).

EPA Technology Transfer Network – Emission Measurement Center, *available at* http://www.epa.gov/ttn/emc/monitor.html#ftir. Similarly, the EPA Cost Manual, *supra* note 141, states:

> [FTIR] detects compounds based on the absorption of infrared light at critical wavelengths. … Current FTIR CEMs can accurately monitor up to six gaseous compounds (SO_2, NO_x, CO, HCl, CO_2, and O_2), various

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152 Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" at 2 (Jan. 26, 2003).

153 *Id*. at 1.

154 *See* note 142, *supra*.

> hazardous air pollutants, and volatile organic compounds simultaneously. … Although FTIR instruments tend to be more expensive than other analyzers, the ability to monitor multiple pollutants with one instrument *improves its cost effectiveness*.

EPA Cost Manual, *supra* note 141, at 4.10 (emphasis added).

Finally, an important new technology to keep in mind, especially for LDAR, is "differential light absorption and ranging" ("DIAL").[155] The Alberta Research Council, Inc., explains that:

> [DIAL] is a laser-based method that can remotely measure concentration profiles of hydrocarbons and other gases in the atmosphere at distances up to several hundred meters…. Recently developed gas leak imaging cameras are modified infrared video cameras that visually indicate hydrocarbon plumes from leaking equipment. With these cameras, leaks can quickly be identified and a video record made of the leaks. A survey of fugitive emissions was completed over a period of ten days at an Alberta refinery with the DIAL method…. The gas leak imaging camera was simple to use and required minimal training. The camera was an effective method for locating leaks of hydrocarbon gases to the atmosphere. The camera located both indoor and outdoor leaks and also remotely located leaks in high or inaccessible equipment. Since the completion of this project, the refinery has purchased a gas leak imaging camera for routine use at the site.[156]

In fact, the DIAL study found that, compared with emission factor[157] estimates, DIAL detected 33 times more VOC and *96 times more benzene* (a known carcinogen) from storage emissions, and 12 times more VOC and 8 times more benzene from fugitive emissions.[158]

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[155] The acronym "DIAL" stands for "Differential Absorption LIDAR," and "LIDAR" stands for "Light Detection and Ranging."

[156] Allan Chambers, P.Eng. and Mel Strosher, "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection," (Alberta Research Council, March 31, 2006 – revised November 1, 2006) at iv, *available at* http://www.arc.ab.ca/ARC-Admin/UploadedDocs/Dial%20Final%20Report%20Nov06.pdf (*hereinafter* "DIAL Study").

[157] Refineries often use "emission factors" to determine the amount of pollution emitted, and to report those emissions to the U.S. EPA for inclusion in the Toxics Release Inventory ("TRI") as required by law. The EPA has explained that: "An emissions factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant…. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category…." *See* http://www.epa.gov/ttn/chief/ap42/index.html.

[158] DIAL Study, *supra* note 156, at 17-18.

b. Practical Enforceability

As noted above, the monitoring requirements in the permit must be "practically enforceable." "Practical enforceability" requires that the monitoring provisions: 1) are unambiguous; 2) are accompanied by unambiguous recordkeeping and reporting requirements; 3) do not allow non-compliance; and 4) do not limit the use of "credible evidence" in demonstrating non-compliance. The EPA has elaborated:

> Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions.

EPA NSR Workshop Manual, *supra* note 35, at Appendix C, page 3.

i. Ambiguity

The EPA has specifically identified the following ambiguous language that "may indicate practical enforceability problems:"[159]

Ambiguous Language That May Indicate Practical Enforceability Problems[160]

Problem Language	Discussion	Correction
"Normally," as in: "The permittee shall normally inspect the unit daily."	The term "normally" is subject to interpretation. Is the permittee still "normally" inspecting on a daily basis if inspections take place only 5 days out of 7? This language may place a burden on the permitting authority to show that the source's failure to inspect daily violated the requirement to "normally" inspect the unit daily.	Require that specific language be substituted for ambiguous language. Example: "The permittee shall inspect the unit daily." If necessary to allow for missed inspections, the permit could include a data recovery provision.

[159] "Draft Title V Permit Review Guidelines (Rev. 1): Practical Enforceability," U.S. Environmental Protection Agency, Region 9 (Sept. 9, 1999) at III-60, *available at* http://www.epa.gov/region09/air/permit/titlev-guidelines/practical-enforceability.pdf (*hereinafter* "EPA Title V Guidelines – Practical Enforceability"). Although this guidance is directed to Title V permit reviewers, this analysis is equally applicable to the review of a draft construction permit.

[160] Excerpted from EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-60 to III-62. *See also*, Appendix D to this Handbook.

"As soon as possible; promptly," as in: "The permittee shall take corrective action as soon as possible."	"As soon as possible" and "promptly" are open-ended. Without an outer limit defined in the permit, the burden may be on the permitting authority to prove that the source could or should have acted sooner.	Require that an outer time limit be set on any actions required to occur "as soon as possible" or "promptly." Example: "The permittee shall take corrective action as soon as possible but no later than within 24 hours."
"Significant," as in: "The permittee shall take corrective action if parameters are significantly out of range."	"Significant" must be defined for the permit to be enforceable. Otherwise, the burden may be on the permitting authority to show that a problem is significant.	Specify parameter levels or ranges which will trigger action. For example: "The permittee shall take corrective action if parameters are more than 10% out of the range defined in condition xx." Or "The permittee shall take corrective action if pressure drop is less than 15 inches for more than one hour."
"Should" or "may," as in: "The permittee should inspect daily. The permittee may test monthly."	"Should" indicates a preference, rather than a requirement, and is not appropriate for permit conditions unless the underlying applicable requirement contains provisions that are not mandatory but are recommendations only. "May" indicates an option, rather than a requirement, and is not appropriate for permit conditions.	Require that all required permit terms use "shall" or "must." For example: "The permittee must inspect daily," or "the permittee shall test monthly."
"As suggested by the manufacturer's specifications," as in: "The permittee shall maintain pressure drop as suggested by the manufacturer's specifications."	It is acceptable to use the manufacturer's recommendations as the basis for the numbers that go into the permit if there is no better data. However, the specific numbers must be incorporated into the permit rather than a reference to a document which may not include clear	Require that the specific numbers (which may be based on the manufacturer's recommendations) be included in the permit term. For example: "The permittee shall maintain pressure drop greater than 15 inches."

	requirements.	
"Take reasonable precautions," as in: "The permittee shall take reasonable precautions to reduce fugitive emissions."	"Reasonable precautions" may be too subjective to be practically enforceable. The permit must identify the minimum activities that constitute "reasonable precautions."	Require the permit to include the specific measures that must be taken. For example: "The permittee shall conduct monthly audits of the facility to assure that the minimum reasonable precautions for preventing fugitive emissions are implemented and shall maintain records in accordance with condition xx. For the purposes of this condition, reasonable precautions shall include but are not limited to the following: Storing and mixing volatile materials in covered containers; storing all solvents or solvent containing cloth or other material used for surface preparation in closed containers; … [other specific conditions]."
"Use best engineering practices," as in: "The permittee shall use best engineering practices to operate and maintain the boiler."	This is the same issue as "reasonable precautions." To be practically enforceable, "best engineering practices" must be defined/specified in the permit.	Require that the engineering practices be specified in the permit. For example: "The permittee shall use best engineering practices to operate and maintain the boiler which shall include but not be limited to servicing the boilers at least once each calendar year to assure proper combustion is occurring and that the units are in proper operating condition."

If you find any of the "problem language" in a draft or proposed permit, your comments should identify the language, suggest an alternative such as the "correction" language, and provide an explanation such as those given in the "discussion" section, above.

ii. Recordkeeping and Reporting

"Practical enforceability" also requires that the monitoring provisions are accompanied by unambiguous recordkeeping and reporting requirements. The permit should clearly state: 1) what records must be kept; 2) how long the records must be kept;[161] 3) what the facility must report; 4) to whom the facility must report; 5) how the facility must report (*e.g.*, electronically or otherwise); and 6) how frequently the facility must report. Some records that the permit should require be kept on-site and also submitted to the permitting authority include: 1) the name and location of each processing unit tested and/or monitored; 2) the dates and times of testing and/or monitoring; 3) the test method, instrument calibration, or other quality assurance ("QA") information; 4) the monitoring and/or testing results; and 5) the date and description of leak corrections and follow-up.[162]

iii. Permitted Non-Compliance

"Practical enforceability" also requires that the monitoring provisions do not allow non-compliance. The EPA has specifically identified at least two types of provisions which may improperly allow non-compliance: 1) where satisfaction of a permit requirement is left to the discretion of the director of the permitting authority ("Director's discretion"); and 2) where the permit excuses emissions in excess of permitted limits during times of "startup / shutdown and malfunction."[163]

The EPA has stated that "Director's discretion" provisions are "problematic and should not be included in [a] permit"[164] because they impair practical enforceability by allowing non-compliance. Such provisions are "phrased in such a way that the decision as to whether the condition is met is left to the director of the permitting authority," such as: "The reference test method is EPA Method 5 or other method approved by the Director."[165] Practical enforceability is undermined because "EPA and citizens would have difficulty disputing a finding by the Director…."[166] In the "test method" example, the provision "would allow the source to negotiate a different test method 'off permit' and bypass the process required for approval of alternative test methods." [167] EPA suggests that an alternative to the "Director's discretion" provision is "to include specific options up front in the permit," such as: "The source may use an alternative control

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[161] In order to comply with Title V permit regulations, all records must be kept for *at least* five years.

[162] *See* ABCs of NSR, *supra* note 26, at 89-90. *See also*, Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" at 2-3 (Jan. 26, 2003).

[163] EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-58 to III-59. "Startup, shutdown, and *maintenance*" ("SSM") and "upsets" ("malfunctions") are more fully addressed below.

[164] *Id*. at III-58.

[165] *Id*.

[166] *Id*.

[167] *Id*.

device that achieves an overall control efficiency of 99%."[168] When reviewing a proposed construction permit, you should watch for any "Director's discretion" provisions and request that such provisions be removed in favor of specific criteria.

The EPA has also identified "startup / shutdown and malfunction" provisions (sometimes called "excess emissions provisions" or "upset" provisions) as potentially undermining practical enforceability by allowing non-compliance.[169] These provisions might allow emissions *in excess of permit limits* during times of startup and shutdown, and/or when process or pollution control equipment breaks down. Excess emissions provisions are discussed in detail below.

iv. Limiting "Credible Evidence"

Section 113(a) of the CAA authorizes EPA to bring enforcement actions "on the basis of any information available to the Administrator." Based on this authority, the EPA issued the "Credible Evidence Rule" in 1997, clarifying that "EPA, states and citizens will be able to use [any] credible evidence to assess a source's compliance status and respond to noncompliance,"[170] and that "enforcement authorities can prosecute actions based exclusively on any credible evidence, without the need to rely on any data from a particular reference test."[171] That is, whether evidence is "credible" will be determined by a court or administrative law judge, and such evidence may not be limited by the permit. Any permit language that purports to limit compliance determinations to particular tests, or to deem compliance to have been demonstrated based on a specific test, undermines practical enforceability and should be removed.[172]

The EPA has specifically identified the following unacceptable credible evidence-limiting language:

<u>Unacceptable Credible Evidence-Limiting Language</u>[173]

Type of Language	**Examples**
Language that specifies that only certain types of data can be used to determine compliance	• "The monitoring methods specified in this permit are the sole methods by which compliance with the associated limit is determined."

[168] *Id*.

[169] *Id*. at III-59.

[170] 62 Fed. Reg. 8314, 8315 (Feb. 24, 1997).

[171] *Id*. at 8316.

[172] EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-63.

[173] Excerpted from EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-63 to III-64. *See also*, Appendix E to this Handbook.

	● "Monitoring and reporting requirements are requirements that the permittee uses to determine compliance...." "Compliance with this provision will be demonstrated by ... (insert periodic monitoring provisions)."
Language that specifies that certain types of data are more credible than others	● "Reference test method results supersede parametric monitoring data." ● "The EPA Reference Test Method results supersede CEMS data."
Language that excuses violations under certain conditions	● "The permittee is considered to be in compliance if less than 5% of any CEMS monitored emission limit averaging periods exceeds the associated emission limit." ● "If the permitting authority does not take action on an excess emissions demonstration by responding to the permittee in writing within 90 days of receipt, the permitting authority will be deemed to have made a determination that the excess emissions were unavoidable." ● "Excess emissions that are unavoidable are not violations of permit terms." ● "A 'deviation from permit requirements' shall not include any incidents whose duration is less than 24 hours from the time of discovery by the permittee."

If you find any such credible evidence-limiting language in a proposed permit, your comments should request removal of the language based on the EPA's "Credible Evidence Rule" at 62 Fed. Reg. 8314, 8315 (Feb. 24, 1997).

3. "Startup, Shutdown & Maintenance" ("SSM") and Malfunctions ("Upsets")

"Startup / shutdown and maintenance" ("SSM"), and malfunctions of process or pollution control equipment ("upsets"), are non-routine events that cause refineries to emit pollution in excess of permit limits. During upset and SSM events, emissions are commonly sent to a flare or released directly into the air. Emissions from SSM and upsets can be a major source of pollution from refineries (sometimes exceeding their total "routine" emissions of some pollutants). The permit terms relating to such events are commonly called "excess emissions provisions,"[174] and typically allow emissions in excess of permit limits during such events.[175]

The EPA's "Title V Permit Review Guidelines" state that such provisions are permissible if they allow excess emissions *only* when it is "technologically impossible" to comply with the limits (during startup / shutdown), or when it is "beyond the source's control" to stay within limits (during malfunctions). The EPA explains that such provisions must be removed from a draft permit if they "excuse[] emissions that should be under a source's control, or allows for Director's discretion."[176]

Further, the EPA's "Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown" states that "all periods of excess emissions must be considered violations…. [and] any provision that allows for an automatic exemption for excess emissions is prohibited."[177] However, the Policy goes on to explain that states may provide in their SIPs for "affirmative defenses" (meaning that the refinery will have the burden of demonstrating all elements of the defense) to monetary penalties (but not defenses to injunctions, *i.e.*, orders to make refineries fix the problem) for excess emissions under certain narrow criteria. Some companies try to manipulate the affirmative defenses to avoid liability for SSM and upset emissions, which is one reason why upsets keep happening.

The minimum criteria for the "startup and shutdown" affirmative defense are different from those for the "malfunction" affirmative defense. The EPA states that both

[174] Such provisions might variously be called "startup / shutdown and *malfunction*," "startup, shutdown, *maintenance* and malfunction," "SSM," "SSMM," "excess emissions," and/or "upsets." While there is no uniform definition of "upset," the term should encompass only those events that are truly unavoidable *and unforeseeable*. Because "startup, shutdown, and *maintenance*" activities are entirely foreseeable and expected, they are not true "upsets." Therefore, this Handbook distinguishes between "startup, shutdown, and *maintenance*" ("SSM") and "*malfunctions*" (*i.e.*, "upsets"), and refers to "SSM" and "upsets" collectively as "excess emissions."

[175] The CAA mandates continuous compliance with its pollution limits (CAA § 302(k), 42 U.S.C. § 7602(k)) and does not provide exceptions for excess emissions. Rather, any emissions in excess of federal limits are to be treated as violations. Further, states must adopt emission limits at least as stringent as those in the federal rules. However, as discussed below, despite the CAA's requirement for continuous compliance, EPA's rules and policy allow SSM and upset emissions that exceed pollution limits to escape enforcement under certain circumstances.

[176] EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-59.

[177] Memorandum from Steven A. Herman, Assistant Administrator for Enforcement and Compliance Assurance, U.S. EPA, to U.S. EPA Regional Administrators, Regions I-X, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999), Attachment ("Policy on Excess Emissions During Malfunctions, Startup, and Shutdown") at 1, *available at* http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/excesem2.pdf (*hereinafter* "EPA SSM Policy"). The EPA Policy explains that "automatic exemptions" are "generally applicable provision[s] … that would provide that if certain conditions existed during a period of excess emissions, then those exceedances would not be considered violations." *Id*. at 1, n.2.

sets of criteria are to be interpreted "narrowly."[178] The criteria are as follow (where available in state SIPs):

Minimum Criteria for Excess Emission Affirmative Defenses (Where Available)[179]

Elements of Affirmative Defense for Malfunction Excess Emissions	**Elements of Affirmative Defense for Startup and Shutdown Excess Emissions**
1. **The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator**; 2. **The excess emissions: (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices**; 3. To the maximum extent practicable, the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions; 4. **Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded**…; 5. The amount and duration of the excess emissions … were minimized to the maximum extent practicable during periods of such emissions; 6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;	1. **The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design**; 2. The excess emissions were **not part of a recurring pattern** indicative of inadequate design, operation, or maintenance; 3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; 4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions; 5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable; 6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality; 7. All emission monitoring systems were kept in operation if at all possible; 8. The owner or operator's actions during

[178] *Id*. at 162, at 4.

[179] Excerpted from EPA SSM Policy, *supra* note 177, at 3-4, 6 (emphasis added). *See also*, Appendix F to this Handbook.

7. All emission monitoring systems were kept in operation if at all possible; 8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; 9. **The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance**; and 10. The owner or operator properly and promptly notified the appropriate regulatory authority.	the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and 9. The owner or operator properly and promptly notified the appropriate regulatory authority.

If you find any "excess emissions provisions" in a proposed permit, your comments should reflect the following: 1) ideally, there should be no exceptions or affirmative defenses – emissions from SSM and upset events that exceed limits should be prohibited;[180] 2) where state rules allow an affirmative defense, the scope should be as narrow as possible (remember that affirmative defenses must not be made available for injunctive relief,[181] so permits should make clear that the problem has to be fixed, and that "automatic exemptions" are not allowed[182]); 3) refineries should be required to promptly report emissions[183] and to take steps to prevent recurrence; 4) refineries should not get any affirmative defense for repeat violations;[184] and 5) under no circumstance should emissions during SSM or upset events be treated as "exempt" from the Clean Air Act.

[180] Again, the Clean Air Act mandates continuous compliance with its pollution limits and does not provide exceptions for excess emissions. CAA § 302(k), 42 U.S.C. § 7602(k). Rather, any emissions in excess of federal limits are to be treated as violations. *See also*, Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, U.S. EPA Region 1, at 1-2 (Jan. 28, 1993), *available at* http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/automati.pdf: "Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will *eliminate* violations of emission limitations during such periods." (Emphasis added). Therefore, upsets must be treated as violations and prohibited.

[181] EPA SSM Policy, *supra* note 177, at 3, 6. "Injunctive relief" is a preventative remedy that requires the defendant to stop a particular action (or inaction) in the future, rather than providing monetary compensation for a past injury.

[182] *Id*. at 2-3.

[183] *See, e.g.*, regulations of California's Bay Area Air Quality Management District ("BAAQMD").

[184] *See* U.S. EPA consent decrees with refining companies, *available at* http://www.epa.gov/compliance/resources/cases/civil/caa/oil.

Further, your comments should request: 1) that SSM provisions apply only when it is "technologically impossible" for the refinery to comply with the limits, and where the emissions are short and infrequent, could not have been prevented through careful planning and design, and are not part of a recurring pattern; 2) that upset provisions apply only when it is "beyond the refinery's control" to stay within limits, and where the excess emissions are caused by a sudden, unavoidable breakdown of technology, do not stem from anything that could have been foreseen, planned for, or avoided, and are not part of a recurring pattern; 3) that the provisions be removed from the permit if they "excuse emissions that should be under the refinery's control" or allow for "Director's discretion;" and 4) that the provisions comply with all of the requirements set forth in the EPA's "Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown."

With regard to monitoring and reporting of SSM and upset emissions, your comments should request that the permit require electronic reporting of all excess emissions within 24 hours (toxics reported immediately), that the reports be made available to the public on state agency websites within 72 hours, and that the reports specify, at a minimum:

- the individual pollutants emitted,
- the amount of each pollutant emitted,
- the method of calculating emissions,
- the cause of the emissions,
- the amount by which the emissions exceed regulatory limits,
- the regulatory limits that apply, and
- the actions planned to prevent such excess emissions from occurring in the future.

Finally, permits should subject excess emissions to BACT limits, provide for automatic penalties, require offset reductions in routine emissions, require facilities to shut down after a certain number of excess emission events, and include excess emissions in PTE calculations.

4. Environmental Justice

The U.S. EPA, along with other federal agencies, is directed by Executive Order of the President to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations…."[185] This Executive Order applies to state-issued construction permits issued under "delegated" NSR programs, as well as to the

[185] Executive Order No. 12,898 (Feb. 11, 1994), 59 Fed. Reg. 7629 (Feb. 16, 1994).

U.S. EPA.[186] States with "approved" NSR programs may have their own environmental justice policies.

When environmental justice issues are raised, the U.S. EPA or the state with delegated permitting authority must conduct an environmental justice analysis to determine whether the refinery expansion will have "disproportionately high and adverse human health or environmental effects … on minority populations and low-income populations."[187] The EPA has stated its policy that:

> "Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. … Meaningful involvement means that: (1) people have an opportunity to participate in decisions about activities that may affect their environment and/or health; (2) the public's contribution can influence the regulatory agency's decision; (3) their concerns will be considered in the decision making process; and (4) the decision makers seek out and facilitate the involvement of those potentially affected."[188]

Thus, raising environmental justice issues will result, at minimum, in "consideration" of the issues, and could result in improved permit requirements such as monitoring.

5. Class I Area Impacts

As noted above, no matter what the "net increase" in emissions, a new source or modification is considered "major" if it occurs within 10 kilometers of a "Class I area" (such as certain Wilderness Areas[189]) and the increased emissions would increase the 24-hour average ambient air concentration of a regulated pollutant in the Class I area by at least one microgram per cubic meter (1 $\mu g/m^3$).[190]

However, even if a major new source or modification is located more than 10 kilometers from a Class I area, the permitting authority still must notify the Federal Land

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[186] *In re Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 174 (EAB 1999).

[187] ABCs of NSR, *supra* note 26, at 91.

[188] *See* http://www.epa.gov/compliance/basics/ejbackground.html.

[189] "Mandatory" "Class I areas" include International Parks; National Wilderness Areas (including certain National Wildlife Refuges, National Monuments, and National Seashores) in excess of 5,000 acres; National Memorial Parks in excess of 5,000 acres; and National Parks in excess of 6,000 acres, all of which were in existence on August 7, 1977. 40 C.F.R. § 52.21(e)(1). However, other areas may be designated as "Class I areas." For a list of "Mandatory Class I Areas," *see* EPA NSR Workshop Manual, *supra* note 35, at E.3 – E.6, reproduced as Appendix I to this Handbook.

[190] 40 C.F.R. § 52.21(b)(23)(iii).

Manager ("FLM") in charge of the area if the project may impact the Class I area.[191] This generally means that the FLM should be notified if the major new source or modification is within 100 kilometers of the Class I area.[192] A list of Class I areas, along with their FLM,[193] can be found on pages E.2 – E.6 of the EPA's "NSR Workshop Manual," available at http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf, and reproduced as Appendix I to this Handbook. The EPA has explained:

> If an FLM determines, based on any information available, that a source will adversely impact [air quality related values ("AQRVs")] in a Class I area, the FLM may recommend that the reviewing agency deny issuance of the permit, *even in cases where no applicable increments would be exceeded*. … The FLM of a Class I area has an affirmative responsibility to AQRVs for that area which may be adversely affected by cumulative ambient pollutant concentrations. The FLM is responsible for evaluating a source's projected impact on the AQRVs and recommending that the reviewing agency either approve or disapprove the source's permit application based on anticipated impacts. The FLM also may suggest changes or conditions on a permit. However, the reviewing agency makes the final decisions on permit issuance. The FLM also … makes ambient monitoring recommendations.[194]

The determination of AQRVs and what constitutes "adverse impact" varies from FLM to FLM (*i.e.*, from agency to agency), as well as from Class I area to area (depending on the purposes of the area).[195] Further, where the major new source or modification is in a non-attainment area, and is therefore applying for an NA NSR permit (as opposed to a PSD permit in an attainment area), the FLM may be limited to reviewing

[191] The EPA states: "The PSD regulations specify that the reviewing authority furnish written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the FLM and the official charged with direct responsibility for management of any lands within the area." EPA NSR Workshop Manual, *supra* note 35, at E.12.

[192] ABCs of NSR, *supra* note 26, at 81, *citing* the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (Dec. 2000), *available at* http://www2.nature.nps.gov/air/Permits/flag/flagDoc/background.cfm#legal.

[193] The EPA has explained: "The U.S. Departments of Interior (USDI) and Agriculture (USDA) are the FLM's responsible for protecting and enhancing [air quality related values ("AQRVs")] in Federal Class I areas. Those areas in which the USDI has authority are managed by the [National Park Service ("NPS")] and the [U.S. Fish & Wildlife Service ("FWS")], while the USDA Forest Service separately reviews impacts on Federal Class I national wildernesses under its jurisdiction. … Although the Secretaries of Interior and Agriculture are the FLM's for Federal Class I areas, they have delegated permit review to specific elements within each department. In the USDI, the NPS Air Quality Division reviews PSD permits for both the NPS and FWS. Hence, for sources that may affect wildlife refuges, applicants and reviewing agencies should contact and send correspondence to both the NPS and the wildlife refuge manager located at the refuge." EPA NSR Workshop Manual, *supra* note 35, at E.12 – E.13.

[194] EPA NSR Workshop Manual, *supra* note 35, at E.12 (emphasis added).

[195] For a discussion and examples of AQRVs, *see* EPA NSR Workshop Manual, *supra* note 35, at E.10 – E.12.

"visibility" impacts, rather than a host of AQRVs.[196] In any case, however, if you believe that a major new source or modification will adversely impact a Class I area, you should include those concerns in your comments to the permitting authority, and also notify the appropriate FLM(s).

B. PSD Permit Issues

1. BACT Analysis

As noted above, both PSD and NA NSR permits require the installation of modern pollution control technology, and the level of technology required will be based on whether the permit is an attainment area PSD or a non-attainment area NA NSR permit. If the permit is a PSD permit, then the CAA requires the use of "best available control technology" ("BACT"), but if the permit is an NA NSR permit, then the CAA requires the use of "lowest achievable emission rate" ("LAER") technology. Both BACT and LAER are stringent limitations that require the most technologically feasible pollution control. However, while the BACT determination takes into consideration "economic impacts,"[197] the LAER determination may not consider cost-effectiveness.[198] Therefore, LAER is the most stringent pollution control possible.

The determination of what specific technology qualifies as BACT or LAER is made on a case-by-case basis for each pollutant from each emission unit in each permit. This Handbook suggests, below, specific technologies which should qualify as BACT or LAER for the major oil refinery processes, based on a review of past BACT and LAER determinations, EPA consent decrees with refineries, U.S. EPA and other agency guidance, websites of technology vendors, and the advice of technical experts. Because BACT and LAER determinations are made on a case-specific basis, the specific technology which is chosen as BACT or LAER will vary somewhat from refinery to refinery. However, those determinations are discussed here to provide a rough sketch of *how* the determinations are supposed to be made, which methodology is *not* case-specific, but is to be uniformly applied to all facilities (including refineries). In reviewing a construction permit, in addition to looking for specific technologies, you should make sure that the permitting authority has applied the proper BACT and/or LAER analyses as prescribed by the U.S. EPA.

Although BACT usually consists of pollution control "equipment," it is defined as an "emissions limitation" based on "production processes or available methods, systems, and techniques," and may include "a design, equipment, work practice, operational standard or combination thereof."[199] In order to determine the "emissions limitation"

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[196] ABCs of NSR, *supra* note 26, at 85.

[197] The reviewing authority may "tak[e] into account energy, environmental, and economic impacts and other costs." 40 C.F.R. § 51.166(b)(12).

[198] *See* 40 C.F.R. § 51.165(a)(1)(xiii). *See also*, EPA NSR Workshop Manual, *supra* note 35, at G.3.

[199] 40 C.F.R. § 51.166(b)(12). The EPA has further observed that "[t]he term *emission limit* includes mass, rate and concentration limits, technology requirements, percent reduction requirements, work practice

which constitutes BACT in a given instance, the EPA has prescribed a “top-down” analysis, explaining:

> In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent – or “top” – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority … agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.[200]

This BACT analysis entails five basic steps, summarized as follows:

Key Steps in the “Top-Down” BACT Determination[201]

STEP 1:	IDENTIFY ALL CONTROL TECHNOLOGIES.
●	List is comprehensive (LAER included).
STEP 2:	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.
●	A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.
STEP 3:	RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.
Should include:	

standards, process or control device parameters, and design, operational, or maintenance requirements.” EPA Title V Guidelines – Periodic Monitoring, *supra* note 139, at III-90. *See also*, 40 C.F.R. § 64.1 (the term “emission limitation or standard” “… may be expressed in terms of the pollutant, expressed either as a specific quantity, rate or concentration of emissions (e.g., pounds of SO2 per hour, pounds of SO2 per million British thermal units of fuel input, kilograms of VOC per liter of applied coating solids, or parts per million by volume of SO2) or as the relationship of uncontrolled to controlled emissions (e.g., percentage capture and destruction efficiency of VOC or percentage reduction of SO2). An emission limitation or standard may also be expressed either as a work practice, process or control device parameter, or other form of specific design, equipment, operational, or operation and maintenance requirement.”).

[200] EPA NSR Workshop Manual, *supra* note 35, at B.2.

[201] Excerpted from the EPA NSR Workshop Manual, *supra* note 35, at B.6. *See also*, Appendix G to this Handbook.

	●	control effectiveness (percent pollutant removed);
	●	expected emission rate (tons per year);
	●	expected emission reduction (tons per year);
	●	energy impacts (BTU, kWh);
	●	environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
	●	economic impacts (total cost effectiveness, incremental cost effectiveness).
STEP 4:		EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.
	●	Case-by-case consideration of energy, environmental, and economic impacts.
	●	If top option is not selected as BACT, evaluate next most effective control option.
STEP 5:		SELECT BACT
	●	Most effective option not rejected is BACT.

For a thorough discussion of the "top-down" BACT analysis, *see* chapter B of the EPA's "New Source Review Workshop Manual," available at http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

As the EPA states in "step 2" of the "top-down" analysis: "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review." If such "clear documentation" does not appear, *you should challenge the proposed permit on this basis*.

Perhaps the best way to determine BACT is to find out what technology and limits have been required for other refineries in the recent past,[202] especially by your

[202] The EPA's "RACT / BACT /LAER Clearinghouse" ("RBLC") contains case-specific examples of actual BACT determinations submitted by state and local permitting authorities, as well as links to other resources, although the RBLC is typically 3-4 years out of date. The RBLC is available at http://cfpub1.epa.gov/rblc/htm/bl02.cfm. Also, although the EPA proposed in March, 2007 to remove petroleum refining from the triennial "National Enforcement Priorities" for FY 2008-2010, the previous "Refinery Enforcement Initiative" resulted in 18 consent decrees with refining companies since 2000, which are available at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/ (you can check to find the latest consent decrees at http://cfpub.epa.gov/compliance/cases/index.cfm). In addition, the State of California, which generally has stringent BACT requirements (in fact, California's BACT is sometimes considered LAER since much of the State is in non-attainment), maintains a statewide BACT clearinghouse at http://www.arb.ca.gov/bact/bact.htm. Also, although now somewhat out of date, the U.S. EPA in 2001 issued a memorandum regarding "BACT and LAER for Emission of [NOx] and [VOCs] at Tier 2/Gasoline Sulfur Refinery Projects," memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to all U.S. EPA Regional Air Division Directors (Jan. 19, 2001), *available at* http://epa.gov/region7/programs/artd/air/nsr/nsrmemos/t2bact.pdf. Another resource for actual examples of

permitting authority.[203] Your comments should highlight any instances in which the permitting authority has previously required more stringent BACT limits and request an explanation for the inconsistency.

2. Air Quality Impact Analysis

As discussed above, a PSD permit: 1) must not allow any emissions that would violate a NAAQS for any criteria pollutant, and 2) must not allow emissions in excess of any "PSD increment." A PSD increment is the amount of a regulated pollutant that can be added to an attainment area's total load of that pollutant above the area's "baseline concentration," and the baseline concentration is essentially the amount of the pollutant already in the air when the first complete PSD permit application affecting the area was submitted.

In order to fulfill the fundamental purposes of a PSD permit, the applicant must conduct an air quality analysis of the impact of the proposed new source or modification on the ambient air quality of the attainment area. This analysis is critical, in that it must demonstrate that new emissions from the project, *in conjunction with all potential emissions from other sources in the attainment area, and including secondary emissions*[204] *from the project*, will not result in a violation of any NAAQS or PSD increment. A separate air quality analysis must be performed for each regulated pollutant[205] that will be emitted in a significant amount from a new major source,[206] or for each regulated pollutant for which the net emissions increase from a major modification

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innovative monitoring is http://www.zerowastenetwork.org/success/index.cfm. In order to keep abreast of emerging technology, a useful resource is the "New and Emerging Environmental Technologies" ("NEET") website operated by RTI International (also known as Research Triangle Institute) with the support of the U.S. EPA, available at http://neet.rti.org/.

[203] One way to do this is to compare the most recent construction permits for other refineries in your state. You can find other refineries in your state at http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2004/pdf/table_38.pdf. Once you know the other refineries, you might be able to find their construction permits on your permitting authority's website. If not, and if the permitting authority will not provide them in response to an informal request, then you can obtain them through a Freedom of Information Act ("FOIA") request (discussed above).

[204] "Secondary emissions" are "emissions which occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. … [Such] emissions must be specific, well defined, quantifiable, and impact the same general areas [as] the stationary source modification which causes the secondary emissions. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel." 40 C.F.R. § 51.166(b)(18).

[205] "Regulated pollutants" include the "criteria pollutants" *and other* pollutants as well. *See* 40 C.F.R. § 51.166(b)(49).

[206] A new oil refinery would be considered a "major source" for any criteria pollutant of which it had the potential to emit 100 tpy. 40 C.F.R. § 52.21(b)(1)(i)(a).

will be significant.[207] While each air quality analysis is site-specific, the EPA has explained that, "[g]enerally, the analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project."[208]

That is, the air quality analysis must present a "before" picture (using "ambient monitoring"), and an "after" picture (using "dispersion modeling").

The air quality analysis is typically quite lengthy and highly technical, utilizing complex dispersion modeling and taking account of meteorological and topographical factors.[209] However, you should review the analysis with the following points in mind:

1) The allowable increment is based on the baseline concentration, which is essentially the amount of the pollutant already in the air when the first complete PSD permit application affecting the area was submitted. You should ensure that the calculation of the baseline concentration is adequately documented. In particular, any assumptions in lieu of actual monitoring data must be fully explained.

2) Pre-application ambient data, including both air quality data and meteorological data, "generally must be gathered over a period of at least 1 year and the data are to represent at least the 12-month period immediately preceding receipt of the PSD application."[210] You should ensure that all ambient data are adequate. Again, any assumptions in lieu of actual monitoring data must be fully explained.

3) The actual impact on air quality is determined largely by "dispersion modeling." Again, in general, any assumptions must be fully explained. However, you should consider enlisting the help of an expert if at all possible in reviewing the dispersion modeling.[211]

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[207] A modification is considered "major" if the "net increase" in potential emissions meets any of the thresholds for the various pollutants listed at 40 C.F.R. § 51.166(b)(23)(i), *or* if the modification occurs within 10 kilometers of a "Class I area" (*see* Appendix I to this Handbook) and the increased emissions would effect the air quality of the Class I area by increasing the 24-hour average concentration of any regulated pollutant in the ambient air by at least one microgram per cubic meter (1 $\mu g/m^3$). 40 C.F.R. § 52.21(b)(23)(iii).

[208] EPA NSR Workshop Manual, *supra* note 35, at C.1 – C.2.

[209] For an overview of air quality analyses, *see* chapter C of the EPA NSR Workshop Manual, *supra* note 35, *available at* http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

[210] EPA NSR Workshop Manual, *supra* note 35, at C.16.

[211] For an overview of dispersion modeling analysis, *see* EPA NSR Workshop Manual, *supra* note 35, at C.24 – C.53, *available at* http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

4) The analysis must demonstrate that new emissions from the project, *in conjunction with all potential emissions from other sources in the attainment area, and including secondary emissions from the project*, will not result in a violation of any NAAQS or PSD increment. To this end, the PSD permit application should include a "source inventory" (sometimes called an "emissions inventory"). First, you should ensure that all other sources and secondary emissions are included.[212] Second, you should ensure that the inventory considers total *permitted* (or "potential") emissions, rather than *actual* emissions, in determining whether a *NAAQS* violation could occur,[213] (although EPA policy allows the use of actual emissions in determining whether a *PSD increment* violation could occur).[214]

3. Additional Impacts Analysis (Soil & Vegetation, Growth, and Visibility)

All PSD permit applicants must submit with their application an "additional impacts analysis," which is distinct from the "air quality impacts analysis." The "additional impacts analysis" addresses impacts to: 1) soil and vegetation; 2) "growth" anticipated to be associated with the project; and 3) visibility. While the EPA observes that "the analysis does not lend itself to a 'cookbook' approach,"[215] the Agency states that "[i]t is important that the analysis fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis."[216]

First, the applicant must include a consideration of impacts on vegetation, and should include an inventory of "all vegetation with any commercial or recreational value."[217] A good reference regarding air emission impacts on soil and vegetation is "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 450/2-81-078, U.S. EPA (Dec. 12, 1980), *available at* http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/epadocs/EPA-Screening%20Procedure,%20Air.pdf.

Next, the applicant must include an estimate of the increased emissions from industrial, commercial, and residential growth associated with the proposed project. "Associated growth" is "growth that comes about as the result of the construction or modification of a source, but is not a part of that source."[218] The emissions from such

[212] "Secondary emissions" can be found in the "additional impacts analysis – growth" portion of the PSD permit application, discussed below.

[213] The emission limits in the permit (or total "potential" emissions) should be higher than actual emissions. In any event, unless permit violations are occurring, actual emissions should never be higher than the permitted emissions.

[214] ABCs of NSR, *supra* note 26, at 78.

[215] EPA NSR Workshop Manual, *supra* note 35, at D.2

[216] *Id*. at D.1.

[217] *Id*. at D.4.

[218] *Id*. at D.3, n.5.

associated growth are "secondary emissions."[219] As noted above, such secondary emissions must be considered in determining whether new emissions from the project will result in a violation of any NAAQS or PSD increment.

Finally, the applicant must include a consideration of visibility impairment within the attainment area caused by the increased emissions. The EPA states that "the visibility analysis required here is distinct from the Class I area visibility analysis requirement."[220] An increase in "extinction" of sunlight of 5% is "worthy of concern," and a 10% increase in "extinction" is "significant."[221]

C. NA NSR Permit Issues

The requirements of an NA NSR permit application differ from those of a PSD permit application because, while there is still some "good air" left to be protected in an attainment area, a non-attainment area is already completely polluted with regard to the relevant criteria pollutant. Therefore, there is no need for "air quality impacts" or "additional impacts" analyses, as the goal of an NA NSR permit is to prevent *any* additional impact. In order to do so, the NA NSR applicant must demonstrate emission reductions (commonly called "offsets") from other sources impacting the non-attainment area that equal the proposed emission increases from the new project. Further, the applicant must demonstrate that all of its other facilities in the state are in compliance with the CAA or are coming into compliance. Finally, rather than BACT, an NA NSR applicant must utilize technology which achieves the "lowest achievable emission rate" ("LAER").

1. LAER Analysis

While the BACT determination takes into consideration "economic impacts,"[222] the LAER determination may *not* consider cost-effectiveness.[223] Therefore, LAER is simply the most stringent pollution control possible, and there is no need to go through the "top-down" BACT analysis. However, in order to think of the process in the language of the BACT analysis, the NA NSR applicant would: 1) identify all control technologies; 2) rank them in order of effectiveness; and 3) choose the most effective as LAER.

LAER is defined as the more stringent emission rate of either: a) the most stringent limit contained in the SIP applicable to the source class or category; or b) the

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[219] *See* notes 204 and 212, *supra*.

[220] EPA NSR Workshop Manual, *supra* note 35, at D.5.

[221] ABCs of NSR, *supra* note 26, at 80, *citing* the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (Dec. 2000), *available at* http://www2.nature.nps.gov/air/Permits/flag/flagDoc/background.cfm#legal.

[222] The reviewing authority may "tak[e] into account energy, environmental, and economic impacts and other costs." 40 C.F.R. § 51.166(b)(12).

[223] *See* 40 C.F.R. § 51.165(a)(1)(xiii). *See also*, EPA NSR Workshop Manual, *supra* note 35, at G.3.

most stringent limit which has been achieved in practice by sources of the same class or category.[224] Like BACT, the determination of what specific technology qualifies as LAER is made on a case-by-case basis for each pollutant from each emission unit in each permit. Specific technologies that you should look for and/or request as LAER for oil refineries are listed below, and can also be found in Appendix B to this Handbook.

2. Emission Reductions / Offsets

The goal of an NA NSR permit is to ensure that industrial growth does not hinder a non-attainment area's progress toward attainment of the NAAQS. Therefore, an NA NSR permit must require the applicant to obtain "offsets" (sometimes called "emission reduction credits" ("ERCs")) from emission reduction projects at the same source or from other existing sources impacting the same area. In general, the offsets must: "(1) offset the emissions increase from the new source or modification and (2) provide a net air quality benefit."[225] The offsets are particular to each criteria pollutant for which the area is in non-attainment. The offset must be *at least* as much as the increase of the criteria pollutant (that is, the "offset ratio" of reductions to new emissions must be at least 1:1), and the offset ratios for NO_x and VOCs in ozone non-attainment areas must be greater than 1:1 and increase depending upon the severity of the non-attainment.[226] The EPA has stated that "[a]cceptable offsets … must be creditable, quantifiable, federally enforceable, and permanent."[227]

Regarding "creditability," the EPA explains that "emissions reductions which have resulted from some other regulatory action are not available as offsets."[228] That is, as the EPA has explained in the context of "netting" (discussed above), the offset must not have been previously relied upon by the permitting authority in issuing an NA NSR or PSD permit to the facility:

> A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment [for a PSD permit] or ambient standard [("NAAQS") for an NA NSR permit]. In other words, an emissions change [(*i.e.*, decrease)] … which was considered in the issuance of a previous PSD permit for the source is <u>not</u> included in the source's "net emissions increase" calculation. This is done to avoid "double counting" of emissions changes.[229]

In the context of "offsets," the EPA continues:

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[224] 40 C.F.R. § 51.165(a)(1)(xiii). *See also*, EPA NSR Workshop Manual, *supra* note 35, at G.2.

[225] EPA NSR Workshop Manual, *supra* note 35, at G.5.

[226] *See* CAA § 182, 42 U.S.C. § 7511a.

[227] EPA NSR Workshop Manual, *supra* note 35, at G.6.

[228] *Id*. at G.7.

[229] *Id*. at A.40 (emphasis in original).

> [E]missions reductions already required by a SIP cannot be counted as offsets. Also, sources subject to an NSPS in an area with less stringent SIP limits cannot use the difference between the SIP and NSPS limits as an offset. In addition, ***any emissions reductions already counted in major modification "netting" may not be used as offsets***.[230]

In addition, as was the case with "netting," where a facility has in the past obtained a construction permit for an emissions unit that was never actually operated, the facility cannot claim "decreased" reductions from such a unit.[231] Similarly, where the permit allows an emissions unit to emit more than it actually emits, the source cannot claim the "permit limit" as the "offset" by shutting down the unit. Rather, the source can only claim the *actual* historical emissions.[232] The difference is commonly called a "paper reduction" and is not permissible.

Another issue to keep in mind is the location of the emission reductions. The EPA has stated that "offsets should be located as close to the proposed site as possible" and generally "within the same air quality control region."[233] However, you may argue in your comments that principles of environmental justice (discussed above) dictate that the emission reductions come from sources in the same community as the new emission increases.

3. Demonstration of Compliance

An applicant for an NA NSR permit "must certify that all major stationary sources owned or operated by the applicant … in that State are in compliance with all applicable emissions limitations and standards under the CAA."[234] Your state's permitting authority should be able to tell you whether the refiner owns or operates other facilities in the state, or else that information might be on the agency's website. If the other facilities are not in compliance with the CAA and have no plan to come into compliance, then the state cannot issue an NA NSR permit (and, in some states, cannot issue a PSD permit). A useful resource in this regard is the U.S. EPA's online database, "Enforcement and Compliance History Online" ("ECHO"), available at http://www.epa.gov/Compliance/data/systems/multimedia/echo.html. You may also be able to check for "notices of violation" ("NOVs") or other compliance history on your permitting authority's website.

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[230] *Id*. at G.7 (emphases added).

[231] *Id*. at A.38.

[232] For example, if an emissions unit is permitted to emit 100 tpy of NO_x, but historically has only emitted 80 tpy, then shutting down the unit only results in an "offset" of 80 tpy, and not 100 tpy. The 20 tpy difference is an impermissible "paper reduction." ABCs of NSR, *supra* note 26, at 83.

[233] EPA NSR Workshop Manual, *supra* note 35, at G.6.

[234] *Id*. at G.9.

4. Alternatives Analysis

Finally, the CAA requires that NA NSR permits be issued only if:

> [A]n analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.[235]

You should review the NA NSR permit application to ensure that an alternatives analysis has been done. If it has not been done, then the permit should not be issued. If the alternatives analysis has been done, then you should review it to ensure that it is adequate. In commenting on the analysis, you should raise any environmental justice concerns that you believe have not been adequately addressed.

D. Specific BACT (PSD) and LAER (NA NSR) Technologies to Seek in Oil Refinery Construction Permits

As noted above, the determination of the specific technology that qualifies as BACT or LAER is made on a case-by-case basis for each pollutant from each emission unit in each permit for each refinery. However, without the aid of a technical expert, it may be extremely difficult, if not impossible, to evaluate and comment on the specific technology chosen as BACT or LAER in a proposed permit. Therefore, the table below identifies specific technologies that, in general, should qualify as BACT or LAER for the main oil refinery processes. This summary is based on a review of past BACT and LAER determinations, EPA consent decrees with refineries, EPA and other agency guidance, websites of technology vendors, and the advice of technical experts.[236]

[235] CAA § 173(a)(5), 42 U.S.C. § 7503(a)(5).

[236] The EPA's "RACT / BACT /LAER Clearinghouse" ("RBLC") contains case-specific examples of actual BACT determinations submitted by state and local permitting authorities, as well as links to other resources, although the RBLC is typically 3-4 years out of date. The RBLC is available at http://cfpub1.epa.gov/rblc/htm/bl02.cfm. Also, although the EPA proposed in March, 2007 to remove petroleum refining from the triennial "National Enforcement Priorities" for FY 2008-2010, the previous "Refinery Enforcement Initiative" resulted in 18 consent decrees with refining companies since 2000, which are available at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/ (you can check to find the latest consent decrees at http://cfpub.epa.gov/compliance/cases/index.cfm). In addition, the State of California, which generally has stringent BACT requirements (in fact, California's BACT is sometimes considered LAER since much of the State is in non-attainment), maintains a statewide BACT clearinghouse at http://www.arb.ca.gov/bact/bact.htm. Also, although now somewhat out of date, the U.S. EPA in 2001 issued a memorandum regarding "BACT and LAER for Emission of [NOx] and [VOCs] at Tier 2/Gasoline Sulfur Refinery Projects," memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to all U.S. EPA Regional Air Division Directors (Jan. 19, 2001), *available at* http://epa.gov/region7/programs/artd/air/nsr/nsrmemos/t2bact.pdf. Another resource for actual examples of innovative monitoring is http://www.zerowastenetwork.org/success/index.cfm.

If you are not able to undertake a detailed review of the BACT and/or LAER determinations in a proposed construction permit, you might consider simply requesting in your comments technology which is at least as effective as the technology listed here. If such technology is already required in the permit, then no harm done; if it is not, then the issue will be considered by the permitting authority and preserved for later appeal if necessary.

Finally, it is important to note that technology is ever-evolving, and this summary represents only a snapshot as of the time of publication of this Handbook.[237]

BACT and LAER Technologies for Oil Refineries[238]

Refinery Process Area	BACT-Level Controls	LAER-Level Controls (technology selected depends on pollutant)	Compliance monitoring
1. Refinery Heaters and Boilers	Low NOx burners, Ultra Low-NOx Burners ("UNLBs"), next generation UNLBs, and flue gas recirculation. Enhanced removal of reduced sulfur from refinery fuel gas systems over NSPS requirements. Next generation UNLBs are designed to achieve NO_X emission rates of 0.012-0.020 pounds per million British thermal units ("lbs./mmBTU") of heat input from individual heaters	Ultra Low-NOx Burners ("UNLBs"), next generation UNLBs, flue gas recirculation and selective catalytic reduction / selective non-catalytic reduction. Enhanced removal of reduced sulfur from refinery fuel gas systems over NSPS requirements. Oxidizing catalyst beds for additional CO and VOC control. Next generation UNLBs are designed to achieve NO_X emission rates of 0.012-0.020 pounds per million British thermal units ("lbs./mmBTU") of heat input from individual	Continuous sulfur dioxide emission monitoring on stack discharges or continuous monitoring of hydrogen sulfide equivalents in refinery fuel gases combusted. Care should be taken to ensure that hydrogen sulfide equivalent monitoring measures not only hydrogen sulfide but other total reduced sulfur chemical species found in refinery fuel gas, such as methyl mercaptan. Continuous NOx emission monitoring should be incorporated on all stack discharges.

[237] In order to keep abreast of emerging technology, a useful resource is the "New and Emerging Environmental Technologies" ("NEET") website, operated by RTI International (also known as Research Triangle Institute) with the support of the U.S. EPA, available at http://neet.rti.org/.

[238] *See also*, Appendix B to this Handbook.

	and boilers.	heaters and boilers.	Sources using oxidizing catalysts should incorporate continuous CO emissions monitoring. Recordkeeping and reporting on continuous monitoring device availability; full span incidents and out of control periods should be provided.
2. Waste Flare Gas Systems	Flare gas recovery Compressors / systems; redundant sulfur recovery and tail gas treating process trains; inter-operability between tail gas treating units. Require Shell Claus Off-gas Treatment ("SCOT") train rather than tail gas incinerator or Stretford process unit. Conventional elevated flare; flare gas knock-out pot. Manifold gas collection system for output from pressure operated release valves.	Flare gas recovery Compressors / systems; redundant sulfur recovery and tail gas treating process trains; inter-operability between tail gas treating units. Shell Claus Off-gas Treatment ("SCOT") train rather than tail gas incinerator. Flare gas knock-out pot. Manifold gas collection system for output from pressure-operated release valves. Ground flares and fume incinerators, with elevated refractory lined stack; tip flare incinerators; flare gas knock-out pot.	All incidents of hydrocarbon and acid gas flaring incidents arising from loss of flare gas recovery systems, sulfur recovery unit and tail gas treatment outages and other malfunctions, upsets and planned/unplanned maintenance should be recorded for start/end time, estimated emissions, root cause analysis and remediation for continual improvement. Flare monitoring should feature compliance tests to ensure minimum flare gas Btu content and maximum flare tip velocity, and flare pilot flame presence detection. Flare gas volume metering and closed circuit TV monitoring should be available to the flare operator.

			All ruptured disk incidents and atmospheric releases of vent gas should be recorded and an emissions estimate provided. Tail gas treatment units and tail gas incinerators should have either total reduced sulfur or SO_2 continuous emission monitoring as appropriate. Tail gas incinerators should feature combustion monitoring, including temperature and either O_2 or CO continuous emission monitoring. Recordkeeping and reporting on continuous monitoring device availability, full span incidents and out of control periods should be provided.
3. Fluidized Catalytic Cracker ("FCC") Regeneration Units	High temperature - complete burnout process; electrostatic precipitator PM control, with large fields; catalyst additives for NOx, VOC and CO reduction (*in addition to* – and not as a substitute for) wet scrubbers for SO_2 and selective catalytic reduction ("SCR") for NOx); pre-treat FCC feed for sulfur removal; wet	High temperature - complete burnout process; fabric filter PM control with high temperature bags; catalyst additives for NOx, VOC and CO reduction (*in addition to* – and not as a substitute for – wet scrubbers for SO_2 and selective catalytic reduction ("SCR") for NOx); pre-treat FCC feed for maximum sulfur from feed removal; wet scrubbing after fabric filter control.	Combustion area temperature and O_2 continuous parameter monitoring; continuous NOx, SO_2 and CO emission monitoring. Continuous opacity monitoring and continuous parameter monitoring of the catalyst regeneration rate. Periodic monitoring of the catalytic cracker feed sulfur content. Electrostatic precipitator ("ESP")

	scrubbing.		controlled units should require monitoring of the primary ESP input power and secondary ESP voltage. All ESP outages caused by excessive CO in the unit should be recorded. Recordkeeping and reporting on continuous monitoring device availability, full span incidents and out of control periods should be provided.
4. Fugitive Emissions	Gas collection manifold systems for all miscellaneous process vents; bellows valves; enhanced valve packing; low threshold on leak detection and repair detection down to 500 parts per million ("ppm") VOC. Monthly monitoring of all heat exchanger water directed to cooling towers for VOC content.	Gas collection manifold systems for all miscellaneous process vents; bellows valves; enhanced valve packing; low threshold on leak detection and repair detection below 500 ppm VOC. Monthly monitoring of all heat exchanger water directed to cooling towers for VOC content. Enhanced metallurgy for heat exchanger for corrosion and degradation resistance.	Quarterly reporting of the leak detection rate; tracking of repaired and un-repaired leaks until refinery turnaround components are installed. New optical scanning leak detection monitoring may offer advantages over traditional VOC detection unit monitoring. Daily monitoring of VOC content of refinery cooling water systems.
5. Product Loading Racks and Marine Terminals	Condensation vapor recovery systems or thermal oxidizer VOC / HAP control with low NOx burners. All tanker trucks to be tested annually	Thermal oxidizer VOC / HAP control with ultra low NOx burners, flue gas recirculation and vapor recovery system for all process off-gas. All tanker trucks to be tested annually for leaks	Continuous combustion parameter monitoring for temperature and O_2 at the exit of the combustion chamber. Compliance verification after construction of all

	for leaks before loading can be allowed.	before loading can be allowed.	emission rates. Loading racks using flares (*see* monitoring requirements for waste flare gas systems, above). Require all trucks and rail cars to provide evidence of a recent leak test.
6. Wastewater Management Units	Sealed sewer system with vapors vented to a thermal oxidizer; API oil-water separators and diffused air floatation units vented to a thermal oxidizer. The permit should specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions.	Sealed sewer system with vapors vented to a thermal oxidizer; API oil-water separators and diffused air floatation units vented to a thermal oxidizer; ultra low NOx burner for incinerator. The permit should specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions.	Visual monitoring on a weekly basis for the presence of water seals. Continuous combustion parameter monitoring for temperature and O_2 at the exit of the combustion chamber. Compliance verification of all emission rates after construction.
7. Catalytic Refining Catalyst Regeneration Operation	Wet scrubbing; good combustion conditions.	Wet scrubbing; good combustion conditions; thermal oxidizer flue gas after-treatment.	Continuous monitoring of scrubber flow rate, pressure drop, scrubber makeup water availability, exhaust temperature, caustic or other scrubber water addition; continuous combustion parameter monitoring for temperature and O_2 at

			the exit of the combustion chamber. Compliance verification of all emission rates after construction.
8. Internal and External Floating Roof Tanks	Work practice standards for inspections to maintain integrity of tank seals.	Work practice standards for inspections to maintain integrity of tank seals; increased frequency of inspections over NSPS requirements.	Annual visible inspections of tanks, including verification of tank seal integrity. Monthly brief visual inspections of floating roofs to determine that no liquids have breached seal to the tops of floating roofs and that precipitation drainage systems are working properly.
9. Wastewater Treatment Plant Filter Press Sludge Incinerator	High energy wet scrubber.	High energy wet scrubber; fabric filter spray dryer; waste gasification.	Continuous monitoring of scrubber flow rate, pressure drop, scrubber makeup water availability, exhaust temperature, caustic or other scrubber water addition; opacity monitor; continuous combustion temperature and O_2 monitor.
10. Petroleum Coke Handling	Work practice standards to control coke drum opening for VOC control; covered conveyors with wet spray; coke pile water spray control; enclosure of coking process (*i.e.*, not on open pads); monitoring of VOC / benzene and "coke	Work practice standards to control coke drum opening for VOC control; covered conveyors with wet spray and fabric filter control; silo storage controlled by fabric filter; enclosure of coking process (*i.e.*, not on open pads); monitoring of VOC/benzene and "coke fine" emissions using portable analyzers.	Verification and recordkeeping regarding work practices and water sprays; verification and recordkeeping regarding housekeeping and best management practices.

	fine" emissions using portable analyzers.		

11. Monitoring

As a final point regarding monitoring for any of the processes above, you should request "continuous emission monitoring systems ("CEMS").[239] As noted above, CEMS are the best monitoring systems, and perform "a direct measurement of pollutant concentration from a duct or stack on a continuous or periodic basis."[240] "Continuous opacity monitoring systems" ("COMS") are a subset of CEMS, which measure opacity (an indicator of particulate matter emissions).[241] For a detailed description of available CEMS and COMS, *see* EPA document EPA/452/B-02-001, "EPA Emission Control Cost Manual," section 2, chapter 4, available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf, and EPA's Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/ (click on both "monitoring" and "methods"). In addition, for "opacity" of stack emissions, you should request continuous video monitoring, and for emissions of other pollutants (both "stack" and "fugitive"), you should request "Fourier Transformation Infrared Spectroscopy" ("FTIR").[242] Finally, an important new technology to keep in mind, especially for LDAR, is "differential light absorption lidar" ("DIAL"), which, compared with emission factor estimates, has been found to detect 33

[239] For an overview of monitoring methods, *see* EPA's Technology Transfer Network – Emission Measurement Center at http://www.epa.gov/ttn/emc/ (click on both "monitoring" and "methods").

[240] EPA Cost Manual, *supra* note 141, at 4.3.

[241] At the time of publication of this Handbook, the EPA is proposing to overhaul the NSPS applicable to oil refineries. *See* Proposed Standards of Performance for Petroleum Refineries, 72 Fed. Reg. 27178 (May 14, 2007) (to be codified at 40 C.F.R. Part 60, subparts J and Ja), *available at* http://a257.g.akamaitech.net/7/257/2422/01jan20071800/edocket.access.gpo.gov/2007/pdf/E7-8547.pdf. The proposed rule would omit an opacity standard for FCCUs because more effective PM CEMS are available to directly monitor PM, rather than monitoring opacity as a surrogate for PM emissions. 72 Fed. Reg. at 27191. The Environmental Integrity Project, together with the Sierra Club, has submitted comments to the proposed refinery NSPS arguing that a monitored opacity limit is still necessary, *along with* CEMS for PM. Those comments are available at http://www.environmentalintegrity.org/pub462.cfm.

[242] The EPA explains: "The FTIR technology … has the capability to measure more than 100 of the 189 Hazardous Air Pollutants (HAPs) listed in Title III of the Clean Air Act Amendments of 1990 (CAAA). Upon passage of the CAAA, measurement methods existed for only 40 of the HAPs. The FTIR has the capability of measuring multiple compounds simultaneously, thus providing an advantage over current measurement methods which measure only one or several HAPs; *FTIR can provide a distinct cost advantage* since it can be used to replace several traditional methods (cost savings can vary depending on the number of compounds present)." EPA Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/monitor.html#ftir (emphases added). *See also*, EPA Cost Manual, *supra* note 141, at 4.10: "[FTIR] detects compounds based on the absorption of infrared light at critical wavelengths. … Current FTIR CEMs can accurately monitor up to six gaseous compounds (SO_2, NO_x, CO, HCl, CO_2, and O_2), various hazardous air pollutants, and volatile organic compounds simultaneously. … Although FTIR instruments tend to be more expensive than other analyzers, the ability to monitor multiple pollutants with one instrument improves its cost effectiveness."

times more VOC and *96 times more benzene* (a known carcinogen) from storage emissions, and 12 times more VOC and 8 times more benzene from fugitive emissions.[243]

Conclusion

The combination of high gasoline prices and increasing demand for oil has resulted in record profits for oil companies. To capitalize on this lucrative market, refiners are increasing production and expanding their existing refineries, many of which are located in areas that already do not meet federal air quality standards set to protect public health and the environment. Meanwhile, many lawmakers and Administration officials have attempted to blame higher gasoline prices on an alleged "shortage" of refining capacity in order to justify rolling back air quality protections so that refiners can increase capacity even more quickly.

Paying the price for the country's increased refining capacity, the predominantly low-income and minority communities living near expanding refineries face an increase in toxic air pollution, the hazards of which include premature death; cancer; respiratory illness; aggravation of heart conditions and asthma; permanent lung damage; reproductive, neurological, developmental, respiratory, and immunological problems; bio-mutations; cardiovascular and central nervous system problems; subjugation to noise and foul odors; and periodic requirements to remain indoors until winds carry toxic pollution away. Further, the damage to the environment caused by oil refinery pollution – in fenceline communities and well beyond – includes global warming; acid rain; concentration of toxic chemicals up the food chain; the creation of ground level ozone and smog; visible impairments that migrate to sensitive areas such as National Parks; and the depletion of soil nutrients. Further, oil refiners are already gearing up to process the "tar sands" of Alberta, Canada, which heralds the utter sacking of the vast Canadian boreal forest ecosystem and a significant increase of greenhouse gas emissions into the atmosphere.

Clean Air Act permits given to oil refineries are *permits to pollute* the air that we all take into our lungs to live. These permits are granted by our government on our behalf. Participation in the permitting of oil refineries is the right of every citizen, and effective participation makes a real difference in the quality and stringency of the permits under which refineries must operate, the quality of life for those bearing the burden of sharing their neighborhoods with oil refineries, and ultimately, and the health of our global environment.

Participation in the process can be a daunting challenge. The legal processes are complex and the issues are often highly technical. However, the permitting authorities must consider your input, and the very act of commenting lets both the refineries and the government know that *someone is watching*. Your participation in the process makes an enormous difference.

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[243] DIAL Study, *supra* note 156, at 17-18.

APPENDIX A

Summary of Issues and Comments for NSR Permits

I. Determining NSR Applicability

- Facilities will do almost anything to avoid New Source Review, by either claiming that they have not had a "major" modification, or that they are "netting out" of emission increases. The latter is more likely where large projects are involved, although you should also watch for "sham minor modifications" which attempt to split major modifications into multiple "minor" modifications. The problem of refineries attempting to avoid NSR altogether by "splitting" or "netting" is one of the most important issues to watch for when reviewing a proposed permit.

- Intentionally splitting what is in reality a single modification project into smaller projects ("sham" minor modifications) in order to avoid triggering the NSR program is illegal. Where the projects are proposed within a short time, and the changes could be considered part of a single project, such an illegal "splitting" may have occurred. Whether "minor modification" claims are simply in error, or are outright attempts to evade major modification review, you should watch for majors in minor clothing.

- States are no longer allowed to let industry substantially increase one pollutant (*e.g.*, carbon monoxide) in an effort to control another pollutant (*e.g.*, nitrogen oxide); that is, there is no longer a "pollution control" exception, as EPA attempted to promulgate in 2002.

- "Netting" to avoid NSR is currently perhaps the biggest loophole for oil refineries. As you review proposed permits, you should keep in mind the following points:

  1) Any decreases claimed for netting purposes must be "contemporaneous" and "creditable" (and must be "federally and practically enforceable" to be "creditable").

  2) The refinery should not get credit for any reductions it made in the past (or is making simultaneously) that were made because they were required by rules or consent decrees. Further, to be "creditable," the recent decrease must not have been previously relied upon by the permitting authority in issuing an NA NSR or

PSD permit to the facility. Also, any voluntary reductions the facility made or plans to make have to be made enforceable.

3) You should question how any emission reductions from netting are going to be monitored and enforced. For example, if a refinery is claiming reductions from reducing fugitives (*e.g.*, through better leak detection), your comments should point out that these emission reductions are very hard to monitor and enforce and demand excellent monitoring for any fugitives that are claimed as netting credits. A good monitoring technology is "Fourier Transformation Infrared Spectroscopy" ("FTIR").

4) Although EPA rules allow refineries to estimate future emissions based on "projected actual" emissions, some states have not accepted that rule, and still base emissions increases on "potential to emit" ("PTE"). You should insist that the refinery be enforceably limited to its projected actual emission increases, if your state SIP allows it.

II. Monitoring, Recordkeeping, and Reporting

- The monitoring requirements in the permit must be "practically enforceable." "Practical enforceability" requires that the monitoring provisions:

  1) are unambiguous;

  2) are accompanied by unambiguous recordkeeping and reporting requirements;

  3) do not limit the use of "credible evidence" in demonstrating non-compliance; and

  4) do not allow non-compliance. Two scenarios of improperly permitted non-compliance to watch for are:

     a) where satisfaction of a permit requirement is left to the discretion of the director of the permitting authority, rather than determined by achievement of specific criteria ("Director's discretion"); and

     b) where the permit excuses emissions in excess of permitted limits during times of startup / shutdown, maintenance, and/or malfunction.

- The permit should clearly state: 1) what records must be kept; 2) how long the records must be kept;[244] 3) what the facility must report; 4) to whom the facility must report; 5) how the facility must report (*e.g.*, electronically or otherwise); and 6) how frequently the facility must report. Some records that the permit should require be kept on-site and also submitted to the permitting authority include: 1) the name and location of each processing unit tested and/or monitored; 2) the dates and times of testing and/or monitoring; 3) the test method, instrument calibration, or other quality assurance ("QA") information; 4) the monitoring and/or testing results; and 5) the date and description of leak corrections and follow-up.[245]

- If a facility uses Predictive Emission Monitoring Systems ("PEMS," sometimes called "parametric" or "surrogate" monitoring), the permit should require that the facility demonstrate the correlation between the measured parameter and the regulated pollutant,[246] and that the facility periodically verify this correlation using direct measurement, such as a stack test.[247]

- A refinery's "leak detection and repair ("LDAR") program should be a "directed" program (follow-up testing is done to make sure that the leak is fixed) rather than "non-directed" (no follow-up testing is done), and should clearly require repairs within a short and specific timeframe, using mandatory rather than permissive language (*e.g.*, "all leaks shall be repaired within fifteen days," rather than "every effort will be made to repair leaks as soon as possible").[248]

- For "opacity" of stack emissions, you should request continuous video monitoring, and for emissions of other pollutants (both "stack" and "fugitive"), you should request "Fourier Transformation Infrared Spectroscopy" ("FTIR").[249]

[244] In order to comply with Title V permit regulations, all records must be kept for *at least* five years.

[245] *See* ABCs of NSR, *supra* note 26, at 89-90. *See also*, Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" at 2-3 (Jan. 26, 2003).

[246] EPA Cost Manual, *supra* note 141, at 4.3.

[247] *Id*. at 4.14.

[248] Brandt Mannchen, Houston Sierra Club, "Testing and Monitoring in New Source Review Permits" at 2 (Jan. 26, 2003).

[249] The EPA explains: "The FTIR technology … has the capability to measure more than 100 of the 189 Hazardous Air Pollutants (HAPs) listed in Title III of the Clean Air Act Amendments of 1990 (CAAA). Upon passage of the CAAA, measurement methods existed for only 40 of the HAPs. The FTIR has the capability of measuring multiple compounds simultaneously, thus providing an advantage over current measurement methods which measure only one or several HAPs; *FTIR can provide a distinct cost advantage* since it can be used to replace several traditional methods (cost savings can vary depending on the number of compounds present)." EPA Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/monitor.html#ftir (emphases added). *See also*, EPA Cost Manual,

- An important new technology to keep in mind, especially for LDAR, is "differential light absorption and ranging" ("DIAL"),[250] which, compared with emission factor estimates, has been found to detect 33 times more VOC and *96 times more benzene* (a known carcinogen) from storage emissions, and 12 times more VOC and 8 times more benzene from fugitive emissions.[251]

III. Startup, Shutdown and Maintenance ("SSM") and Malfunctions ("upsets")

- If you find any "excess emissions provisions" in a proposed permit which allow emissions in excess of permit limits during times of SSM or upsets, your comments should insist:

    1) that SSM provisions apply only when it is "technologically impossible" for the refinery to comply with the limits, and where the emissions are short and infrequent, could not have been prevented through careful planning and design, and are not part of a recurring pattern;

    2) that upset provisions apply only when it is "beyond the refinery's control" to stay within limits, and where the excess emissions are caused by a sudden, unavoidable breakdown of technology, do not stem from anything that could have been foreseen, planned for, or avoided by better operation and maintenance, and are not part of a recurring pattern;

    3) that the provisions be removed from the permit if they "excuse emissions that should be under the refinery's control" or allow for "Director's discretion;"

    4) that the provisions comply with all of the requirements set forth in the EPA's "Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown," available at

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supra note 141, at 4.10: "[FTIR] detects compounds based on the absorption of infrared light at critical wavelengths. … Current FTIR CEMs can accurately monitor up to six gaseous compounds (SO_2, NO_x, CO, HCl, CO_2, and O_2), various hazardous air pollutants, and volatile organic compounds simultaneously. … Although FTIR instruments tend to be more expensive than other analyzers, the ability to monitor multiple pollutants with one instrument improves its cost effectiveness."

[250] The acronym "DIAL" stands for "Differential Absorption LIDAR," and "LIDAR" stands for "Light Detection and Ranging."

[251] Allan Chambers, P.Eng. and Mel Strosher, "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection," (Alberta Research Council, March 31, 2006 – revised November 1, 2006) at iv, *available at* http://www.arc.ab.ca/ARC-Admin/UploadedDocs/Dial%20Final%20Report%20Nov06.pdf.

http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/excesem2.pdf;

5) that the permit require adequate monitoring of "excess emissions" (both SSM and upsets), such as continuous video monitoring for opacity and "Fourier Transformation Infrared Spectroscopy" ("FTIR") for other emissions;

6) that where state rules allow an affirmative defense, the scope should be as narrow as possible (affirmative defenses must not be made available for injunctive relief, so permits should make clear that the problem must be fixed, and "automatic exemptions" are not allowed), and that refineries should not get any affirmative defense for repeat violations;

7) that refineries be required to promptly report excess emissions and take steps to prevent recurrence;

8) that under no circumstance should emissions during SSM or upset events be treated as "exempt" from the Clean Air Act;

9) that the permit require electronic reporting of all excess emissions within 24 hours (toxics reported immediately), and that the reports be made available to the public on state agency websites within 72 hours; and

10) that permits provide for automatic penalties for upsets, require offset reductions in routine emissions, require facilities to shut down after a certain number of excess emission events, and including excess emissions in PTE calculations.

IV. Environmental Justice

- When environmental justice issues are raised, the U.S. EPA or the state with delegated permitting authority must conduct an environmental justice analysis to determine whether the refinery expansion will have a disproportionate effect on minority and low-income communities.

V. Class I Area Impacts

- If you believe that a major new source refinery or modification will adversely impact a Class I area (such as a Wilderness Area or National Wildlife Refuge), *even if* the project is more than 10 kilometers from the Class I area, you should include those concerns in your comments to the permitting authority, and also notify the appropriate Federal Land

Manager ("FLM") (and refuge manager in the case of wildlife refuges).[252] In the case of a PSD permit, the FLM should review the permit to evaluate impacts to air quality related values ("AQRVs"), and in the case of an NA NSR permit, the FLM should review the permit for visibility impacts. In either case, the FLM should make recommendations on the permit based on the FLM's duty to protect such values.

VI. PSD Permit Issues

- Best Available Control Technology ("BACT") determination

    - Regarding the BACT determination, the EPA has explained: "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review."[253] If such "clear documentation" does not appear, you should challenge the proposed permit on that basis.

    - Perhaps the best way to determine BACT is to find out what technology and limits have been required for other refineries in the recent past, [254] especially by your permitting authority.[255] Your

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[252] "Mandatory" "Class I areas" include International Parks; National Wilderness Areas (including certain National Wildlife Refuges, National Monuments, and National Seashores) in excess of 5,000 acres; National Memorial Parks in excess of 5,000 acres; and National Parks in excess of 6,000 acres, all of which were in existence on August 7, 1977. 40 C.F.R. § 52.21(e)(1). However, other areas may be designated as "Class I areas." For a list of "Mandatory Class I Areas," and their corresponding Federal Land Managers ("FLMs"), *see* EPA NSR Workshop Manual, *supra* note 35, at E.3 – E.6, reproduced as Appendix I to this Handbook.

[253] EPA's NSR Workshop Manual, *supra* note 35, at B.6.

[254] The EPA's "RACT / BACT /LAER Clearinghouse" ("RBLC") contains case-specific examples of actual BACT determinations submitted by state and local permitting authorities, as well as links to other resources, although the RBLC is typically 3-4 years out of date. The RBLC is available at http://cfpub1.epa.gov/rblc/htm/bl02.cfm. Also, although the EPA proposed in March of 2007 to remove petroleum refining from the triennial "National Enforcement Priorities" for FY 2008-2010, the previous "Refinery Enforcement Initiative" resulted in 18 consent decrees with refining companies since 2000, which are available at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/ (you can check to find the latest consent decrees at http://cfpub.epa.gov/compliance/cases/index.cfm). In addition, the State of California, which generally has stringent BACT requirements (in fact, California's BACT is sometimes considered LAER since much of the State is in non-attainment), maintains a statewide BACT clearinghouse at http://www.arb.ca.gov/bact/bact.htm. Also, although now somewhat out of date, the U.S. EPA in 2001 issued a memorandum regarding "BACT and LAER for Emission of [NOx] and [VOCs] at Tier 2/Gasoline Sulfur Refinery Projects," memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to all U.S. EPA Regional Air Division Directors (Jan. 19, 2001), *available at* http://epa.gov/region7/programs/artd/air/nsr/nsrmemos/t2bact.pdf. Another resource for actual examples of innovative monitoring is http://www.zerowastenetwork.org/success/index.cfm. It should also be noted that technology is ever-evolving, and this summary represents only a snapshot as of the time of publication of this Handbook. In order to keep abreast of emerging technology, a useful resource is the "New and

comments should highlight any instances in which the permitting authority has previously required more stringent BACT limits and request an explanation for the inconsistency.

- The air quality impact analysis contained in a PSD permit application must demonstrate that new emissions from the project, *in conjunction with all potential emissions from other sources in the attainment area, and including secondary emissions from the project*, will not result in a violation of any NAAQS or PSD increment. To this end, the PSD permit application should include a "source inventory" (sometimes called an "emissions inventory").

    - The allowable increment is based on the baseline concentration, which is essentially the amount of the pollutant already in the air when the first complete PSD permit application affecting the area was submitted. You should ensure that the calculation of the baseline concentration is adequately documented. In particular, any assumptions in lieu of actual monitoring data must be fully explained.

    - You should ensure that all other sources and secondary emissions[256] are included.

    - You should ensure that the inventory considers total *permitted* (or "potential") emissions, rather than *actual* emissions, in determining whether a *NAAQS* violation could occur,[257] (although EPA policy allows the use of actual emissions in determining whether a *PSD increment* violation could occur).

- For specific BACT technologies, *see* Appendix B

Emerging Environmental Technologies" ("NEET") website operated by RTI International (also known as Research Triangle Institute) with the support of the U.S. EPA, available at http://neet.rti.org/.

[255] One way to do this is to compare the most recent construction permits for other refineries in your state. You can find other refineries in your state at http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2004/pdf/table_38.pdf. Once you know the other refineries, you might be able to find their construction permits on your permitting authority's website. If not, and if the permitting authority will not provide them in response to an informal request, then you can obtain them through a Freedom of Information Act ("FOIA") request.

[256] "Secondary emissions" can be found in the "additional impacts analysis – growth" portion of the PSD permit application.

[257] The emission limits in the permit (or total "potential" emissions) should be higher than actual emissions. In any event, unless permit violations are occurring, actual emissions should never be higher than the permitted emissions.

VII. NA NSR Permit Issues

- Emissions Reductions / Offsets

  - Offsets must be creditable, quantifiable, federally enforceable, and permanent.

  - To be "creditable," the offsets must not have resulted from some other regulatory action. This includes reductions already required by a SIP, and any reductions already counted for "netting" purposes.

  - Where a refinery has in the past obtained a construction permit for an emissions unit which was never actually operated, the facility cannot claim "decreased" reductions from such a unit. Similarly, where the permit allows an emissions unit to emit more than it actually emits, the source cannot claim the "permit limit" as the "offset" by shutting down the unit. Rather, the source can only claim the *actual* historical emissions. The difference is commonly called a "paper reduction" and is not permissible.

  - The EPA has stated that "offsets should be located as close to the proposed site as possible" and generally "within the same air quality control region."[258] However, you may argue that principles of environmental justice dictate that the emission reductions come from sources in the same community as the new emission increases.

- Demonstration of compliance

  - An applicant for an NA NSR permit must certify that all other major stationary sources it owns or operates in the state are in compliance with all applicable provisions of the CAA. Your state's permitting authority should be able to tell you whether the refiner owns or operates other facilities in the state, or else that information might be on the agency's website. If the other facilities are not in compliance with the CAA and have no plan to come into compliance, then the state *cannot issue an NA NSR permit* (and, in some states, cannot issue a PSD permit). A useful resource in this regard is the U.S. EPA's online database, "Enforcement and Compliance History Online" ("ECHO"), available at http://www.epa.gov/Compliance/data/systems/multimedia/echo.html.

[258] EPA's NSR Workshop Manual, *supra* note 35, at G.6.

- Alternatives Analysis

    - Section 173(a)(5) of the CAA, 42 U.S.C. § 7503(a)(5), requires that NA NSR permits be issued only if "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification." You should review the NA NSR permit application to ensure that an alternatives analysis has been done. If it has not been done, then *the permit should not be issued*. If the alternatives analysis has been done, then you should review it to ensure that it is adequate. In commenting on the analysis, you should raise any environmental justice concerns which you believe have not been adequately addressed.

- For specific lowest achievable emission rate ("LAER") technologies, *see* Appendix B

VIII. Other Specific Points to Raise

- Your comments should ask that the coking operation be fully enclosed to prevent the dispersal of coke dust when coke is periodically removed from drums; that emissions of benzene and VOCs be monitored (*e.g.*, using portable analyzers); and that the permitting authority prohibit the use of wastewater in the quenching process.

- Your comments should ask what the formaldehyde emissions are, how the refinery monitors or estimates the formaldehyde emissions, and whether the refinery is reporting formaldehyde emissions.

- The EPA has found that, historically, refineries have substantially underestimated their emissions of NO_x from heaters and boilers. New and existing heaters and boilers should be equipped with continuous emission monitors that measure emissions of NO_x and other contaminants.

- Your comments should ask that the permit specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions.

- Sulfur recovery units ("SRUs") need to expand to keep pace with increases in the production capacity of catalytic crackers and other units at the front end of refineries, or else the refinery will be overwhelmed with sulfur-rich waste streams that end up being released to the environment.

SRUs should have some "redundant" capacity to handle sudden spikes in the sulfur content of waste streams.

- Your comments should ask how emissions from flares are estimated, and insist that any emissions be promptly reported.

- Fugitive emissions are often chronically underestimated because they are so infrequently and poorly monitored. Your comments should insist that the permit require state of the art monitoring for such emissions by, for example, requiring the use of "Fourier Transformation Infrared Spectroscopy" ("FTIR").

- Fugitive emissions from storage tanks should be controlled. A failure to properly control emissions from storage tanks is a serious matter. For example, Citgo Petroleum Corporation was convicted on June 27, 2007 on two felony violations of the Clean Air Act for operating storage tanks at its Corpus Christi, Texas refinery without fixed or floating roofs, such that the company faces fines up to $500,000 per count or twice the economic gain (whichever is higher), and five years of probation.[259]

[259] *See* U.S. Department of Justice news release, "Citgo Petroleum and Subsidiary Found Guilty of Environmental Crimes," June 27, 2007, *available at* http://www.usdoj.gov/opa/pr/2007/June/07_enrd_463.html.

APPENDIX B

BACT and LAER Technologies for Oil Refineries[260]

Refinery Process Area	BACT-Level Controls	LAER-Level Controls (technology selected depends on pollutant)	Compliance monitoring
1. Refinery Heaters and Boilers	Low NOx burners, Ultra Low-NOx Burners (“UNLBs”), next generation UNLBs, and flue gas recirculation. Enhanced removal of reduced sulfur from refinery fuel gas systems over NSPS requirements. Next generation	Ultra Low-NOx Burners (“UNLBs”), next generation UNLBs, flue gas recirculation and selective catalytic reduction / selective non-catalytic reduction. Enhanced removal of reduced sulfur from refinery fuel gas systems over NSPS requirements. Oxidizing catalyst beds for additional CO and	Continuous sulfur dioxide emission monitoring on stack discharges or continuous monitoring of hydrogen sulfide equivalents in refinery fuel gases combusted. Care should be taken to ensure that hydrogen sulfide equivalent monitoring measures not only hydrogen sulfide but other total reduced sulfur chemical

[260] This summary is based on a review of past BACT and LAER determinations, EPA consent decrees with refineries, EPA and other agency guidance, websites of technology vendors, and the advice of technical experts. The EPA’s “RACT / BACT /LAER Clearinghouse” (“RBLC”) contains case-specific examples of actual BACT determinations submitted by state and local permitting authorities, as well as links to other resources, although the RBLC is typically 3-4 years out of date. The RBLC is available at http://cfpub1.epa.gov/rblc/htm/bl02.cfm. Also, although the EPA proposed in March, 2007 to remove petroleum refining from the triennial “National Enforcement Priorities” for FY 2008-2010, the previous “Refinery Enforcement Initiative” resulted in 18 consent decrees with refining companies since 2000, which are available at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/ (you can check to find the latest consent decrees at http://cfpub.epa.gov/compliance/cases/index.cfm). In addition, the State of California, which generally has stringent BACT requirements (in fact, California’s BACT is sometimes considered LAER since much of the State is in non-attainment), maintains a statewide BACT clearinghouse at http://www.arb.ca.gov/bact/bact.htm. Also, although now somewhat out of date, the U.S. EPA in 2001 issued a memorandum regarding “BACT and LAER for Emission of [NOx] and [VOCs] at Tier 2/Gasoline Sulfur Refinery Projects,” memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to all U.S. EPA Regional Air Division Directors (Jan. 19, 2001), *available at* http://epa.gov/region7/programs/artd/air/nsr/nsrmemos/t2bact.pdf. Another resource for actual examples of innovative monitoring is http://www.zerowastenetwork.org/success/index.cfm. It should also be noted that technology is ever-evolving, and this summary represents only a snapshot as of the time of publication of this Handbook. In order to keep abreast of emerging technology, a useful resource is the “New and Emerging Environmental Technologies” (“NEET”) website operated by RTI International (also known as Research Triangle Institute) with the support of the U.S. EPA, available at http://neet.rti.org/.

	UNLBs are designed to achieve NO_X emission rates of 0.012-0.020 pounds per million British thermal units (“lbs./mmBTU”) of heat input from individual heaters and boilers.	VOC control. Next generation UNLBs are designed to achieve NO_X emission rates of 0.012-0.020 pounds per million British thermal units (“lbs./mmBTU”) of heat input from individual heaters and boilers.	species found in refinery fuel gas, such as methyl mercaptan. Continuous NOx emission monitoring should be incorporated on all stack discharges. Sources using oxidizing catalysts should incorporate continuous CO emissions monitoring. Recordkeeping and reporting on continuous monitoring device availability; full span incidents and out of control periods should be provided.
2. Waste Flare Gas Systems	Flare gas recovery Compressors / systems; redundant sulfur recovery and tail gas treating process trains; inter-operability between tail gas treating units. Require Shell Claus Offgas Treatment (“SCOT”) train rather than tail gas incinerator or Stretford process unit. Conventional elevated flare; flare gas knock-out pot. Manifold gas collection system for output from pressure operated release valves.	Flare gas recovery Compressors / systems; redundant sulfur recovery and tail gas treating process trains; inter-operability between tail gas treating units. Shell Claus Offgas Treatment (“SCOT”) train rather than tail gas incinerator. Flare gas knock-out pot. Manifold gas collection system for output from pressure-operated release valves. Ground flares and fume incinerators, with elevated refractory lined stack; tip flare incinerators; flare gas knock-out pot.	All incidents of hydrocarbon and acid gas flaring incidents arising from loss of flare gas recovery systems, sulfur recovery unit and tail gas treatment outages and other malfunctions, upsets and planned/unplanned maintenance should be recorded for start/end time, estimated emissions, root cause analysis and remediation for continual improvement. Flare monitoring should feature compliance tests to ensure minimum flare gas Btu content and maximum flare tip

			velocity, and flare pilot flame presence detection. Flare gas volume metering and closed circuit TV monitoring should be available to the flare operator. All ruptured disk incidents and atmospheric releases of vent gas should be recorded and an emissions estimate provided. Tail gas treatment units and tail gas incinerators should have either total reduced sulfur or SO_2 continuous emission monitoring as appropriate. Tail gas incinerators should feature combustion monitoring, including temperature and either O_2 or CO continuous emission monitoring. Recordkeeping and reporting on continuous monitoring device availability, full span incidents and out of control periods should be provided.
3. Fluidized Catalytic Cracker ("FCC") Regeneration Units	High temperature - complete burnout process; electrostatic precipitator PM control, with large fields; catalyst additives for NOx, VOC and CO reduction (*in*	High temperature - complete burnout process; fabric filter PM control with high temperature bags; catalyst additives for NOx, VOC and CO reduction (*in addition to* – and not as a substitute for – wet scrubbers for SO_2 and selective catalytic	Combustion area temperature and O_2 continuous parameter monitoring; continuous NOx, SO_2 and CO emission monitoring. Continuous opacity monitoring and continuous parameter

	addition to – and not as a substitute for) wet scrubbers for SO_2 and selective catalytic reduction (“SCR”) for NOx); pre-treat FCC feed for sulfur removal; wet scrubbing.	reduction (“SCR”) for NOx); pre-treat FCC feed for maximum sulfur from feed removal; wet scrubbing after fabric filter control.	monitoring of the catalyst regeneration rate. Periodic monitoring of the catalytic cracker feed sulfur content. Electrostatic precipitator (“ESP”) controlled units should require monitoring of the primary ESP input power and secondary ESP voltage. All ESP outages caused by excessive CO in the unit should be recorded. Recordkeeping and reporting on continuous monitoring device availability, full span incidents and out of control periods should be provided.
4. Fugitive Emissions	Gas collection manifold systems for all miscellaneous process vents; bellows valves; enhanced valve packing; low threshold on leak detection and repair detection down to 500 parts per million (“ppm”) VOC. Monthly monitoring of all heat exchanger water directed to cooling towers for VOC content.	Gas collection manifold systems for all miscellaneous process vents; bellows valves; enhanced valve packing; low threshold on leak detection and repair detection below 500 ppm VOC. Monthly monitoring of all heat exchanger water directed to cooling towers for VOC content. Enhanced metallurgy for heat exchanger for corrosion and degradation resistance.	Quarterly reporting of the leak detection rate; tracking of repaired and un-repaired leaks until refinery turnaround components are installed. New optical scanning leak detection monitoring may offer advantages over traditional VOC detection unit monitoring. Daily monitoring of VOC content of refinery cooling water systems.

5. Product Loading Racks and Marine Terminals	Condensation vapor recovery systems or thermal oxidizer VOC / HAP control with low NOx burners. All tanker trucks to be tested annually for leaks before loading can be allowed.	Thermal oxidizer VOC / HAP control with ultra low NOx burners, flue gas recirculation and vapor recovery system for all process off-gas. All tanker trucks to be tested annually for leaks before loading can be allowed.	Continuous combustion parameter monitoring for temperature and O_2 at the exit of the combustion chamber. Compliance verification after construction of all emission rates. Loading racks using flares (*see* monitoring requirements for waste flare gas systems, above). Require all trucks and rail cars to provide evidence of a recent leak test.
6. Wastewater Management Units	Sealed sewer system with vapors vented to a thermal oxidizer; API oil-water separators and diffused air floatation units vented to a thermal oxidizer. The permit should specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions.	Sealed sewer system with vapors vented to a thermal oxidizer; API oil-water separators and diffused air floatation units vented to a thermal oxidizer; ultra low NOx burner for incinerator. The permit should specifically identify the waste streams that will be measured for benzene content, specify the method that will be used to estimate emissions, and require regular reporting of such emissions.	Visual monitoring on a weekly basis for the presence of water seals. Continuous combustion parameter monitoring for temperature and O_2 at the exit of the combustion chamber. Compliance verification of all emission rates after construction.
7. Catalytic Refining Catalyst	Wet scrubbing; good combustion conditions.	Wet scrubbing; good combustion conditions; thermal oxidizer flue gas	Continuous monitoring of scrubber flow rate, pressure

Regeneration Operation		after-treatment.	drop, scrubber makeup water availability, exhaust temperature, caustic or other scrubber water addition; continuous combustion parameter monitoring for temperature and O_2 at the exit of the combustion chamber. Compliance verification of all emission rates after construction.
8. Internal and External Floating Roof Tanks	Work practice standards for inspections to maintain integrity of tank seals.	Work practice standards for inspections to maintain integrity of tank seals; increased frequency of inspections over NSPS requirements.	Annual visible inspections of tanks, including verification of tank seal integrity. Monthly brief visual inspections of floating roofs to determine that no liquids have breached seal to the tops of floating roofs and that precipitation drainage systems are working properly.
9. Wastewater Treatment Plant Filter Press Sludge Incinerator	High energy wet scrubber.	High energy wet scrubber; fabric filter spray dryer; waste gasification.	Continuous monitoring of scrubber flow rate, pressure drop, scrubber makeup water availability, exhaust temperature, caustic or other scrubber water addition; opacity monitor; continuous combustion temperature and O_2 monitor.
10. Petroleum Coke Handling	Work practice standards to control coke drum opening for VOC control;	Work practice standards to control coke drum opening for VOC control; covered conveyors with	Verification and recordkeeping regarding work practices and water

	covered conveyors with wet spray; coke pile water spray control; enclosure of coking process (*i.e.*, not on open pads); monitoring of VOC / benzene and "coke fine" emissions using portable analyzers.	wet spray and fabric filter control; silo storage controlled by fabric filter; enclosure of coking process (*i.e.*, not on open pads); monitoring of VOC/benzene and "coke fine" emissions using portable analyzers.	sprays; verification and recordkeeping regarding housekeeping and best management practices.

Monitoring

As a final point regarding monitoring for any of the processes above, you should request "continuous emission monitoring systems ("CEMS"). CEMS are the best monitoring systems, and directly measure pollutant concentrations from an emissions point (such as a stack) on a continuous basis. "Continuous opacity monitoring systems" ("COMS") are a subset of CEMS which measure opacity (an indicator of particulate matter emissions). For a detailed description of available CEMS and COMS, *see* EPA document EPA/452/B-02-001, "EPA Emission Control Cost Manual," section 2, chapter 4, available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf, and EPA's Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/ (click on both "monitoring" and "methods"). In addition, for "opacity" of stack emissions, you should request continuous video monitoring, and for emissions of other pollutants (both "stack" and "fugitive"), you should request "Fourier Transformation Infrared Spectroscopy" ("FTIR").[261] Finally, an important new technology to keep in mind, especially for LDAR, is "differential light absorption and ranging" ("DIAL"),[262] which, compared with emission factor estimates, has been found to detect 33 times more VOC and *96 times more benzene* (a known carcinogen) from

[261] The EPA explains: "The FTIR technology … has the capability to measure more than 100 of the 189 Hazardous Air Pollutants (HAPs) listed in Title III of the Clean Air Act Amendments of 1990 (CAAA). Upon passage of the CAAA, measurement methods existed for only 40 of the HAPs. The FTIR has the capability of measuring multiple compounds simultaneously, thus providing an advantage over current measurement methods which measure only one or several HAPs; FTIR can provide a distinct cost advantage since it can be used to replace several traditional methods (cost savings can vary depending on the number of compounds present)." EPA Technology Transfer Network – Emission Measurement Center, available at http://www.epa.gov/ttn/emc/monitor.html#ftir. *See also*, EPA Cost Manual, *supra* note 141, at 4.10: "[FTIR] detects compounds based on the absorption of infrared light at critical wavelengths. … Current FTIR CEMs can accurately monitor up to six gaseous compounds (SO_2, NO_x, CO, HCl, CO_2, and O_2), various hazardous air pollutants, and volatile organic compounds simultaneously. … Although FTIR instruments tend to be more expensive than other analyzers, the ability to monitor multiple pollutants with one instrument improves its cost effectiveness."

[262] The acronym "DIAL" stands for "Differential Absorption LIDAR," and "LIDAR" stands for "Light Detection and Ranging."

storage emissions, and 12 times more VOC and 8 times more benzene from fugitive emissions.[263]

[263] Allan Chambers, P.Eng. and Mel Strosher, "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection," (Alberta Research Council, March 31, 2006 – revised November 1, 2006) at iv, *available at* http://www.arc.ab.ca/ARC-Admin/UploadedDocs/Dial%20Final%20Report%20Nov06.pdf.

APPENDIX C

“Significant” Emission Increase Thresholds for “Major Modifications” at Oil Refineries Pursuant to 40 C.F.R. § 51.166(b)(23)(i)

Carbon monoxide:	100 tons per year (“tpy”)
Nitrogen oxides:	40 tpy
Sulfur dioxide:	40 tpy
Particulate matter:	25 tpy of particulate matter emissions; 15 tpy of PM_{10} emissions
Ozone:	40 tpy of volatile organic compounds or NO_X
Lead:	0.6 tpy
Fluorides:	3 tpy
Sulfuric acid mist:	7 tpy
Hydrogen sulfide (H_2S):	10 tpy
Total reduced sulfur (including H_2S):	10 tpy
Reduced sulfur compounds (including H_2S):	10 tpy

<u>APPENDIX D</u>

<u>Ambiguous Language That May Indicate Practical Enforceability Problems</u>[264]

Problem Language	Discussion	Correction
"Normally," as in: "The permittee shall normally inspect the unit daily."	The term "normally" is subject to interpretation. Is the permittee still "normally" inspecting on a daily basis if inspections take place only 5 days out of 7? This language may place a burden on the permitting authority to show that the source's failure to inspect daily violated the requirement to "normally" inspect the unit daily.	Require that specific language be substituted for ambiguous language. Example: "The permittee shall inspect the unit daily." If necessary to allow for missed inspections, the permit could include a data recovery provision.
"As soon as possible; promptly," as in: "The permittee shall take corrective action as soon as possible."	"As soon as possible" and "promptly" are open-ended. Without an outer limit defined in the permit, the burden may be on the permitting authority to prove that the source could or should have acted sooner.	Require that an outer time limit be set on any actions required to occur "as soon as possible" or "promptly." Example: "The permittee shall take corrective action as soon as possible but no later than within 24 hours."
"Significant," as in: "The permittee shall take corrective action if parameters are significantly out of range."	"Significant" must be defined for the permit to be enforceable. Otherwise, the burden may be on the permitting authority to show that a problem is significant.	Specify parameter levels or ranges which will trigger action. For example: "The permittee shall take corrective action if parameters are more than 10% out of the range defined in condition xx." Or "The permittee shall take corrective action if pressure drop is less than 15 inches for more than one hour."

[264] Excerpted from EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-60.

"Should" or "may," as in: "The permittee should inspect daily. The permittee may test monthly."	"Should" indicates a preference, rather than a requirement, and is not appropriate for permit conditions unless the underlying applicable requirement contains provisions that are not mandatory but are recommendations only. "May" indicates an option, rather than a requirement, and is not appropriate for permit conditions.	Require that all required permit terms use "shall" or "must." For example: "The permittee must inspect daily," or "the permittee shall test monthly."
"As suggested by the manufacturer's specifications," as in: "The permittee shall maintain pressure drop as suggested by the manufacturer's specifications."	It is acceptable to use the manufacturer's recommendations as the basis for the numbers that go into the permit if there is no better data. However, the specific numbers must be incorporated into the permit rather than a reference to a document which may not include clear requirements.	Require that the specific numbers (which may be based on the manufacturer's recommendations) be included in the permit term. For example: "The permittee shall maintain pressure drop greater than 15 inches."
"Take reasonable precautions," as in: "The permittee shall take reasonable precautions to reduce fugitive emissions."	"Reasonable precautions" may be too subjective to be practically enforceable. The permit must identify the minimum activities that constitute "reasonable precautions."	Require the permit to include the specific measures that must be taken. For example: "The permittee shall conduct monthly audits of the facility to assure that the minimum reasonable precautions for preventing fugitive emissions are implemented and shall maintain records in accordance with condition xx. For the purposes of this condition, reasonable precautions shall include but are not limited to the following: Storing and mixing volatile materials in covered containers; storing all solvents or solvent containing cloth or other material used for surface

		preparation in closed containers; … [other specific conditions].”
“Use best engineering practices,” as in: “The permittee shall use best engineering practices to operate and maintain the boiler.”	This is the same issue as “reasonable precautions.” To be practically enforceable, “best engineering practices” must be defined/specified in the permit.	Require that the engineering practices be specified in the permit. For example: “The permittee shall use best engineering practices to operate and maintain the boiler which shall include but not be limited to servicing the boilers at least once each calendar year to assure proper combustion is occurring and that the units are in proper operating condition.”

APPENDIX E

Unacceptable Credible Evidence-Limiting Language[265]

Type of Language	Examples
Language that specifies that only certain types of data can be used to determine compliance	• "The monitoring methods specified in this permit are the sole methods by which compliance with the associated limit is determined." • "Monitoring and reporting requirements are requirements that the permittee uses to determine compliance...." "Compliance with this provision will be demonstrated by ....(insert periodic monitoring provisions)."
Language that specifies that certain types of data are more credible than others	• "Reference test method results supersede parametric monitoring data." • "The EPA Reference Test Method results supersede CEMS data."
Language that excuses violations under certain conditions	• "The permittee is considered to be in compliance if less than 5% of any CEMS monitored emission limit averaging periods exceeds the associated emission limit." • "If the permitting authority does not take action on an excess emissions demonstration by responding to the permittee in writing within 90 days of receipt, the permitting authority will be deemed to have made a determination that the excess emissions were unavoidable." • "Excess emissions that are unavoidable are not violations of permit terms." • "A 'deviation from permit requirements' shall not include any incidents whose

[265] Excerpted from EPA Title V Guidelines – Practical Enforceability, *supra* note 159, at III-630 to III-64.

	duration is less than 24 hours from the time of discovery by the permittee."

APPENDIX F

Minimum Criteria for Excess Emission Affirmative Defenses (Where Available)[266]

Elements of Affirmative Defense for Malfunction Excess Emissions	Elements of Affirmative Defense for Startup and Shutdown Excess Emissions
1. **The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator**; 2. **The excess emissions: (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices**; 3. To the maximum extent practicable, the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions; 4. **Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded**…; 5. The amount and duration of the excess emissions … were minimized to the maximum extent practicable during periods of such emissions; 6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;	1. **The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design**; 2. The excess emissions were **not part of a recurring pattern** indicative of inadequate design, operation, or maintenance; 3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; 4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions; 5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable; 6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality; 7. All emission monitoring systems were kept in operation if at all possible;

[266] Excerpted from EPA SSM Policy, *supra* note 177, at 3-4, 6 (emphases added).

7. All emission monitoring systems were kept in operation if at all possible; 8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; 9. **The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance**; and 10. The owner or operator properly and promptly notified the appropriate regulatory authority.	8. The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and 9. The owner or operator properly and promptly notified the appropriate regulatory authority.

APPENDIX G

Key Steps in the "Top-Down" BACT Determination[267]

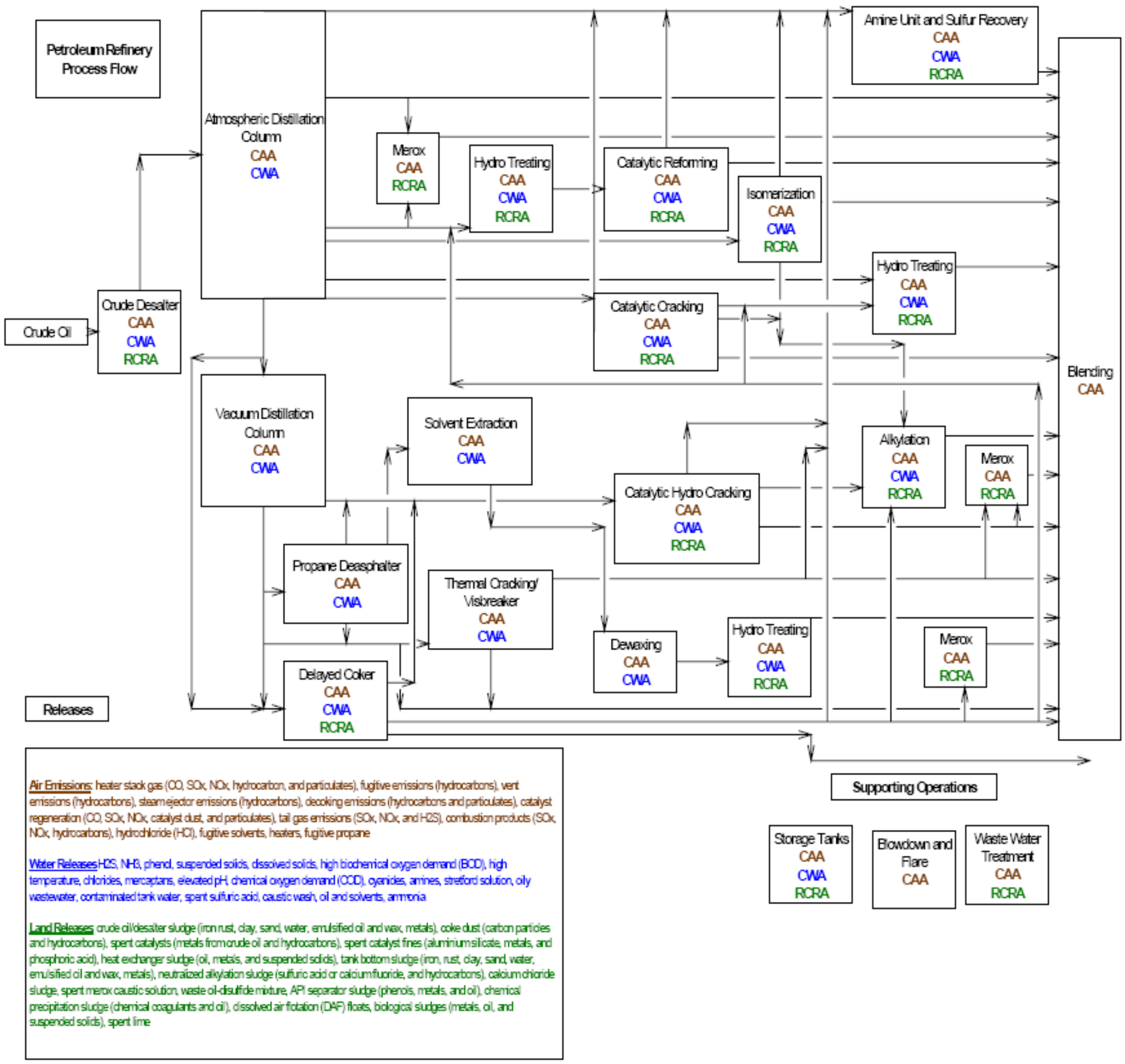
STEP 1:	IDENTIFY ALL CONTROL TECHNOLOGIES. ● List is comprehensive (LAER included).
STEP 2:	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS. ● A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.
STEP 3:	RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS. Should include: ● control effectiveness (percent pollutant removed); ● expected emission rate (tons per year); ● expected emission reduction (tons per year); ● energy impacts (BTU, kWh); ● environmental impacts (other media and the emissions of toxic and hazardous air emissions); and ● economic impacts (total cost effectiveness, incremental cost effectiveness).
STEP 4:	EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS. ● Case-by-case consideration of energy, environmental, and economic impacts. ● If top option is not selected as BACT, evaluate next most effective control option.
STEP 5:	SELECT BACT ● Most effective option not rejected is BACT.

[267] Excerpted from EPA NSR Workshop Manual, *supra* note 35, at B.6.

APPENDIX H

Petroleum Refining Process Flow Chart[268]

This flow chart illustrates the petroleum refinery process, potential releases, potential release points, and the major applicable environmental regulations.



268 Excerpted from EPA OIG Report, *supra* note 8, Appendix C.

APPENDIX I

Mandatory Class I Areas[269]

D R A F T
OCTOBER 1990

II. CLASS I AREAS AND THEIR PROTECTION

Under the CAA, three kinds of Class I areas either have been, or may be, designated. These are:

- ***mandatory Federal Class I areas***;
- ***Federal Class I areas***; and
- ***non-Federal Class I areas***.

Mandatory Federal Class I areas are those specified as Class I by the CAA on August 7, 1977, and include the following areas in existence on that date:

- international parks;
- national wilderness areas (including certain national wildlife refuges, national monuments and national seashores) which exceed 5,000 acres in size;
- national memorial parks which exceed 5,000 acres in size; and
- national parks which exceed 6,000 acres in size.

Mandatory Federal Class I areas, which may not be reclassified, are listed by State in Table E-1. They are managed either by the Forest Service (FS), National Park Service (NPS), or Fish and Wildlife Service (FWS).

The States and Indian governing bodies have the authority to designate additional Class I areas. These Class I areas are not "mandatory" and may be reclassified if the State or Indian governing body chooses. States may reclassify either State or Federal lands as Class I, while Indian governing bodies may reclassify only lands within the exterior boundaries of their respective reservations.

[269] Excerpted from EPA NSR Workshop Manual, *supra* note 35, at E.2 – E.6.

TABLE E-1. MANDATORY CLASS I AREAS

State/Type/Area	Managing Agency	State/Type/Area	Managing Agency
Alabama		***California - Continued***	
National Wilderness Areas		*National Wilderness Areas*	
Sipsey	FS	Agua Tibia	FS
		Caribou	FS
Alaska		Cucamonga	FS
National Parks		Desolation	FS
Denali	NPS	Dome Land	FS
		Emigrant	FS
National Wilderness Areas		Hoover	FS
Bering Sea	FWS	John Muir	FS
Simeonof	FWS	Joshua Tree	NPS
Tuxedni	FWS	Kaiser	FS
		Lava Beds	NPS
Arizona		Marble Mountain	FS
National Parks		Minarets	FS
Grand Canyon	NPS	Mokelumne	FS
Petrified Forest	NPS	Pinnacles	NPS
		Point Reyes	NPS
National Wilderness Areas		San Gabriel	FS
Chiricahua Nat. Monu.	NPS	San Gorgonio	FS
Chiricahua	FS	San Jacinto	FS
Galiuro	FS	San Rafael	FS
Mazatzal	FS	South Warner	FS
Mt. Baldy	FS	Thousand Lakes	FS
Pine Mountain	FS	Ventana	FS
Saguaro Nat. Monu.	NPS	Yolla Bolly-Middle-Eel	FS
Sierra Ancha	FS		
Superstition	FS	***Colorado***	
Sycamore Canyon	FS	*National Parks*	
		Mesa Verde	NPS
Arkansas		Rocky Mountain	NPS
National Wilderness Areas			
Caney Creek	FS	*National Wilderness Areas*	
Upper Buffalo	FS	Black Canyon of the Gunn.	NPS
		Eagles Nest	FS
California		Flat Tops	FS
National Parks		Great Sand Dunes	NPS
Kings Canyon	NPS	La Garita	FS
Lassen Volcanic	NPS	Maroon Bells Snowmass	FS
Redwood	NPS	Mount Zirkel	FS
Sequoia	NPS	Rawah	FS
Yosemite	NPS	Weminuche	FS
		West Elk	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
Florida	
National Parks	
Everglades	NPS
National Wilderness Areas	
Bradwell Bay	FS
Chassahowitzka	FWS
Saint Marks	FWS
Georgia	
National Wilderness Areas	
Cohutta	FS
Okefenokee	FWS
Wolf Island	FWS
Hawaii	
National Parks	
Haleakala	NPS
Hawaii Volcanoes	NPS
Idaho	
National Parks	
Yellowstone (See Wyoming)	
National Wilderness Areas	
Craters of the Moon	NPS
Hells Canyon (see Oregon)	
Sawtooth	FS
Selway-Bitterroot	FS
Kentucky	
National Parks	
Mammoth Cave	NPS
Louisiana	
National Wilderness Areas	
Breton	FWS
Maine	
National Parks	
Acadia	NPS
National Wilderness Areas	
Moosehorn	FWS
Michigan	
National Parks	
Isle Royale	NPS
National Wilderness Areas	
Seney	FWS
Minnesota	
National Parks	
Voyageurs	NPS
National Wilderness Areas	
Boundary Waters Canoe Ar.	FS
Missouri	
National Wilderness Areas	
Hercules-Glades	FS
Mingo	FWS
Montana	
National Parks	
Glacier	NPS
Yellowstone (See Wyoming)	
National Wilderness Areas	
Anaconda-Pintlar	FS
Bob Marshall	FS
Cabinet Mountains	FS
Gates of the Mountain	FS
Medicine Lake	FWS
Mission Mountain	FS
Red Rock Lakes	FWS
Scapegoat	FS
Selway-Bitterroot (see Idaho)	
U.L. Bend	FWS
Nevada	
National Wilderness Areas	
Jarbridge	FS
New Hampshire	
National Wilderness Areas	
Great Gulf	FS
Presidential Range-Dry R.	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
New Jersey	
National Wilderness Areas	
Brigantine	FWS
New Mexico	
National Parks	
Carlsbad Caverns	NPS
National Wilderness Areas	
Bandelier	NPS
Bosque del Apache	FWS
Gila	FS
Pecos	FS
Salt Creek	FWS
San Pedro Parks	FS
Wheeler Peak	FS
White Mountain	FS
North Carolina	
National Parks	
Great Smoky Mountains (see Tennessee)	
National Wilderness Areas	
Joyce Kilmer-Slickrock	FS
Linville Gorge	FS
Shining Rock	FS
Swanquarter	FWS
North Dakota	
National Parks	
Theodore Roosevelt	NPS
National Wilderness Areas	
Lostwood	FWS
Oklahoma	
National Wilderness Areas	
Wichita Mountains	FWS
Oregon	
National Parks	
Crater Lake	NPS
Oregon - Continued	
National Wilderness Areas	
Diamond Peak	FS
Eagle Cap	FS
Gearhart Mountain	FS
Hells Canyon	FS
Kalmiopsis	FS
Mountain Lakes	FS
Mount Hood	FS
Mount Jefferson	FS
Mount Washington	FS
Strawberry Mountain	FS
Three Sisters	FS
South Carolina	
National Wilderness Areas	
Cape Romain	FWS
South Dakota	
National Parks	
Wind Cave	NPS
National Wilderness Areas	
Badlands	NPS
Tennessee	
National Parks	
Great Smoky Mountains	NPS
National Wilderness Areas	
Joyce Kilmer-Slickrock (see North Carolina)	
Texas	
National Parks	
Big Bend	NPS
Guadalupe Mountain	NPS

TABLE E-1.* Continued

State/Type/Area	Managing Agency
Utah	
National Parks	
Arches	NPS
Bryce Canyon	NPS
Canyonlands	NPS
Capitol Reef	NPS
Vermont	
National Wilderness Areas	
Lye Brook	FS
Virgin Islands	
National Parks	
Virgin Islands	NPS
Virginia	
National Parks	
Shenandoah	NPS
National Wilderness Areas	
James River Face	FS
Washington	
National Parks	
Mount Rainier	NPS
North Cascades	NPS
Olypmic	NPS
National Wilderness Areas	
Alpine Lakes	FS
Glacier Peak	FS
Goat Rocks	FS
Mount Adams	FS
Pasayten	FS
West Virginia	
National Wilderness Areas	
Dolly Sods	FS
Otter Creek	FS
Wisconsin	
National Wilderness Area	
Rainbow Lake	FWS
Wyoming	
National Parks	
Grand Teton	NPS
Yellowstone	NPS
National Wilderness Areas	
Bridger	FS
Fitzpatrick	FS
North Absaroka	FS
Teton	FS
Washakie	FS
International Parks	
Roosevelt-Campobello	n/a