December 4, 2014

Submitted via email to SEPA@KalamaMfgFacilitySEPA.com

Submitted via electronic filing at www.ferc.gov

Port of Kalama
Attention: Ann Farr, SEPA Responsible Official
110 W. Marine Drive
Kalama, WA 98625

Cowlitz County
Elaine Placido, Director of Building and Planning
207 4th Ave. North
Kelso, WA 98626

Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Re: Comments on the Scope of the Environmental Impact Statement for the Kalama Manufacturing & Marine Export Facility, FERC Docket No. CP15-8-000

Dear Ms. Farr, Ms. Placido, and the Secretary of the Federal Energy Regulatory Commission:

The Northwest Environmental Defense Center and Columbia Riverkeeper (collectively, Commenters) submit these comments regarding the scope of the Environmental Impact Statement (EIS) assessing the impacts of NW Innovation Works' proposal to construct and operate a natural gas-to-methanol production plant and storage facilities (methanol export facility) at the Port of Kalama (Port). Commenters are each non-profit public interest organizations, and together representing thousands of members dedicated to protecting the public health, environment, and natural resources.

Commenters urge the Port to prepare an EIS that fully and accurately discloses the wide reaching impacts of the proposed methanol export facility. NW Innovation Works' proposal to build a methanol production plant, pipeline, and marine terminal poses a threat to many natural resources in the Pacific Northwest in terms of adverse impacts on air quality, water quality, fish and wildlife, and public health. Construction and operation of the methanol export facility, including the attendant vehicle and marine vessel traffic, directly threatens the interests of many of Commenters' members. The Port must prepare an EIS that addresses the significant direct, indirect, and cumulative impacts of NW Innovation Works' proposed methanol export facility.

I. NW Innovation Works' methanol export facility is a major infrastructure proposal that will change the landscape of the region.

NW Innovation Works proposes to construct and operate a natural gas-to-methanol production plant and storage facilities in an industrial park owned by the Port of Kalama. This project consists of three main parts: (1) the production plant, (2) a new 3.1-mile-long lateral distribution pipeline to deliver natural gas through Cowlitz County to the plant, and (3) a new deep draft marine terminal facility to load methanol onto ships.

But the specifics of the proposed facility demonstrate it will be much more than that: the methanol export facility will include two methanol production lines, an administrative and lab building, employee parking, access roadways, a fire station, two air separation units, air storage, water production wells, water storage and treatment facilities, wastewater treatment facilities, cooling towers, a flare system for the disposal of flammable gases and vapors, substations, and generators. The lateral pipeline will also require metering facilities and miscellaneous appurtenances. 79 Fed. Reg. 66366 (Nov. 7, 2014) (Federal Energy Regulatory Commission Notice of Application; Northwest Pipeline Company, LLC).

The Federal Energy Regulatory Commission's (FERC) public notice of the pipeline application states that the pipeline will be designed to provide 320,000 dekatherms per day of natural gas to the methanol export facility. *Id.* The methanol export facility would consist of two phases, each capable of producing 5,000 metric tons per day of methanol. Following production, methanol will be stored in non-pressurized storage tanks with a capacity of 200,000 metric tons.

This infrastructure is proposed for Cowlitz County, with much of the construction proposed for the Port of Kalama located along the Columbia River. The Columbia is the largest river flowing into the eastern Pacific, and the second largest North American river by volume. Jim Shaw, *The Columbia Snake River System*, Pacific Maritime, 1 (2006). It is "arguably the most significant environmental force in the Pacific Northwest region of the United States." Center for Columbia River History, available at http://www.ccrh.org/river/history.htm (last accessed Dec. 4, 2014). Historically used as a major highway for exporting commodities to Pacific Rim Nations, numerous fossil fuel export projects have recently been proposed on the Columbia River that will drastically increase the vessel traffic. In particular, this methanol export facility would exacerbate the threats these projects pose to the river, further threatening the delicate ecosystem of the Columbia River Estuary. Given the substantial amount of proposed infrastructure construction, the methanol export facility will dramatically change the landscape of the region.

II. Pursuant to federal and state law, the Port and FERC must consider direct, indirect, and cumulative impacts of the proposed methanol export facility.

a. The National Environmental Policy Act

Section 102(2)(C) of the National Environmental Policy Act establishes an "action- forcing" mechanism to ensure "that environmental concerns will be integrated into the very process of agency decisionmaking." *Andrus v. Sierra Club*, 442 U.S. 347, 350 (1979). Pursuant to that statutory provision, "all agencies of the Federal Government shall ... include in every recommendation or report on ... major Federal actions significantly affecting the quality of the human environment, a detailed statement" known as an environmental impact statement (EIS) that addresses "the environmental impact of the proposed action, any adverse environmental impacts which cannot be avoided . . . , alternatives to the proposed action," and other environmental issues. 42 U.S.C. § 4332.

NEPA has two fundamental purposes: (1) to guarantee that agencies take a "hard look" at the consequences of their actions before the actions occur by ensuring that "the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impact," *Robertson v. Methow Valley Citizens Council,* 490 U.S. 332, 349 (1989), and (2) to ensure that "the relevant information will be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision," *id.* at 349. NEPA "emphasize[s] the importance of coherent and comprehensive up-front environmental analysis to ensure informed decision making to the end that 'the agency will not act on incomplete information, only to regret its decision after it is too late to correct.'" *Blue Mountains Biodiversity Project v. Blackwood*, 161 F.3d 1208, 1216 (9th Cir. 1998).

Under NEPA, the analysis in an EIS must consider direct, indirect, and cumulative effects. "Effects includes ecological (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, economic, social, or health, whether direct, indirect, or cumulative." 40 C.F.R. § 1508.8. The direct effects of an action are those "caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a). The indirect effects of an action are those "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." 40 C.F.R. § 1508.8(b). For example, "[i]ndirect effects may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." *Id.* Cumulative effects are the impacts on the environment that result from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. 40 C.F.R. § 1508.7.

b. Washington's State Environmental Policy Act

In adopting the State Environmental Policy Act (SEPA), the Washington legislature declared the protection of the environment to be one of the state's core priorities. RCW 43.21C.010. SEPA states that "[t]he legislature recognizes that each person has a fundamental and inalienable right to a healthful environment and that each person has a responsibility to contribute to the preservation and enhancement of the environment." RCW 43.21C.020(3). This policy statement, which is more strongly worded than a similar provision in NEPA, "indicates in the strongest possible terms the basic importance of environmental concerns to the people of the state." *Leschi v. Highway Comm'n*, 84 Wn.2d 271, 279-80 (1974).

At the heart of SEPA is the requirement to fully analyze the environmental impacts of major projects. RCW 43.21C.031(1). Like NEPA, SEPA requires an EIS for any action that has a significant effect on the quality of the environment. WAC 197-11-330. SEPA defines "significant" as a "reasonable likelihood of more than a moderate adverse impact on environmental quality." WAC 197-11-794. SEPA and its implementing regulations explicitly require consideration of direct and indirect climate impacts. See RCW 43.21C.030(f) (directing agencies to "recognize the world- wide and long-range character of environmental problem); WAC 197-11-444 (listing "climate" among elements of the environment that must be considered in SEPA review). SEPA also requires agencies to consider the cumulative impacts of a proposed action. WAC 197-11-060(4).

Ultimately, the purpose of the Port's and FERC's analysis is not to generate paperwork. Rather, the EIS allows decision-makers to make judgments based on a fully informed appreciation for the environmental impact of those decisions, the available alternatives, and any mitigation measures that may be appropriate.

III. The Port and FERC must consider a reasonable range of alternatives in the EIS.

The alternatives analysis is "the heart of the environmental impact statement." 40 C.F.R. § 1502.14. CEQ's regulations implementing NEPA, 40 C.F.R. § 1502.14, explain that a reasonable range of alternatives should be presented and compared in the EIS to allow for a "clear basis for choice among options by the decisionmaker and the public." Crucially, the alternatives must include "reasonable alternatives not within the jurisdiction of the lead agency," and must include" appropriate mitigation measures not already included in the proposed action or alternatives." *Id.* Because alternatives are central to decisionmaking and mitigation, "the existence of a viable but unexamined alternative renders an environmental impact statement inadequate." *Oregon Natural Desert Ass'n v. Bureau of Land Management*, 625 F.3d 1092, 1122 (9th Cir. 2008) (internal citations omitted).[1]

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[1] The Washington Supreme Court has ruled that the state should look to NEPA for guidance. "Since much of the language from SEPA is taken verbatim from NEPA (signed into law January 1, 1970), we look when necessary to the federal cases construing and applying provisions of

Here, the Port and FERC must at a minimum consider a "no-action" alternative, alternative locations for the proposed infrastructure, and smaller proposals at various locations. The "no-action" alternative must carefully and accurately define the baseline conditions of the region to properly compare resulting impacts with and without the proposed methanol export facility. Consideration of alternative site locations is essential to understanding if a viable alternative location exists that will have less adverse environmental impacts overall. Specifically, the Port must consider alternative locations of lower biological production, away from sensitive habitats and migration routes of marine mammals or protected migratory species. *See, e.g.*, National Marine Fisheries Service (NMFS) Comments on Notice of Intent for the Oregon LNG Export Project, Oregon (Docket No. PF12-18-000) and Washington Expansion Project, Washington (PF12-20-000) (attached as Exhibit A). The Port and FERC must also consider the proposed methanol terminal in Oregon as an alternative to the proposed terminal Washington State.

Finally, the Port and FERC should consider proposals for smaller scale projects at various locations. This alternative would meet the stated purpose and need, but may also disperse the various impacts described in the next section such that there is an overall lesser impact to the region. Under the current proposal, the Port and Cowlitz County will feel all of the impacts. Dispersing those impacts throughout the state would lessen the direct adverse impacts. It would also likely increase the number of jobs and thereby provide a greater net benefit to the state of Washington.

IV. NW Innovation Works' proposed methanol export facility will have wide-ranging impacts that the EIS must fully address.

SEPA requires consideration of the "environmental impacts" of a proposed action, regardless of whether they are impacts to the natural or built environment, WAC 197-11-444, adverse or beneficial. WAC 197-11-752 (defining "impacts" as "the effects or consequences of actions" but omitting any distinction between beneficial or adverse impacts). Environmental impacts to consider in an EIS include impacts to the earth, such as geology and the soils; air, including air quality, odor, and climate; water, including water quality, floods, and public water supply; and energy and natural resources, such as the amount required or rate of use. *Id.* Elements of the built environment that must be addressed in an EIS include environmental health, such as noise or releases to the environment affecting public health; land and shoreline use, including aesthetics; and transportation. *Id.* The EIS must address the likely direct, indirect, or cumulative impacts that fall within these categories.

Air quality and visual impacts

NW Innovation Works' proposed methanol export facility would degrade local air quality in the immediate vicinity and in the surrounding communities. Likely emissions

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NEPA for guidance." *Eastlake Cmty. Council v. Roanoke Assocs., Inc.*, 82 Wn.2d 475, 488 n.5 (Wash. 1973).

from normal methanol production operations include nonmethane hydrocarbons, carbon monoxide, nitrogen oxides, sulfur oxides, and particulate matter. Delucchi, *Emissions of Criteria Pollutants, Toxic Air Pollutants, and Greenhouse Gases from the Use of Alternative Transportation Modes and Fuels*, Institute of Transportation Studies, University of California, Davis, Table 27, page 119 (attached as Exhibit B).

NW Innovation Works acknowledges the proposed methanol production facility must obtain several permits, including a Prevention of Significant Deterioration (PSD) permit under the Clean Air Act. The impacts of any emissions authorized under any PSD permit must be considered. This should include consideration of the greenhouse gases likely to result when converting natural gas to methanol. Methane is the primary component of natural gas. It escapes into the air as fugitive methane emissions along every stage of the natural gas production process. Methane currently accounts for about 9 percent of domestic greenhouse gas emissions. *See* Executive Office of the President, *The President's Climate Action Plan* (June 2013), page 10 (attached as Exhibit C). The EIS also must include emissions from marine vessels when engaged in active loading and unloading operations in support of the methanol export facility's purpose of exporting methanol to China. In addition, the Port must fully analyze how the facility will degrade the visual quality of the region.

The EIS must consider the true costs, in terms of levelized costs, of the plant, including likely future carbon taxes. This should include costs to the region and to the state of Washington, generally. The air quality assessment should also consider how this facility will impact Washington's ability to achieve its renewable portfolio standard of 15% renewables by 2020 and all cost-effective conservation. Finally, the EIS must assess the public health impacts of increasing air pollution in the area.

Climate change

The Port must consider climate change impacts of the proposed methanol export facility. *See, e.g.*, *Rech v. San Juan Cnty.*, 2008 WL 5510438 (Wash. Shorelines Hearings Board June 12, 2008) at *12 n.8 ("We further note an emerging trend in the case law under the National Environmental Policy Act ("NEPA") and state NEPA analogues in which courts are increasingly requiring agencies to analyze climate change impacts during environmental assessments.").[2] This analysis should consider the impacts resulting from the use of methanol produced at this plant within the United States and abroad. Methane emissions (as noted above, every stage of the natural gas production process emits fugitive methane) has a global warming potential more than 20 times greater than carbon dioxide. *See* Exhibit C at 10. As President Obama stated in his Climate Action Plan, "[c]urbing emissions from methane is critical to our overall effort to address global climate change." *Id.* Thus the EIS must consider the impacts of this proposal on the state of Washington's, and the nation's attempts to combat global climate change.

[2] *See supra,* note 1.

Water resources

The proposed methanol export facility is likely to impact water quality in numerous ways, including water withdrawals during construction, stormwater runoff from terminal facilities during both construction and operation, discharge of pollutants into the Columbia River as a result of dredging and day-to-day operations, and water withdrawals from the Columbia River for the production process. Impacts of polluted stormwater runoff from the terminal construction site should include the impacts to water quality from removing riparian habitat and surface runoff to the Columbia River. Marine vessels may introduce invasive species through, for example, ballast water discharges. Such introductions will create added costs to the state to control ecological resources. The EIS must describe the full range of direct, indirect, and cumulative impacts to water quality.

NW Innovation Works proposes to conduct dredging to accommodate deep draft vessels at the proposed marine terminal. Dredge and fill activities associated with construction, for example, would increase turbidity and mobilize toxics in river sediment. The EIS must disclose the direct and indirect impacts of dredge spoil disposal, as well as the cumulative impacts of past, present, and reasonably foreseeable future dredge spoil disposal actions. These activities also likely require a federal dredge and fill permit under section 404 of the Clean Water Act. Impacts of this permit must be considered in the Port's and FERC's environmental analyses.

The Port and FERC should analyze the direct and indirect impacts of the pipeline construction on water quality, including the potential for the fracturing of a streambed or riverbed which could release drilling lubricants into the water body. Construction in riparian areas and along steep slopes increases the risk of erosion and sedimentation in important water bodies. Because the pipeline and dredging are both essential aspects of NW Innovation Works' proposal, both the federal and state environmental laws require the Port and FERC to consider the impacts from these activities in a single EIS.

The proposal states that the non-pressurized storage tanks, capable of storing 200,000 metric tons of methanol, will be surrounded by a containment area. The details of that containment, including capacity, have not been disclosed. This aspect must be carefully reviewed in the EIS. Secondary containment is only as functional as its capacity. Thus NW Innovation Works must demonstrate that the containment for the storage tanks exceeds the capacity of the tanks (greater than 200,000 metric tons).

Finally, it is unclear from NW Innovation Works' materials how much water the methanol export facility will consume as part of its daily operations. Given that the process of converting natural gas to methanol requires some cooling, it is likely that the facility will require large amounts of water from the Columbia River. This use will be a major direct impact to the water quality of the river and will likely adversely impact aquatic life within the river.

Impacts to fish and wildlife

The Port's EIS must disclose the wide-ranging impacts to endangered and threatened species and other fish and wildlife threatened by construction and operation of a methanol production facility, lateral pipeline, and marine terminal. The Columbia River is home to significant recovery efforts for listed salmonids. The Port must examine the direct and indirect impacts of the project on ESA-listed salmonids, including the cumulative effects of other actions and programs of the federal government, and fully disclose the combined impact of ongoing and reasonably foreseeable future actions. This includes the impact of this project when considered in combination with the effects of other Corps dredging projects in the Columbia River, impacts from operation of the Bonneville dam, water withdrawals from the Columbia River authorized by the U.S. Bureau of Reclamation, and impacts from logging and grazing approved and permitted by the U.S. Forest Service and Bureau of Land Management. This also includes analyzing increased rates of fish stranding and bank erosion. The EIS must assess the increased risk to fish and wildlife from vessel spills and accidents. The Port must assess the cumulative impacts of actions authorized and carried out by state, local, and private entities.

Public Safety

NW Innovation Works' project raises significant public health and safety issues. The Port's EIS should fully address and disclose the potential risks to public safety posed by the proposed facility. Methanol is a highly flammable liquid and has been known to cause explosions resulting in serious injury or death. *See, e.g.*, Investigation Report, *Methanol Tank Explosion and Fire*, U.S. Chemical Safety & Hazard Investigation Board (2006) (available at http://www.csb.gov/assets/1/19/Bethune_Final_Report.pdf) (attached as Exhibit D) (investigating an explosion inside a methanol storage tank at a wastewater treatment facility in Florida that left 2 people dead, 1 critically injured). The proposed storage facilities must be assessed for susceptibility to natural disasters such as earthquakes or tsunamis, as well as human-caused disasters such as terrorist attacks. The proposed natural gas pipelines pose a similar explosion risk following a rupture. The EIS must examine direct, indirect, and cumulative impacts of building and operating the facility and pipelines, including loss of life, property destruction and damage, and wildfires from an explosion.

NW Innovation Works' proposed methanol export facility will put a significant number of people at risk of catastrophic accident resulting from a natural gas or methanol incident. The proposed pipelines will cross near residences and through communities as it slices through Cowlitz County. The marine vessel route will crisscross routes used by fisherman and recreationists. The EIS must fully disclose the consequences of an accidental or terrorist-induced ignition at or near the facility. The analysis should address:

- Terminal safety threats, including an assessment of the risks of varying levels of accidents at the terminal

- Marine vessel safety threats, including shipping routes and the risks of varying levels of accidents on the Columbia River and while docked at the terminal

- Pipeline explosion or release

- Maps illustrating threats to loss of human life and property

- Emergency response plans, including identification of resources, the order of response and contacts in case of an emergency, identification of funding, and outline of training for employees

Induced growth

The facilities contemplated under this proposal are likely to induce growth at the Port, as well as in the surrounding region. The EIS must consider any resulting induced growth as an indirect impact of the proposed methanol export facility. 40 C.F.R. § 1508.8(b) (noting that "[i]ndirect effects may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems").

In addition, the proposed facility infrastructure may itself induce industrial growth, since it may be used for different purposes in the future. This is a very definite possibility that the Port must consider. For example, the crude oil transloading facility located in Clatskanie, Oregon, is the site of a former ethanol manufacturing facility that went out of business. Without the existing infrastructure, Global Partners could not have as easily initiated operations at that site. Yet the existing infrastructure made it possible for Global Partners to switch from ethanol production and export to crude oil transloading based on minimal permit modifications. Here, too, construction of major infrastructure at the Port is likely to pave the way for future industrial use of that same infrastructure. The Port must consider these likely impacts in the EIS.

U.S. natural gas production grew by 23 percent between 2007 and 2012, and increased an additional 10 percent in 2013. Energy Information Administration, *U.S. natural gas reserves increase 10% in 2013 to reach a record 354 Tcf*, available at http://www.eia.gov/todayinenergy/detail.cfm?id=19051 (last accessed Dec. 4, 2014). The methanol export facility will provide a key connection between U.S. supply of natural gas and China's demand for methanol. The methanol export facility is likely to induce additional fracking operations by increasing demand. The EIS must consider the induced additional fracking, and the impacts of fracking on the natural environment, as an indirect effect of this proposal to increase international exports of methanol.

Increased environmental risks

Producing fuel, including the production of methanol from natural gas, comes with considerable environmental risks. These risks come at all levels, whether extracting the natural gas, transporting the gas, producing methanol, storing methanol, or transporting the methanol. *See, e.g.*, U.S. Environmental Protection Agency, *Clean Energy: Natural Gas*, available at http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (last accessed Dec. 4, 2014) (noting that "[t]he extraction of natural gas . . . can destroy natural habitat for animals and plants" and that "[p]ossible impacts include erosion, loss of soil productivity, and landslides."). The U.S. Government Accountability Office reported that "[o]il and gas development, whether conventional or shale oil and gas, pose inherent environmental and public health risks, but the extent of these risks associated with shale oil and gas development is unknown, in part, because the studies GAO reviewed do not generally take into account the potential long-term, cumulative effects." U.S. Government Accountability Office, *Oil and Gas: Information on Shale Resources, Development and Environmental and Public Health Risks* (Oct. 9, 2012) (attached as Exhibit E).

Use of methanol for plastics

Northwest Innovation Works plans to ship the produced methanol to China. There, it will be used to make olefin. Olefin is a key ingredient in manufacturing plastics for products. Unfortunately, Oregon and Washington see many of those plastic products washing up on Pacific Northwest coast lines. The EIS must consider these indirect impacts of the proposal.

Marine vessel traffic

The EIS must consider the direct, indirect, and cumulative impacts of increased marine vessel traffic in the Columbia River. These impacts must include an assessment of the direct impacts of vessel traffic on air quality, water quality, and wildlife, as well as the increased risk of collision and accident. Such impacts should include:

- Shoreline erosion resulting from large wakes, and increased turbidity
- Invasive species introduced in ballast water carried by the ships
- Vessel strikes of large marine mammals
- Standing of juvenile salmon on beaches due to large wakes created by deep draft vessels
- Increased risk of spills or accidents with other vessels

The EIS must also consider the cumulative impacts of the marine vessel traffic proposed for this facility, when combined with other existing or reasonably foreseeable future projects that will increase marine vessel traffic along the Columbia River. The number of deep draft vessels in the Columbia River reached its lowest numbers in 2009 with 1,397 vessels.[3] In 2010 it increased to 1,583 vessels[4] and since has remained steady

[3] VEAT (2009) (1286 C&P vessels + 111 tanker vessels = 1397 vessels total).

around 1,450 ships a year.[5] In 2013 there were 1,457 vessels on the Columbia River.[6] Numerous fossil fuel projects proposed along the Columbia River would add a large number of new vessels:

- **Ambre Millennium Bulk coal export terminal.** Longview, WA. At two loaded vessels per day, Ambre's Millennium project would add **730** outgoing vessels per year. [7]

- **Oregon LNG pipeline & terminal.** Warrenton, OR. According to information filed to the Federal Energy Regulatory Commission, the terminal would require **125** new outgoing LNG supertankers crossing the Columbia River Bar every year.[8]

- **Tesoro/Savage oil terminal.** Vancouver, WA. Tesoro/Savage's application to Washington EFSEC states that the project could require as many as **365** vessels per year to transport 360,000 barrels of crude oil each day. [9]

- **Global Partners oil terminal.** Port Westward, OR.[10] Global intends to sharply increase its shipments of crude oil through Port Westward. According to Oregon DEQ, Global could ship as much as 120,000 barrels/day, increasing vessel traffic by **115** vessels per year.

- **Northwest Innovation Works' (other) methanol export terminals.** Port of Tacoma, WA and Port Westward, OR. Two additional methanol export proposals would use large volumes of natural gas to produce and export methanol to China from the Port of Tacoma and Port Westward. Each facility would send out 2 ships per week,[11] totaling **208** ships per year.

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[4] VEAT (2010) (1467 C&P vessels + 116 tanker vessels = 1583 vessels total).
[5] VEAT (2013).
[6] VEAT (2013) (1293 C&P vessels + 164 tanker vessels = 1457 vessels total).
[7] Millennium Bulk Terminals, Joint Aquatic Resources Permit Application, 10 (2010) [hereinafter Millennium Bulk Terminals JARPA] ("At maximum throughput, approximately two vessels per day would be loaded.")
[8] Oregon LNG, Biological Assessment, 2-2 (2013).
[9] Tesoro/Savage, Biological Resources Report, Appendix H.1 to application to the Energy Facility Site Evaluation Council (EFSEC), 75 (2013) ("It is estimated that the proposed Facility will result in approximately 140 ship transits per year in 2016 (first full year of operations) up to 365 ship transits per year at full buildout.").
[10] Oregon Department of Environmental Quality Public Notice. February 28, 2014. (Global "significantly increased crude oil storage and loading and now intends to receive and transload as much as 1,839,600,000 gallons per year." One barrel of oil is 42 gallons. According to DEQ's notice, and converting gallons per year to barrels per day, Global intends to ship 120,000 barrels/day – an increase of 115,000 barrels over currently permitted levels. Assuming the same ratio of ships to barrels as the Vancouver Tesoro/Savage project (both hope to use Panamax vessels), the Global oil terminal will require roughly 115 additional ships outgoing per year.).
[11] http://www.thechronicleonline.com/news/article_b96d4192-82f7-11e3-a2be-001a4bcf887a.html.

These new projects would add **over 1,500 new outgoing deep draft vessels.**[12] The Columbia has not seen this many ships in over 20 years.

States have little control over the safety regulations that govern deep draft vessels. Following the devastation caused by the Exxon Valdez spill in Alaska, many states tried to create stronger regulations to protect their waters from oil spills. *U.S. v. Locke*, 529 U.S. 89, 94 (2002). Most significantly, Washington created the Office of Marine Safety, which promulgated regulations for tanker design, equipment, reporting, and operating requirements. *Id.* The Supreme Court struck down these regulations, deciding vessel requirements were in the purview of federal law. The Court concluded that only the federal government could regulate vessels, because they are used in interstate commerce and therefore, must be governed by a uniform set of federal regulations. *Id.* at 108-09. The Port must consider the state of Washington's inability to further regulate marine vessels when attempting to mitigate the likely direct, indirect and cumulative impacts that will result from increased marine vessel traffic under this proposal.

Combined impacts of NW Innovation Works' numerous proposals

The proposed methanol export facility is likely to result in potential environmental impacts of considerable importance, which is magnified when considered in the cumulative along with impacts from other similar projects in the region. Connected actions are those that are closely related and should be discussed in the same EIS. 40 C.F.R. § 1508.25(a)(1). Cumulative *actions*, as opposed to cumulative impacts, are those "which when viewed with other proposed actions have cumulatively significant impacts and should therefore be discussed in the same impact statement." 40 C.F.R. § 1508.25(a)(2). Similar actions are those "which when viewed with other reasonably foreseeable or proposed agency actions, have similarities that provide a basis for evaluating the environmental consequences together, such as common timing or geography." 40 C.F.R. § 1508.25(a)(3).

In addition to this proposal at the Port, and the numerous fossil fuel projects listed above, NW Innovation Works itself is also proposing two essentially identical plants at Port Westward, near Clatskanie, Oregon, and at the Port of Tacoma, Washington. The Port and FERC must consider the impacts of each of these projects when combined under the requirements to consider connected and similar actions that contribute to cumulative effects of the proposed methanol export facility. In particular, the Port should consider:

- Increased vessel traffic on the Columbia River, including navigational and maritime safety concerns that will result if all three projects move forward
- Challenges in protecting water quality, including the increased risk of spill in the Columbia River that will result if all three projects move forward
- Emissions of air pollutants, including diesel particulate, greenhouse gases, fugitive emissions, and hazardous air pollutants that will result if all three projects move forward

[12] Combining all the vessels from the various projects (730+125+365+115+208 = 1543)

- Increased vehicle traffic to the Port and surrounding areas, including increased noise and delays

The Port and FERC must consider the impacts of NW Innovation Works' three proposals together as connected, cumulative, or similar actions. *See Kleppe v. Sierra Club*, 427 U.S. 390, 409 (1976) ("when several proposals for coal-related actions that will have cumulative or synergistic environmental impact upon a region are pending concurrently before an agency, their environmental consequences must be considered together").

Programmatic EIS

In the alternative, the Port and FERC should consider preparing a programmatic EIS to better account for the cumulative impacts of numerous pending methanol export facilities proposed by NW Innovation Works. The significant regional, national, and international impacts that will result from these terminals and the related activities weigh in favor of a programmatic EIS to discuss and analyze these impacts together with the alternatives. *See, e.g.*, *LaFlamme v. Federal Energy Regulatory Commission*, 852 F.2d 389, 401-02 (9th Cir. 1988) (holding that where several foreseeable similar projects in a geographic region have a cumulative impact, they should be evaluated in a single EIS); *see also City of Tenakee Springs v. Block*, 778 F.2d 1402, 1407 (9th Cir. 1985) (holding that where there are large scale plans for regional development, NEPA requires both a programmatic and site-specific EIS). Here, the numerous methanol export facilities and related pipeline infrastructure proposed by NW Innovation Works are foreseeable similar projects in the same geographic region and thus should be considered in a single, programmatic EIS.

Conclusion

Thank you for your consideration of these scoping comments. Commenters look forward to reviewing the draft EIS that contains a full assessment of the direct, indirect, and cumulative impacts that are likely to result from the proposed methanol export facility along the Columbia River.

Sincerely,

Marla Nelson
Staff Attorney, NEDC

Kelsey Herman
Project Coordinator, NEDC

Lauren Goldberg
Staff Attorney, Columbia Riverkeeper

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
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December 20, 2012

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary, Federal Energy Regulatory Commission
888 First St., N.E., Room 1A
Washington, D.C. 20426

Re: National Marine Fisheries Service (NMFS) Comments on Notice of Intent for the Oregon LNG Export Project, Oregon (Docket No. PF12-18-000) and Washington Expansion Project, Washington (PF12-20-000)

Dear Ms. Bose:

The National Marine Fisheries Service (NMFS) has reviewed the notice of intent (NOI) issued by the Federal Energy Regulatory Commission (FERC) for the subject project.[1] The NOI solicited input on the proposed project's potential environmental effects, possible alternatives to the proposed project or portions of the project, and recommendations to avoid or lessen environmental impacts.

NMFS' comments contained herein have been prepared in accordance with FERC's request. They are based on NMFS' current understanding of the proposed project. NMFS reserves the right to raise additional issues after the project has been more completely defined.

Proposed Action Under Docket Number PF12-18-000. Oregon LNG is seeking a license to construct, operate, and maintain an onshore liquefied natural gas (LNG) export and storage terminal near the mouth of the Skipanon River at approximately river mile 11 of the Columbia River. A new pipeline is proposed for construction beginning at milepost (MP) 47.5 of the Oregon Pipeline and terminating at the Williams Northwest Pipeline Interconnect near Woodland, Washington, and a new compressor station at MP 81 of the new pipeline. The pipeline will be approximately 39 miles long. LNG will depart at the terminal via tankers to overseas sources.

[1] Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Oregon LNG Export Project and Washington Expansion Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings, September 24, 2012.

Proposed Action Under Docket Number PF12-20-000. Northwest Pipeline GP (Northwest) is seeking a license to construct and operate the Washington Expansion Project (WEP). The WEP is a capacity expansion of Northwest's natural gas transmission facilities along the Interstate 5 corridor in the State of Washington. The WEP will include the installation of approximately 140 miles of pipeline loop in 10 noncontiguous segments in Washington between Sumas and Woodland.

NMFS's Authority. The participation of NMFS in the FERC license process stems from the agency's responsibility to manage, conserve, and protect marine and coastal living resources as provided for under the following statutes:

1. Magnuson-Stevens Fishery Conservation and Management Act (MSA)
2. Endangered Species Act (ESA)
3. Marine Mammal Protection Act (MMPA)
4. Fish and Wildlife Coordination Act (FWCA)
5. National Environmental Policy Act (NEPA)
6. Reorganization Plan No. 4 of 1970
7. Natural Gas Act

Potentially Affected Species. Aquatic environments and ecosystems within the proposed action area provide important habitats for many of NMFS' trust resources, including species and habitats protected under Federal legislation. NMFS has authority under the above statutes, and others, to provide conditions to the Commission to protect and conserve all marine and anadromous fish and their supporting habitat, potentially adversely affected by the proposed project.

Listed below are anadromous fish species, marine mammals, and marine turtles under NMFS' jurisdiction that are listed under the ESA. Available information indicates that 17 ESA-listed anadromous fish species, three marine fish species, seven marine mammal species, and four marine turtles. Additionally, EFH and Habitat Areas of Particular Concern (HAPCs) may be affected by the proposed project, though final alignment of the pipeline may alleviate concerns for some of these species and their habitats.

Anadromous Fish
Lower Columbia River Chinook salmon (*Oncorhynchus. tshawytscha*) - threatened
Upper Willamette River spring-run Chinook salmon (*O. tshawytscha*) – threatened
Upper Columbia River spring-run Chinook salmon (*O. tshawytscha*) - endangered
Snake River spring/summer run Chinook salmon (*O. tshawytscha*) - threatened
Snake River fall-run Chinook salmon (*O. tshawytscha*) - threatened
Columbia River chum salmon (*O. keta*) - threatened
Lower Columbia River coho salmon (*O. kisutch*) - threatened
Snake River sockeye salmon (*O. nerka*) - endangered
Lower Columbia River steelhead (*O. mykiss*) - threatened
Upper Willamette River steelhead (*O. mykiss*) - threatened
Middle Columbia River steelhead (*O. mykiss*) - threatened
Upper Columbia River steelhead (*O. mykiss*) – endangered

Snake River Basin steelhead (O. *mykiss*) – threatened
Southern DPS North American green sturgeon (*Acipenser medirostris*) - threatened
Southern DPS Eulachon (*Thaleichthys pacificus*) – threatened
Puget Sound Chinook (*O. tshawytscha*) – threatened
Puget Sound Steelhead (*O. mykiss*) – threatened

(Critical habitat has been designated for all salmonids listed above except Lower Columbia River coho salmon, and Puget Sound steelhead)

Marine Fish Species
Yelloweye rockfish (*Sebastes ruberrimus*) - threatened
Canary rockfish (*S. pinniger*) - threatened
Bocaccio rockfish (*S. paucispinis*) - threatened

Marine Mammals
Southern resident killer whale (*Orcinus orca*) - endangered
Humpback whale (*Megaptera novaeangliae*) – endangered
Blue whale (*Balaenoptera musculus*) – endangered
Fin whale (*Balaenoptera physalus*) – endangered
Sei whale (*Balaenoptera borealis*) – endangered
Sperm whale (*Physeter macrocephalus*) – endangered
Steller sea lion (*Eumetopias jubatus*) - threatened
(For the above marine mammals, critical habitat has been designated for the Steller sea lion and Southern resident killer whale)

Marine Turtles
Leatherback sea turtle (*Dermochelys coriacea*) – endangered
Loggerhead sea turtle (*Caretta caretta*) – threatened
Green sea turtle (*Chelonia mydas*) – endangered
Olive Ridley sea turtle (*Lepidochelys olivacea*) – endangered
(For marine turtles, critical habitat has been designated for Leatherback and Green sea turtles)

Essential Fish Habitat
The Pacific Fisheries Management Council, which was established under the MSA, described and identified essential fish habitat (EFH) in each of its fisheries management plans. EFH includes "those waters and substrates necessary to fish for spawning, breeding, feeding, or growth to maturity." All aquatic habitat in Washington, Oregon, and California and within the U.S. West Coast exclusive economic zone (200 miles), that was historically accessible to groundfish species; coastal pelagic species; highly migratory species; and coho, pink, and Chinook salmon managed by the Pacific Fisheries Management Council is designated EFH. More detailed information on EFH can be found on our web site at: http://www.nmfs.noaa.gov/habitat/habitatprotection/efh/index.htm.

There are 63 species of groundfish for which EFH is recognized under the MSA, five species of coastal pelagic species, 13 species of highly migratory species, and three species of Pacific salmon.

Habitat Areas of Particular Concern

Essential Fish Habitat guidelines further identify habitat areas of particular concern (HAPCs) as types of habitat *within* EFH that, in brief, provide: (1) Particularly important ecological function, (2) are particularly sensitive to human-induced degradation, (3) are particularly sensitive to development activities, and/or (4) are particularly rare. The designated groundfish HAPCs that may overlap with the project alignment or otherwise be affected include: (1) Estuaries, (2) canopy kelp, (3) seagrass, and (4) rocky reefs. In addition, all Washington State waters shoreward to the MHHW are designated HAPCs. HAPCs include all waters, substrates, and associated biological communities falling within the areas defined above.

For salmon, no HAPCs have been formally designated, but the broader definition of EFH would include all freshwaters used for migration, spawning and feeding, hence, would capture all alignments crossing fluvial systems.

Marine Mammal Protection Act (MMPA)

Regardless of whether they are endangered or threatened, all marine mammals are protected under the MMPA. In addition to Steller sea lions, the lower Columbia River also contains foraging and resting areas for resident harbor seals and seasonal migratory California sea lions. If the applicant anticipates taking of marine mammals, a small take authorization or incidental harassment authorization should be sought under section 101(a)(5) of the MMPA, to avoid taking in violation of the statute. More information on the MMPA may be found on our website at: http://www.nmfs.noaa.gov/pr/laws/mmpa.

Structure of Comments. The comments highlight issues of concern to NMFS that the Commission should analyze during the environmental review of this project, as well as provide conservation recommendations for FERC's consideration. They are organized into general categories based on the various stages of project development: (1) Siting, (2) planning/design, (3) construction, (4) operation, (5) impact analysis, (6) monitoring, (7) mitigation, and (8) information needs and consultation timing. Some comments are applicable to multiple categories and FERC therefore should address the comprehensive intent of each comment rather than solely the category within which it is presented.

1. Siting of LNG Terminals

The location of LNG terminals, and associated infrastructure, will influence the type and magnitude of impacts on aquatic resources. The Commission should follow these recommendations with regard to import terminal siting to mitigate for project effects on marine and anadromous resources.

A. Site LNG new terminals as far offshore as feasible, in locations of lower biological productivity, and away from sensitive habitats and migration routes of marine mammals or protected migratory species.

B. Site LNG terminals and associated pipeline networks to avoid or minimize construction and operation impacts on marine mammals, marine and anadromous fish, ESA-listed species, ESA-designated critical habitats, EFH, estuaries, wetland and shallow water habitats, and fishing areas.

C. Site LNG terminals to maximize the use of existing viable infrastructure such as existing pipeline networks, and deep draft berthing areas.

D. Site LNG terminals to minimize conflicts with current activities such as recognized spawning or nursery areas, areas where fishing gear is deployed, navigation channels, and research use areas.

E. Minimize vessel use of confined waterways. Vessel passage in confined waterways can cause erosion of shoal water areas, resuspend sediment from the channel bottom, strand juvenile salmonids on riverbanks, and contribute to shoreline erosion.

F. Minimize the area of dredging and amount of resulting depth change. Dredging and the disposal of dredged material can cause substantial impacts on many aquatic organisms and their habitats. The permanent removal of material from the aquatic environment may interfere with sediment routing and habitat forming processes, and contribute to shoreline erosion.

G. Resource evaluation surveys of the proposed site should include information comparing and contrasting the relative aquatic resource impacts of alternate LNG sites and associated infrastructure. The effort should consider and include information and analysis regarding: Marine mammals, marine, estuarine, and anadromous fish, endangered/threatened species, ESA critical habitat, EFH and HAPCs, impacts to the function and value of these habitats; local fishing activity; the type of federally-managed fish species that may be impacted; potential cumulative impacts; a consideration of how climate change may affect those impacts; and the possibilities of interconnecting with existing facilities (*e.g.*, location of existing pipelines, heat sources, and other viable infrastructure) that the applicant could potentially utilize. The analysis should also consider the duration of identified species and habitat impacts.

H. Provide a reasonable range of alternate locations for the siting of the LNG terminal as part of the alternatives analyzed pursuant to NEPA. The analyses of these alternate sites should be comprehensive to allow for a meaningful comparison among the sites. The alternatives analysis should consider all potential sites within the expected service area (*e.g.*, west coast of North America) regardless of whether a project proponent has filed with FERC for authorization to construct a facility on the site.

2. Planning/Design

A. For on- or near-shore LNG export facilities, NMFS recommends a closed-loop liquefaction system designed to use waste heat from existing power plants or other industrial facilities. Such a system precludes the combustion of additional hydrocarbons to liquefy LNG, thereby reducing potential air pollution impacts[2] and impacts to the

[2] Refer to U.S. EPA. 2004. Technical Development Document for the Proposed Section 316(b) Rule for Phase III Facilities, EPA-821-R-04-015, November 2004. Available at: http://www.epa.gov/waterscience/316b/ph3.htm.

aquatic environment. For similar reasons, NMFS encourages the consideration of non-emission heat sources, such as using solar technology to reheat water used in the gasification process. NMFS recommends reducing effects to air and water quality from the removal of CO_2, sulfur compounds, mercury, and heat during the liquefaction process.

B. Reduce environmental effects by preferentially placing infrastructure in previously disturbed upland areas with low restoration value, minimizing the facility footprint, and siting and designing the vessel wharf and turning basin to minimize the need for dredging, including maintenance dredging. Similarly, design pipeline alignments to use previously disturbed upland areas, avoid or minimize disturbance in riparian areas, and co-locate or combine with other existing or proposed pipelines where possible.

C. Avoid illuminating aquatic areas that may cause changes in behavior or increase risk to living resources, or modify value or function of their habitat.

3. Construction

NMFS's preliminary recommendation is that the following actions and measures are needed to mitigate for the effects of construction of LNG terminals and associated infrastructure.

A. Pollution: Conservation measures include, but are not limited to: (1) Requiring a hazardous materials spill response plan for the handling, storage, and transportation such materials; (2) testing soils and substrates for existing contaminants; (3) controlling and removing contaminants; (4) avoiding or minimizing discharge of waste water from terminal or vessels that is chemically or physically (*e.g.*, temperature) dissimilar from receiving waters; and (5) avoiding use of materials that pose contaminant risks to critical habitat, EFH, and associated fisheries (*e.g.*, creosote pilings).

B. Sensitive habitats: The design and construction methodology for building the terminal and associated infrastructure should aim to prevent and/or minimize impacts to wetland, shallow water, riparian, nursery, and stream habitats. Habitat conversion through direct loss or reduced ecological function of sensitive areas should be avoided. Activities of particular interest for this project include, but are not limited to, wetland filling, dredging of a mooring basin, bank protection, water withdrawals and discharges, pipeline routing, riparian vegetation management, wharf construction, and vessel operations.

C. Pipeline: Pipeline construction should minimize damage to aquatic resources by selecting an alignment that minimizes waterway and wetland crossings and riparian vegetation removal. This is particularly the case for waterways designated as critical habitat or EFH. For waterways crossed using an open-trench technique, habitat restoration and fish salvage plans should be developed. The maintenance and construction of roads accessing the pipeline should be reviewed for impacts on wood recruitment, sediment delivery, and stormwater runoff.

D. Dredging: The lower Columbia River estuary provides vital habitat for anadromous salmonids throughout the Columbia River basin, and is of particular importance from a threatened and endangered species recovery perspective. The estuary is designated as critical habitat for 17species of ESA-listed fish and EFH for Pacific salmon.

   The following should be included in the project's environmental impact statement (EIS) to assess impacts to this important habitat: (1) Area, depth, volume, sediment character of the dredge footprint, including discrete samples characterizing the expected leave surface (*i.e.*, z-layer), and anticipated frequency and seasonality of maintenance dredging; (2) the anticipated suspension and deposition of sediments outside of the dredging footprint; (3) placement options of dredged materials, with preference for beneficial use; and (4) river hydraulic model results to assess future changes in hydraulic patterns and channel morphology on site and within the impacted river reach over time, and to estimate maintenance dredging requirements. In order to protect rearing habitat, NMFS recommends minimizing the dredge area required for the turning basin to the extent possible. Similarly, dredging of shallow water areas should be avoided. The use of scientifically based seasonal "construction windows" should be used to minimize loss of habitat functions and values and the resources that might be harmed or displaced by dredging activities.

E. Noise: Efforts to minimize sound from construction and operation activities should be considered, particularly when sensitive aquatic resources are likely to be present. When unable to avoid species presence, use sound attenuating methods to minimize adverse impacts (*e.g.*, bubble curtains). The use of vibratory or boring systems to set piles has been shown to greatly reduce or eliminate shock wave releases associated with pile driving using the "drop hammer" technology.[3] However, boring is not typically encouraged due to water quality concerns. Underwater blasting should be avoided.

F. Stormwater management: Include impacts of altered stormwater quality and quantity entering aquatic habitats due to new structures. Minimizing the construction of impervious surfaces, which increase runoff and sediment load into aquatic habitats, is recommended. Where adverse impacts on aquatic habitat cannot be avoided, incorporate conservation measures into the project design to minimize the impact (*e.g.*, stormwater swales, compost-amended chelation).

4. Operation

The operation of LNG terminals may impact aquatic resources in a variety of ways. The following information will be considered by NMFS when providing recommendations for mitigation measures for the operation of LNG terminals.

A. Vessel Traffic: LNG terminals will increase vessel traffic as a result of transport operations. NMFS is concerned with the number of ships, the size of the ships, and their routes. The increase in vessel traffic may result in sediment resuspension and deposition,

[3] Refer to Sonalysts, Inc. 1996. Acoustic measurements during the Baldwin Bridge Demolition. Prepared for CT DOT. Sonalysts, Inc. 215 Parkway North, Waterford, CT, (to be posted on the web).

contaminant exposure, increased sound, juvenile salmon wake strandings, and marine mammal vessel strikes. Vessel operation guidelines should be proposed that minimize impacts.

B. Water Withdrawal and Discharge: Impacts associated with water withdrawal/discharge during construction (*e.g.*, hydrostatic testing) or operation (*e.g.*, ballast water exchange including the spread of invasive species and liquefaction of natural gas) should be minimized:
   1. Limit the volume of water withdrawals and withdraw water when and where the impacts of entrainment and impingement of aquatic organisms will be minimized (*e.g.*, off temporal and spatial abundance peaks).
   2. Use specialized technology to minimize impacts of water intake structures and their operation on aquatic organisms. Refer to NMFS' general screening criteria.[4] To assist in evaluating the effects of specific applications, water intake structure designs should be submitted to NMFS for review and comment early in the design phase.
   3. For systems discharging to aquatic habitat, avoid the use of biocides (*e.g.*, sodium hypochlorite) to control biofouling and implement least damaging antifouling alternatives.
   4. Follow regulations for ballast water exchange that will aid in controlling the introduction and spread of invasive species from ship' ballast water.
   5. Water temperatures within the discharge plume should be comparable to the receiving waters. Where temperature disparity cannot be avoided, the discharge plume should not exceed the thermal tolerance of plant and animal species living in the receiving water body. Water quality should meet or exceed all relevant local, state, and Federal standards.

C. Maintenance Dredging: Refer to Section 3 of this letter: *Construction of LNG Terminals*.

D. LNG Spill: Collision, grounding, or breach of an LNG tanker is a concern to NMFS due to the large area that could be impacted by such an event[5] and the resulting effects on NMFS trust resources and their critical habitats. Impacts to be considered and that need to be addressed by conservation measures include direct mortality to individuals, altered migration, and reduction or loss of forage and rearing habitat, prey availability, and water quality.

5. Impact Analysis

To ensure the adequate evaluation of effects on NMFS' trust resources, NMFS will need the following information when reviewing biological, economic, and cumulative impact analyses. During the application and NEPA document stages, biological analyses need to include, but are not limited to:

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[4] NMFS' screening criteria is available on-line at http://www.nwr.noaa.gov/Publications/Reference-Documents/Passage-Refs.cfm.

[5] Sandia National Laboratories. 2004. Sandia Report: Guidance on Risk Analysis and Safety Implications of a Large Liquid Natural Gas (LNG) Spill Over Water. SAND2004-6258.

A. A list of direct, indirect, and cumulative biological impacts resulting from physical, chemical, and biological changes on the environment arising from facility construction, water intake, thermal pollution, discharges, pipe laying, dredging, vessel operations, etc. including a comprehensive and detailed analysis of potential impacts. Impact estimates should include:

   1. Impacts to listed and protected species at the individual and population-levels;
   2. The extent of impacted critical habitats, EFH and other marine and coastal habitats;
   3. Impacts on fisheries production;
   4. Population-level impacts on MSA-managed species taking into account their interrelationships at both the habitat and the food web level;
   5. Potential to reduce anticipated impacts by incorporating additional conservation measures.

B. A description of any incomplete or unknown information, with an explanation of its relevance in evaluating reasonably foreseeable significant adverse impacts on the aquatic environment and when sufficient detail will be available to inform an assessment of adverse impacts.

C. Site-specific impact analysis studies should be conducted for all water crossing alignments. NMFS should be consulted to identify acceptable alternative data sets/studies or other impact assessment tools when conducting these analyses. In the absence of site-specific information that is needed to conduct an analysis of effects to NMFS' trust resources, NMFS will give the benefit of the doubt to ESA-listed species, designated critical habitat, and EFH.

D. A description and rationale of the methods used in models that estimate project impacts on aquatic resources. This description and rationale should include the assumptions made for the model, as well as any model verification and sensitivity analysis.

E. In addition to utilizing the best available information, a description of data uncertainty and variability including uncertainty ranges and appropriate sensitivity analyses should be provided.

F. In the absence of site-specific information that is needed to conduct an analysis of effects to NMFS' trust resources, NMFS will give the benefit of the doubt to ESA-listed species, designated critical habitat, and EFH.

Economic analysis should include:

G. An estimation of potential monetary losses incurred by both commercial and recreational fisheries and fishing communities due to the proposed project as well as for other existing and foreseeable LNG projects within the same geographic area.

Cumulative impact analysis should include:

H. A description of any impacts to other existing aquatic uses.

I. A description of all sources of impacts (past, present and reasonably foreseeable) on aquatic resources present within the action area of the proposed LNG project and a consideration of how climate change may affect those impacts. Of particular interest to NMFS is the disturbance associated with terminal construction, pile driving, and pipe laying; terminal operations, including water withdrawals and discharges; increased vessel traffic and dredging; total water utilization in the basin; and the associated impacts on the aquatic environment. Special attention should be given to the cumulative impacts associated with the construction and operation of multiple LNG terminals within an impacted region and alternatives explored that co-locate or replace redundant systems. The area considered for the cumulative impacts analysis should be determined according to particular geographic, environmental, and biological characteristics (*e.g.*, presence/absence of physical or geographic barriers, currents, and highly migratory species), which might impact the propagation of impacts from multiple LNG terminals. Information that should be considered in a cumulative impact analysis includes the number of existing, proposed, and planned LNG terminals; their location; project specific details (*e.g.*, open-loop vs. hybrid or closed-loop system); and fishery resources at risk.

J. Impact area boundaries that are broad enough to consider the direct/indirect impacts on living aquatic resources and habitats.

6. Monitoring and Adaptive Management

Monitoring programs should be developed to: (1) Provide baseline information; (2) assess real impacts over time and verify the accuracy of estimated impacts; (3) provide the information necessary for the development of successful mitigation efforts; and (4) allow necessary changes in project design (*e.g.*, system retrofit) or operation as part of an adaptive management strategy. As such, the proposed project should include an adaptive management strategy developed in partnership with the appropriate local, state, and Federal agencies and tribal governments.

7. Compensatory Mitigation

The mitigation plan should be modified to reflect changes in the proposed action. In addition to the mitigation plan under Docket Nos. CP09-6-000 and CP09-7-000, the mitigation should include measures needed to address the additional effects of the larger export facility footprint, the additional 39-mile pipeline in Oregon, and the additional 140-mile pipeline in Washington.

Effects on resources managed by NMFS should be avoided, especially if the resources are irreplaceable, essential, and limited. Unavoidable impacts that are not irreplaceable, essential, and limited should be minimized. If impacts to resources managed by NMFS cannot be avoided, or not minimized as much as needed, compensatory mitigation should be implemented to offset adverse impacts or unavoidable losses to aquatic resources from authorized activities as stipulated under NEPA's implementing regulations [40 CFR Part 1505.2 (c), 1502.14, and

1502.16]. To be considered, compensatory mitigation must be reasonably certain to occur by providing assurances that proposed mitigation measures can be implemented (*e.g.* identifying specific mitigation projects and locations, demonstrating rights to use property for the Oregon LNG project mitigation, assurance that the necessary permits can be obtained.). Recommended best practices for mitigation include, but are not limited to:

A. A mitigation plan that provides for the replacement of lost resources and habitat functional values. Mitigation plans should be developed to create or restore the same type of habitat impacted and benefit the same species and populations impacted. Temporal and spatial aspects should be addressed to avoid or minimize disparity between impacted and replacement resources or habitats.

B. A process that allows for adaptive management through retrofitting and uses more effective operational practices to further minimize impacts as new techniques are developed.

8. Information Needs and Consultation Timing

A. NMFS' information needs regarding the ESA, MSA, and MMPA are much more detailed than what FERC has indicated as sufficient for FERC's application and EIS. To the maximum degree possible, NMFS encourages FERC and the applicant to work collaboratively with us to meet our information needs and resolve the majority of issues during the pre-filing process to avoid delays during FERC's formal project review period.

B. Furthermore, NMFS requests clarification of the BA and EIS relationship and timing. NMFS recommends that FERC initiate ESA and EFH consultation after completion of the FEIS. Thus, any proposed action changes that occurred from the public comments can be incorporated into the BA.

NMFS appreciates the opportunity to comment at this time. Please direct questions regarding this letter to Mischa Connine for the Oregon LNG Export Project of the Willamette/Lower Columbia River Branch of the Oregon State Habitat Office at 503.230.5401. Please contact Jeff Fisher for coordinating NMFS technical support for Washington Expansion portion of the project at 360.534.9342.

Sincerely,

Kim W. Kratz, Ph.D.
Director, Oregon State Habitat Branch
Habitat Conservation Division

Enclosure: Certificate of Service

cc: Doug Young (FWS)
James Holm (Corps)
Peter Olmstead (Corps)
Yvonne Vallette (EPA)
Elizabeth Ruther (ODFW)
Chris Knutsen (ODFW)
Mike McCabe (ODSL)
Jennifer Purcell (ODEQ)

Service List

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Oregon LNG	**) FERC Docket Nos. PF12-18-000 and PF12-20-000 (Oregon LNG Export Project and Washington Expansion Project)**
	)
Application for Subsequent Preliminary Permit	**)**
	)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, by electronic mail, a letter to Kimberly D. Bose, Federal Energy Regulatory Commission, the National Marine Fisheries Service's Notice of Intervention, and this Certificate of Service has been served by first class mail or electronic mail to each person designated on the official service list compiled by the Commission in the above captioned proceeding.

Dated this 20th day of December, 2012.

Mischa Connine
Oregon State Habitat Office
National Marine Fisheries Service

EMISSIONS OF CRITERIA POLLUTANTS, TOXIC AIR POLLUTANTS, AND GREENHOUSE GASES, FROM THE USE OF ALTERNATIVE TRANSPORTATION MODES AND FUELS

UCD-ITS-RR-96-12

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January 1996

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1.O OVERVIEW

Policy makers in transportation often make investment decisions involving hundreds of millions of dollars. Typically they evaluate a wide range of alternatives -- from expanding highway capacity to managing existing demand to building a new rail line -- with respect to a broad array of seemingly incommensurable criteria. In theory, a policy maker can evaluate alternatives by cost-benefit analysis, in which one quantifies and monetizes all of the costs and benefits to society, and picks the alternative that yields the greatest net present-value of benefits. In this report, we quantify a key component of the social-cost part of cost-benefit analysis: emissions of air pollutants from different transportation modes.

The full social cost of a transportation mode consists of two major components: 1) capital and operating costs paid for in dollars by users, and 2) all other costs that result from the use of the transportation mode but which are not paid for directly in dollars by users. Some examples of this second kind of cost are: the health effects of air pollution from the combustion of transportation fuels; damages to marine ecosystems from oil spills; Federal subsidies to the construction of mass transit systems; and the costs to society of adapting to climate changes wrought by emissions of greenhouse gases. Preliminary analyses have indicated that the dollar value of the health effects of air pollution is one of the largest of these external costs of transportation (McCubbin and Delucchi, 1995). The CEC will include the cost of air pollution in its analysis and comparison of the social cost of alternative transportation modes.

There are five steps in the estimation of the dollar value of the health effects of emissions of air pollutants: 1) estimate emissions of harmful pollutants; 2) estimate the change in air quality resulting from the emissions; 3) estimate exposure to the polluted air; 4) estimate the health effects resulting from exposure; and 5) estimate the monetary value of the health effects. *This analysis is concerned with the first of these five steps: we estimate emissions of criteria pollutants, toxic air pollutants, and greenhouse gases from alternative transportation modes.*

1.1 Transportation modes

We analyze the following five modes:

- single-occupant automobiles
- carpools and vanpools
- buses
- light-rail trains
- at-grade and underground heavy-rail systems (including commuter rail)

1.2 Fuels and propulsion systems

For private automobiles, vans, and buses, we consider several different kinds of fuels and propulsion technologies:

- methanol made from coal, natural gas, or biomass, and used in internal-combustion-engine vehicles (ICEVs) or fuel-cell electric vehicles (FCEVs)

- compressed or liquefied natural gas used in ICEVs

- ethanol made from fermentation of corn (using coal to provide process energy) or from lignocellulosic biomass, and used in ICEVs

- liquefied petroleum gases from crude oil or natural gas processing, and used in ICEVs

- electricity for battery powered vehicles, considering several conventional and advanced sources of electricity generation.

1.3 Criteria air pollutants, toxic air pollutants, and greenhouse gases

Our analysis includes emissions of all the so-called “criteria” air pollutants:

- volatile organic compounds (VOCs)

- carbon monoxide (CO)

- oxides of nitrogen (NOx)

- oxides of sulfur (SOx)

- particulate matter (PM; including small-diameter PM_{10}, in some cases)

We also estimate emissions of the toxic air pollutants for which there are reliable data: in most cases, benzene, formaldehyde, aldehydes, and 1,3-butadiene. However, in many cases there are no data on toxic emissions.

Finally, we use the model developed by DeLuchi (1991, 1992) to estimate emissions of all direct and indirect greenhouse gases:

- carbon dioxide (CO_2)

- methane (CH_4)

- nitrous oxide (N_2O)

- carbon monoxide (CO)
- non-methane hydrocarbons (NMHCs)
- nitrogen-oxides (NO_X)

We do not include emissions of chlorofluorocarbons (CFCs) because under international agreements these are being phased out. We convert mass emissions of all the non-CO2 gases to the mass amount of CO2 that would have an equivalent warming effect, using conversion factors (called "Global Warming Potentials," or GWPs). We estimate emissions from the entire fuel-production and use system.

1.4 Stages of the fuelcycle

We estimate emissions from several stages or points in the entire “lifecycle” or “fuelcycle” of a transportation mode:

- Transforming a primary resource into a finished fuel (e.g., electricity production, petroleum refining, methanol production)
- Distributing and storing liquid fuels (e.g., at petroleum bulk plants) (except that we do not include tailpipe emissions from tanker trucks)
- Using a finished fuel in vehicles or power plants
- Using, servicing, and maintaining non-revenue vehicles, highway infrastructure, and support buildings (maintenance vehicles, administrative buildings, train stations, gasoline service stations, petroleum bulk plants, highways, parking lots, and so on). We have developed original, up-to-date estimates of energy use and emissions of the motor-vehicle infrastructure.

We do not estimate emissions from the construction of vehicles, facilities, or guideways, because these are one-time emissions that cannot be added to the ongoing emissions from system operation, and because the energy-use and emission-factor data in any event are quite poor.

1.5 Energy use

Fuelcycle emissions of CO_2, emissions from power plants, emissions from petroleum refining, and emissions from other sources are a function of the amount and kind of energy consumed by cars, buses, trains, and power plants. We have modeled this energy consumption in detail, using real-world data and sophisticated models:

- We use a detailed engineering model (Ross, 1994; An and Ross, 1993; Ross and An, 1993), to calculate energy use by passenger cars and vans as a function of characteristics of the trip (average speed, maximum speed, number of stops per mile, number of cold starts, and more) and characteristics of vehicles (empty weight, number of passengers, rolling-resistance coefficients, frontal area, drag coefficient, component efficiencies, energy use by accessories, use of regenerative braking, and other factors). This model enables us to represent properly the difference between the energy use of a short trip by car to a train station, and the energy use of a longer door-to-door commute trip by car.

- We had the California Energy Commission program its Elfin electricity model to calculate the amount and mix of fuels that would be used to generate the incremental electricity consumed by electric light-rail and heavy-rail transit systems. These estimates of "marginal" electricity use are in principle more accurate than the more commonly used estimates of "average" electricity use.

- Energy use by transit stations and transit maintenance activities are actual consumption data reported to us by utility managers and accountants of transit systems in Sacramento, San Francisco, Los Angeles, San Diego, Boston, and Washington, D. C.

- Energy use by trains and buses are actual energy use data reported by transit districts to the U.S. Federal Transit Administration of the U.S. Department of Transportation.

We also have considered energy use for fuel production and other activities, relying on the work of DeLuchi et al. (1992), DeLuchi (1991), and others.

1.6 Emission factors

We used the best available models and data sources to calculate emission factors for motor vehicles, power plants, petroleum refineries, and other sources.

- We use output and equations from CARB's EMFAC emissions model, and raw data on motor-vehicle emissions at each "stage" of the driving cycle, to develop a model that calculates gram / mile emission factors for petroleum and alternative-fuel vehicle as a function of trip length, ambient temperature, number of cold starts, and other factors. This model enables us to represent properly the difference between the emissions of a short trip by car to a train station, and the emissions of a longer door-to-door commute trip by car. The EMFAC model accounts for the emission standards in effect for each model-year vehicle.

- We estimate emissions from petroleum refineries as a function of fuel input, product output, emissions from individual process areas, and other factors, using data from the California Energy Commission (1992), the U.S. Environmental Protection Agency (AP-42, 1994), the California Air Resources Board (August 1991), the Energy Information Administration, and other sources. We estimate separate emission factors for gasoline, diesel, and residual fuel-oil. For methanol and ethanol production, we reviewed and analyzed the existing literature to obtain the most reliable estimates of emissions of criteria pollutants from advanced facilities with emission controls.

- We use emission factors from the CEC's Elfin model and the U.S. EPA's emission-factor handbook (EPA, 1994) to estimate emissions from power plants. We assume that controls are used to comply with the requirements of the 1990 Clean Air Act Amendments.

- We estimate emissions of toxic air pollutants on the basis of toxic-emission inventory data supplied by the California Air Resources Board (1993), and emission factors from the EPA's emission-factor handbook (EPA, 1994) and the EPA's toxic-emissions data base.

- To calculate fuelcycle greenhouse-gas emissions, we use the year-2000 emission factors calculated by the greenhouse-gas emissions model developed by DeLuchi (1991). This model estimates CO_2-equivalent emissions of all greenhouse gases from all stages of the fuelcycle, for a wide variety of alternative fuels.

1.7 Door-to-door trips

We express the emissions results in two ways: as grams of each pollutant emitted per passenger-mile of travel by each transportation mode, and as grams of each pollutant emitted during a complete door-to-door trip involving one or two modes. We assume that single-occupant autos, carpools, and vanpools go door to door directly. However, buses and trains do not go door to door; a traveler must walk, ride a bus, or drive from his door to the bus stop or rail station. Thus, for trips by bus or train, we include emissions from the use of the mode of access to the bus or train.

We use data from the *1991 Statewide Travel Survey* (Caltrans, 1993) and other sources to model how travelers get from their home to the bus stop or train station. We use estimates by the Congressional Budget Office (1977) of the length of the mode of access and the "circuity," or extra travel distance, of all trips relative to a baseline trip by a single-occupant automobile. The length and type of access is important, because a short access trip by an automobile can generate nearly as much pollution as a much longer door-to-door trip by automobile.

1.8 Metropolitan areas

Many of the factors that affect emissions from transportation modes vary from city to city. Among these city-specific factors are: load factors for transit systems; the technical characteristics of transit systems; the typical mode of access to transit systems; average traffic speeds; average temperature; emission regulations affecting vehicles and service stations; and the maintenance characteristics of systems. Because of this variability, it is more useful to the do the analysis for individual regions or metropolitan areas, rather than for the nation as a whole. We consider six metropolitan regions in this analysis:

- San Francisco
- Sacramento
- Los Angeles
- San Diego
- Boston
- Washington, D. C.

We have used city-specific data to the extent possible. For example, we surveyed transit operators in these regions directly to find out how much energy they used to maintain and service their systems. We also have detailed cost and ridership figures for all transit systems in the United States (Urban Mass Transit Administration, Section 15 reports, annual).

We will target our analysis for the years 2000-2005. This means that we will consider vehicle and fuel technology, emission factors, and energy-intensiveness factors appropriate for the period 2000 to 2005.

1.9 Relation to the larger social-cost analysis: inputs and outputs

The emissions results produced here can be linked to both transportation and land-use models and air quality models, as part of an analysis of the social cost of transportation modes. For example, an analyst first could use a model such as MINUTP to determine how transportation and land-use policies might change regional travel patterns. Then, with some assumptions about the use of alternative fuels and technologies, the analyst could apply the emission factors estimated in this project to arrive at regional emissions. The regional emissions then could be input to an air quality model, to determine the effect of the transportation and land-use policy on regional air quality.

1.10 Factors not considered

Our results -- grams/mile for each mode, and grams/trip -- cannot by themselves be used to estimate the emissions impacts of policies that add or improve transportation services. In order to analyze properly the environmental impacts of transportation policies, one must know, in addition to per-trip emission factors, the overall effect of the policy on transportation demand. That is, one must model the net change in automobile trips, bus trips, and so on, that result from a particular policy (see section 1.8 above). Obviously, the net emissions impact of, say, a new rail line depends greatly on the proportion of projected riders that would drive versus the proportion that would ride in a carpool or vanpool versus the proportion that would take a bus versus the proportion that would not travel at all, were the rail line not built. The greater the fraction of riders that would drive alone were the new line not built, the greater the emissions impacts. We do not analysis these modal impacts in this analysis. Curry (1976) summarize several studies of the previous modes of new transit passengers.

New transportation services also can affect the flow the of traffic indirectly. For example, buses can impede automobile traffic (Cohen et al., 1978) and thereby cause vehicles to consume more fuel and emit more greenhouse gases and CO and VOCs. We do not consider these types of effects either.

2.0 LITERATURE REVIEW

There have been very few detailed comparisons of emissions from transportation modes. However, there is a substantial body of literature on the energy use of different transportation modes. Because in most cases emissions are a function of energy use, this energy literature is relevant to our analysis. To our knowledge, though, none of the existing studies of emissions or energy use cover the range of modes, pollutants, emissions sources, and other factors considered here. The following are brief summaries of some of the more prominent studies. This review is by no means comprehensive; in particular, there are many more analyses of the energy use of different transportation systems[1].

• *Scheel (1972).* This early report estimates emissions of CO, HCs, NO_2, and SO_2 from automobiles, transit buses, commuter trains, and rail transit. The analysis does not include other pollutants, and does not include emissions from the use of energy for stations, maintenance activities, guideway or vehicle construction, emissions from upstream fuel processing, or emissions from modes of access to transit. Although the emission and energy-use factors are out of date, some of the conclusions are directionally similar to ours.

• *Fels (1975).* An original and detailed analysis of energy required to build guideways for rail systems.

• *Curry (1976).* This study summarizes an analysis of the energy consumption and air pollution impacts of eight case studies of new or improved transit services, including new bus lines, improved bus services, new exclusive bus corridors on the

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[1]For example, we expect that most environmental-impact analyses of new transportation projects include an analysis of energy-use impacts, if not emissions impacts. We have included only environmental impact analysis here (Westec Services, 1983).

Shirley Highway and on the San Bernadino Freeway, and new rail transit service in the Philadelphia-Lindenwold corridor. It appears to be the first study to have examined a broad range of factors that affect energy use and emissions. The study considered emissions from modes of access to transit, with a an explicit treatment of cold-start emissions, and estimated the impact of new transit modes on travel by other modes (i.e., distinguished former car drivers from former bus riders from new trip makers). It also presented estimates of "indirect" energy use and emissions -- from stations, maintenance activities, construction of vehicles and guideways, and upstream processing of fuel -- but did not include indirect energy and emissions in the model or final results.

• *Congressional Budget Office (1977).* This landmark study reviews theoretical and applied studies of transportation energy use, and estimates energy intensiveness, line-haul energy, modal energy, and program energy for single-occupant automobiles, average automobiles, carpools, vanpools, dial-a-ride, old heavy-rail transit, new heavy-rail transit, commuter rail, light-rail transit, and bus systems. "Energy intensiveness" is defined as propulsion energy per vehicle mile divided by the average number of occupants. "Line-haul" energy includes, in addition, the energy used by stations, maintenance activities and vehicle and guideway manufacturing. "Modal" energy is equal to line haul energy plus energy use by access modes, with accounting for the circuity of the total trip compared to an auto trip and the fraction of the trip that is devoted to access. Finally, "program" energy accounts for the overall modal split as a result of new or improved transit services. The study has been cited and debated widely, and remains the most comprehensive review of energy use by urban transportation modes.

The results of this study also are presented in Cohen (1978) and Kulash (1982). The written testimony submitted at the Senate hearing on this report contain excellent critiques of data, method, and interpretation of results (U.S. Senate, 1977).

• *Fels (1978)* . An original and detailed analysis of the operational energy requirements of the heavy rail systems in San Francisco (BART), Philadelphia (PATCO), and New York-New Jersey (PATH). The analysis includes energy used for propulsion, auxiliary and standby systems, station operation, and maintenance. Monthly utility bills for each system were the main source of data. Fels (1978) does not include "upstream" energy from production of fuels and electricity, and does not examine modes of access to transit. In an earlier paper, Fels (1975) estimated the energy requirements of making vehicles and guideways.

• *Cohen et al. (1978).* This study summarizes methods for estimating emissions from motor vehicles and energy use of urban transportation systems. With one exception, all of the data on energy use are from the CBO study (discussed above). The exception is a table of vehicle manufacturing energy and related data, from a 1976 FHWA report.

• *McCoy (1982).* McCoy summarizes data on seats per vehicle, average load, miles per gallon, and kWh per vehicle mile, for different sizes of passenger cars and buses, trolley coaches, light-rail systems in several cities, and old and new heavy rail systems in several cities. The data come from a variety of papers and reports (including Fels [1978] and the CBO [1977]) and personal communications in the 1970s. He does not present data on the energy use of stations, maintenance activities, guideway or vehicle construction, upstream fuel processing, or modes of access to transit.

• *Westec Services, Inc. (1983).* This draft Environmental Impact Statement (EIS) and Environmental Impact Report (EIR) compared the total system energy consumption of the then-proposed Los Angeles Metro Rail with the total consumption of the bus-and-car systems that it replaces. Westec used the Congressional Budget Office (1977) estimates of the amount of energy required to build and maintain cars and trucks and to build rail vehicles, and Southern California Regional Transit District (SCRTD) estimates of the amount of energy required to run and maintain the proposed Metro Rail. Guideway-construction and vehicle-manufacturing energy was annualized over an assumed 50-year life. SCRTD did estimate how much the rail system would reduce travel in automobiles and buses, but it is not clear if their estimate accounted for auto-access to the rail system.

The EIS and EIR for other rail projects have similar energy estimates.

• *Reno and Bixby (1985).* This handbook, used by transportation planners to estimate the performance of urban transportation modes, presents estimates of speed, capacity, operating costs, labor inputs, energy consumption, pollution, capital costs, and accident frequency of rail rapid transit, light rail, bus, auto, automated guideway, and pedestrian assistance systems. The report estimates emissions of CO, HCs, NO_X, SO_X, aldehydes, and PM from the generation of electricity for propulsion of rapid rail, light-rail, and commuter-rail systems. It also cites estimates of the energy requirements of stations, maintenance activities, vehicle manufacture, and guideway construction, but does not calculate the corresponding emissions. It also not include greenhouse gases or toxic air pollutants, or emissions from modes of access to transit.

• *Anderson (1988)* .Anderson derives a “transit energy equation,” which includes terms for rolling resistance, aerodynamic drag, acceleration, and auxiliary energy. He summarizes baseline input data for the key variables in the equation, and then uses the equation and the input data to calculate the energy requirements of heavy rail, light rail, trolley bus, motor bus, vanpool, dial-a-ride, automobile, and personal rail modes. He does not include data on the energy use of stations, maintenance activities, guideway or vehicle construction, upstream fuel processing, or modes of access to transit. His energy use equation is conceptually similar to the one we use to calculate energy use of motor vehicles.

• *Charles River Associates (1988).* This report presents statistics on a wide variety of aspects of urban transportation demand: socioeconomic characteristics of urban areas, trip generation, trip length, mode choice and auto occupancies, temporal travel distribution, truck travel, CBD characteristics, transit usage, and highway and HOV usage. The data on transit usage include summaries of modes of access to rail transit systems in several cities.

• *Linster (1990) and Lamure (1990).* These are chapters in *Transport Policy and the Environment*, published in 1990 the European Conference of Ministers of Transport.

Linster (1990) shows a matrix of environmental impacts and transportation modes in which the air-pollution / rail-transport cell is blank, but the air-pollution / road-transport cell is not, indicating that road transport but not rail transport causes air pollution. No explanation is given. Lamure (1990) provides a largely qualitative comparison of the air-pollution, energy-use, noise, and land-use impacts of rail versus road transport. He argues that "if the primary energy source is not coal or oil, then the benefits of using the railways are very considerable as regards pollution of all types" (p. 123). In support of this statement, he cites a Swedish study.

• *Hughes (1991).* Hughes reports the primary propulsion energy requirements (mJ / passenger-km) of bicycles, motorcycles, minibuses, double-decker buses, urban light rail, suburban rail, intercity rail, airplanes, diesel cars, and gasoline cars in Great Britain, for typical and maximum passenger loads. The analysis does not include the energy requirements of stations, maintenance activities, or guideway or vehicle construction, but it does account crudely for "upstream" energy used to process the end-use fuels and electricity. It does not consider modes of access to transit systems.

• *American Public Transit Association (APTA) (1991).* APTA estimates emissions of hydrocarbons, nitrogen oxides, and carbon monoxide, per passenger mile of travel, for rail transit, bus transit, vanpools, carpools, and single-person automobiles. The data are presented in the *Transit Fact Book,* an annual publication of the APTA. The analysis does not include other pollutants, and does not include emissions from the use of energy for stations, maintenance activities, guideway or vehicle construction, emissions from upstream fuel processing, or emissions from modes of access to transit. (APTA, personal communication, 1993). The underlying data are average factors for energy use, travel, and emissions in the U.S. in 1987-1988 (APTA, personal communication, 1993).

• *Blevins and Gibson (1991).* This paper compares energy use and emissions of freight trucks and trains in Canada. The authors examine four routes (where the two modes actually compete), three types of rail operation (trailer-on-flatcar, car-on-flatcar, carload), three time periods (1985, 1990, 1995), and a range of different truck and rail equipment. They estimate direct emissions of CO_2, NO_x, VOCs, CO, and PM. Emissions from trains are estimated on the basis of emission-test data; emissions from trucks are assumed to be equal to the pertinent emissions standards. CO_2 emissions are calculated on the basis of fuel use and carbon content. They do not consider SO_x, toxic pollutants, other greenhouse gases, or upstream emissions. They find that trains use 65 to 70% less fuel, emit 65 to70% less CO_2 and 30 to 50% less NO_x than do trucks.

• *Craig et al. (1991).* This report for the California Energy Commission estimates fuelcycle energy use (BTU / vehicle mile and BTU / passenger mile) and CO_2 emissions (per vehicle mile and per passenger mile) of motor buses, heavy rail, light-rail, commuter rail, trolley buses, ferry boats, vanpools, and cable cars. The data on energy use by transit systems are from the American Public Transit Association. The analysis does not include other greenhouse gases or any criteria or toxic-air pollutants, and does not include CO_2 emissions from the use of energy for stations, maintenance activities, guideway or vehicle construction, or modes of access to transit. It does, however, incorporate a detailed and original calculation of CO_2 emissions from the upstream processing of the end-use energy used for line haul.

• *Public Transport International (1991)*. This summary of report by the Canadian Urban Transit Association assumes that shifting car drivers to transit results in a net savings of the tailpipe emissions of CO_2, NO_X, VOCs, and CO from the eliminated vehicle trips. They do not count emissions from the buses or trains themselves, or from upstream processes associated with any system, or from the modes of access to the transit stations.

• *Feber and Vyas (1992)*. The authors calculate emissions of CO, HCs, NO_X, SO_X, and CO_2 from three intercity transport options: magnetically levitated intercity trains, airplanes, and automobiles. They use a utility simulation model to calculate emissions from power plants that would supply power to maglev trains, and they use MOBILE 4.1 to calculate exhaust, evaporative, refueling, and running loss emissions from motor vehicles. Electricity consumption for the maglev systems is calculated as the sum of power required for acceleration, aerodynamic drag, electromagnetic drag, and auxiliaries. The study does not consider emissions from the use of energy for stations, maintenance activities, guideway or vehicle construction, or emissions from modes of access to transit, and does not consider upstream fuelcycle emissions, PM emissions, toxic air pollutants, or greenhouse gases other than CO_2.

• *Feitelson (1994)*. This is a qualitative discussion of the direct and indirect environmental benefits and costs of rail transport. Feitelson lists “less air pollution per unit traveled” and “energy saving” as direct environmental benefits, but does give estimates or references. Vibration, noise, visual intrusion, barriers, and community severance are listed as direct environmental costs. Feitelson does note that “direct environmental benefits of rail are dependent on its ability to divert users from more polluting transport modes” (p. 210), and discusses a qualitative “market segmentation approach” to determining competitiveness of rail transit. The indirect environmental effects are mainly those on land use. Feitelson concludes that “although rail transit may reduce emissions by concentrating peak congestion spatially and temporally along some radial corridors, it is unlikely to significantly reduce total vehicle miles driven...given current land-use trends” (p. 219).

• *Maggi (1994)*. Maggi (1994) asserts that the Linster (1990) and Lamure (1990) studies cited above “illustrate the well known fact that road traffic [in Europe] is environmentally more harmful than rail traffic...most significantly [in the case of] air pollution” (p. 346; bracketed phrases are mine). He does not offer any other evidence in support of the assertion that the environmental superiority of rail is a “well known fact”.

• *Gwilliam and Geerlings (1994)*. These authors cite a 1992 study by the Commission of European Communities (CEC) that indicates that switching people from motor vehicles to other modes will reduce local air pollution, at least in the short term. I have not consulted the original CEC study.

• *LaBelle and Stuart (1995)*. Labelle and Stuart (1995) estimated the air quality “implications” of diverting drivers onto Chicago’s rapid-rail “Orange” line in 1994.

They estimated the amount of VMT and cold starts avoided as a result of shifting riders out of cars, and the amount added as a result of Park-and-Ride access to the rail line. They did not calculate changes in emissions, or consider emissions from the rail system itself. (In Chicago, most electricity comes from nuclear power.)

• *Kolb and Wacker (1995).* These researchers estimated energy use, and emissions of CO_2, by trucks, trains, ships, and planes carrying freight in Germany. They considered specific hauling tasks and routes, and estimated line-haul energy requirements in detail. They included energy use and emissions from loading and unloading operations, from "access" trips in the case of bi-modal systems, and from the construction, maintenance and disposal of vehicles, and the construction and maintenance of infrastructure. They concluded that "it is not possible to make general recommendations for transport modes" (p. 287), and that analyses should be done case by case.

Kolb and Wacker (1995) also report the results of a "similar" study done for passenger transport. They conclude that "in most cases," public transit had lower energy consumption and CO_2 emissions than did automobiles, but that the results depended greatly on the occupancy of the transit vehicles and the automobiles. If their analysis of the energy use and CO_2 emissions by passenger transport truly is similar to their analysis of freight transport (they do not report details of their analysis of passenger transport), then they probably include in the passenger-transport analysis emissions from access to public transit, and from the construction and maintenance of vehicles and infrastructure.

Apparently, neither the freight nor the passenger analysis considered emissions of other greenhouse gases, urban air pollutants, or toxics, or emissions from the lifecycle of fuels or electricity.

• *Barth et al. (1996).* Barth et al. (1996) compared emissions of VOCs, CO, NO_X, and PM from a commute via the Metrolink rail system in Los Angeles with emissions from a door-to-door commute via automobile. In the analysis of the rail commute, the researchers estimated emissions from the access trip from home to rail station, and emissions from the diesel locomotive line-haul from Riverside to Los Angeles. The surveyed passengers on the train in order to determine the mode and length of access to the rail station. They used the EMFAC7F model to estimate emissions from automobiles used in the access trip and the door-to-door commute. Also, they used remote sensing to determine the fraction of high-emitters, which is an input to the EMFAC model.

Barth et al. (1996) found that the rail-based commute produced less VOCs and CO but more NO_X and PM than did an auto-only commute.

The study did not consider toxic air pollutants, greenhouse gases, energy use, or emissions from upstream fuelcycle processes or maintenance activities.

See Barth and Tadi (1996) for a comparison of emissions from freight haul by rail with emissions from freight haul by truck.

3.0 ENERGY USE

3.1 Energy use by light-duty cars and trucks

Emissions of greenhouse gases and upstream emissions of criteria pollutants -- but not vehicular tailpipe emissions -- are a function of fuel consumption per mile. Vehicular tailpipe emissions are not a function of fuel use because the emissions standards are in units of grams / mile, not grams per gallon or energy unit[2].

The fuel consumption of a motor vehicle is a function of a number of characteristics of the vehicle and the trip: the size of the engine, the weight of the vehicle, the aerodynamic drag of the vehicle, the average speed of the trip, the number of stops and starts, the amount of time spent idling, and so on. Ross and An (1993) (see also An and Ross, 1993, and Ross, 1994) have developed a model to estimate the fuel economy of motor vehicles as a function of the key vehicle and trip parameters. Their model allows us to estimate the difference in fuel economy (and hence greenhouse-gas emissions and upstream emissions) between, say, a 10-mile trip on the freeways and a shorter access trip on surface streets to a transit station. It also allows us to estimate more subtle but nevertheless important effects: for example, the effect of an extra stop to pick up an extra passenger, and of the extra passenger's weight, on fuel economy. Table 1 shows our use of their model, for the base-case vehicle fuels and types shown in Table 44.

The original model (Ross, 1994; Ross and An, 1993; An and Ross, 1993) was specified only for gasoline vehicles. We have expanded it to calculate the fuel consumption of methanol, ethanol, CNG, LPG, and electric vehicles. The fuel consumption of alternative-fuel vehicles is calculated relative to that of gasoline vehicles: the fuel consumption of the gasoline vehicle is multiplied first by a factor that accounts for the thermal efficiency of the alternative-fuel engine relative to that of the gasoline engine, and then by a factor that accounts for any extra weight on the alternative-fuel vehicle due to fuel storage equipment (e.g., cylinders for compressed natural gas). We also have added a regenerative braking factor, used in the case of electric vehicles. The parameters for alternative-fuel vehicles are shown in Table 2.

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[2]Actually, there are two separate questions here: whether there is a relationship between fuel economy and emissions across different vehicles (the "design" relationship), and whether there is a relationship between fuel economy and emissions for any particular vehicle (the "use" relationship). That the emission standard is in grams / mile means that there probably is not a design relationship between fuel economy and emissions, because all vehicles must meet the same g / mile standard, regardless of fuel economy. However, the fuel economy of any individual vehicle can vary for reasons (such as extra weight) that can cause the emissions per mile to vary as well. See DeLuchi et al. (1994) for further discussion.

3.2 Fuel use by buses

All emissions per passenger mile of bus travel are a function of fuel consumption per mile. This functional relationship holds for criteria pollutants as well as for greenhouse gases, and, unlike in the case of passenger vehicles, for emissions from vehicles as well as for upstream emissions. Emissions from heavy trucks and buses, unlike emissions from passenger cars and light trucks, are regulated per unit of fuel consumption (in grams per brake-horsepower-hour); hence, a vehicle that travels more miles per unit of fuel consumed will emit fewer pollutants per mile. By contrast, emissions from passenger vehicles are regulated per mile of travel.

We calculate fuel consumption per mile for diesel buses as a function of the fuel consumption of the empty bus, the number of passengers on board and the average weight of each passenger, and the relationship between fuel consumption and weight. These data are documented in Table 3. We back-calculated the fuel consumption of empty diesel buses using data on actual fuel consumption and passenger loads for buses in Sacramento, San Francisco, Los Angeles, San Diego, Boston, and Washington, D. C.

The fuel consumption of alternative-fuel buses is calculated relative to that of diesel-fuel buses: the fuel consumption of the diesel-fuel bus is multiplied first by a factor that accounts for the thermal efficiency of the alternative-fuel engine relative to that of the diesel-fuel engine, and then by a factor that accounts for any extra weight on the alternative-fuel bus due to fuel storage equipment (e.g., cylinders for compressed natural gas). The parameters for alternative-fuel vehicles are shown in Table 2.

Source of data. The Federal Transit Administration (FTA), formerly the Urban Mass Transit Administration (UMTA), collects data on the energy use, operating expenses, revenues, and performance of transit systems in the U.S. The data are reported by the transit operators themselves, and constitute the most extensive original data series for transit systems in the U.S. UMTA/FTA sent us their complete data tables (in a spreadsheet data base) of energy use, operating expenses, and transit performance for every transit system in the U.S. from 1983 to 1990. We combined, reorganized, and condensed the data to be able to calculate the average speed, load factor (the second-to-the-last column of Tables 6 to 4), energy use per passenger-mile, and energy use per passenger capacity-mile of buses and trains in Los Angeles, San Francisco, Sacramento, San Diego, Boston, and Washington, D. C. Tables 4 to 6 show the results of this exercise for the years 1988, 1989, and 1990.

3.3 Electricity use by electric trains

Emissions per passenger-mile of train travel are a function of electricity consumption per passenger-mile of train travel. In this analysis, we assume that the electricity consumption per passenger-mile is equal to the electricity use per capacity (or place)-mile of travel divided by the load factor. The electricity use per capacity-mile is a rough indicator of the technological efficiency of the system. The load factor is equal to actual passenger-miles of travel divided by passenger-capacity-miles of travel; the higher the load factor, the lower the electricity use per passenger-mile, because each additional rider on a train increases the weight by only a small fraction and therefore increases electricity consumption per vehicle-mile by only a small fraction. (In the case of trains, we ignore this weight effect of extra passengers, and assume that electricity use per vehicle-mile is independent of the load factor.) With these inputs, we calculate first the electricity use per passenger-mile, and then the emissions per passenger-mile.

Source of data. See “Sources of data” in section 3.2 above.

Marginal mix of fuels to generate electricity for trains. We assume that trains in Sacramento use the marginal power mix in Sacramento, that trains in San Francisco use the marginal power mix in San Francisco, and so on. Our estimation of the marginal power mix in each area is discussed below.

3.4 Energy use by power plants

Energy use by power plants is discussed in section 4.2, emissions from power plants

3.5 Energy use for non-traction purposes (for transit stations, administrative buildings, and maintenance of transit systems)

Rail and bus systems consume energy to heat and light administrative buildings, run maintenance facilities, power train stations and bus stops, and fuel non-revenue vehicles (mainly maintenance vehicles and administrative vehicles). We surveyed accountants and fleet managers for transit systems in Sacramento, San Francisco, Los Angeles, San Diego, Boston, and Washington, D. C., to find out the amount and kind of energy actually consumed in recent years for these nontraction purposes -- for everything other than the operation of revenue vehicles. (These energy-use factors, multiplied by emission factors per energy unit, yield estimates of emissions as a function of use, which is what we are interested in.) The results of our surveys are presented in Table 7.

As mentioned above, we wish determine the amount and kind of energy used by transit systems for everything other than the operation of revenue vehicles. This energy use, plus energy use by revenue vehicles, should be a complete and accurate account of all energy used directly by transit systems. To be sure, however, we compared our estimates with estimates from the literature. If our survey is comprehensive and accurate, our estimates of energy use should be comparable to, and perhaps greater than, the estimates in the literature. (We say “greater than” because some of the estimates in the literature do not cover *all* non-traction uses of energy, whereas our estimates are meant to.) In Table 2, our survey estimates are expressed relative to energy use by the transit vehicles themselves, and compared with estimates in the literature of station and maintenance energy use expressed in the same way. Our estimates non-traction energy use appear to be slightly higher than the estimates of station and maintenance energy that we found in the literature (e.g., compare our estimates of BART energy). As we explained above, this actually is a good finding, because it suggests that we have not omitted important sources of energy in our surveys. (Our estimates cannot be overestimates, because they are based on actual reported energy consumption.)

3.6 Energy use by fuel production facilities

Energy use by petroleum refineries is discussed in section 4.6, emissions of greenhouse gases, and section 4.3, emissions from fuel production. Energy use by methanol and ethanol production facilities is discussed in section 4.3, emissions from fuel production.

3.7 Energy use by motor-vehicle service industries, by the maintenance and operation of highway infrastructure, and by related activities.

In section 3.5, we estimate energy use by the stations, maintenance activities, and administrative functions of transit systems -- all transit-system energy use other than that by revenue vehicles. For a symmetrical comparison, we must estimate the same sort of non-vehicular energy use attributable to motor vehicles. This turns out to be difficult, because the motor-vehicle "system" is not contained in and managed by a single entity with comprehensive records, in the way that a transit system is. Many facilities and activities related to motor-vehicle use consume energy and thus emit pollutants: petroleum bulk plants, petroleum bulk terminals, gasoline service stations, motor-vehicle manufacturing plants, parts stores, motor-vehicle dealerships, motor-vehicle maintenance and repair shops, commercial parking lots and garages, home garages, vehicle renting and leasing services, highway maintenance and police operations, highway lighting, motor-vehicle insurance offices, and offices of public motor-vehicle departments[3]. These facilities and activities use electricity, natural gas, gasoline, and diesel fuel, for power and heating. Together, this energy use is comparable to the non-traction energy use of transit systems.

The few pertinent estimates of this energy use in the literature apparently are based on studies done in the early 1970s by Oak Ridge National Laboratory. The Congressional Budget Office (CBO) (1977) cites a 1977 study by BART that estimates that automobiles consume 1,634 BTUs / vehicle-mile for "maintenance and station energy", and a 1975 study by U.S. Office of Technology Assessment (OTA) that estimates that automobiles consume 4,930 BTUs / vehicle mile for maintenance and station energy, including energy associated with tolls, insurance, and parking. (On the basis of these studies, the CBO estimates that automobiles require 2,000 BTUs / vehicle mile for maintenance and station energy.) The BART study, and probably the OTA study, draw on a studies in the early 1970s by Hirst of Oak Ridge National Laboratory. Curry (1976) reproduces one of Hirst's studies. Hirst multiplies estimates of dollar-expenditures per vehicle mile of travel (VMT) by an "energy coefficient" of BTUs / $-expenditure (derived from a GNP / energy input-output analysis) to obtain an estimate of BTU / VMT. His results, as reported in Curry (1976), are:

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[3]We analyze emissions from petroleum refineries, and, on the transit side, emissions from electricity generation, separately. And in both the transit analysis and the motor-vehicle analysis, we do not count energy use and emissions of construction activities.

automobile manufacture	1,300
automobile transport	300
repairs, maintenance, parts	400
tires	200
insurance	400
parking, garaging, tolls	500
taxes (highway construction)	1,000

For two reasons, the Hirst BTU/$ estimates are not suitable for us. First, we have no idea how accurate they are. Generic BTU/$ coefficients might or might not be accurate for individual industries. Second, these coefficients probably include energy used for construction, which we do not count. Consequently, we have performed our own analysis of energy use by motor-vehicle maintenance, service, administration, parts, etc. (Although we do make some $/BTU extrapolations, our $/BTU coefficients do not include construction energy.)

We use data from the Bureau of the Census on actual expenditures for energy in the relevant motor-vehicle related industries (excluding vehicle manufacturing). For most of these industries, the U.S. Bureau of the Census reports expenditures on electricity and fuel, but not actual physical quantities consumed. We divide expenditure data by our estimate of price in order to estimate physical quantities (e.g., kWh or BTUs). The calculations are documented in Tables 9 and 10.

We have extrapolated from the raw Census data to account for several sources of energy use not included in the Census data. First, we extrapolated energy use in SIC 753, maintenance and repair, to account for the relatively minor amount of maintenance and repair work done "in house" by businesses. Second, we extrapolated energy use in SIC 55, motor vehicles and motor-vehicle parts, to account for small amount of sales in other industries (such as department stores) (we also deducted energy use attributable to non-motor-vehicle related sales within SIC 55 [e.g., food sales at gasoline stations]). Third, we extrapolated energy use in SIC 752, parking, to account for energy use by free parking lots and garages. Fourth, we estimated energy use by residential (non-commercial) parking spaces. Finally, we extrapolated energy use in SICs 752 and 754 to account for energy use by insurance companies, highway maintenance activities and lighting, and public motor-vehicle agencies. Our estimates and extrapolations are documented in the notes to Tables 9 and 10.

We emphasize that we do not have much confidence in either the extrapolation from SIC 752 to account for free parking, or the extrapolation from SICs 752 and 754 to account for insurance, highway maintenance, and so on (last in the list above). As explained in note i of Table 10, to account for energy use at free parking facilities, we simply multiply energy use in SIC 752 (paid parking) by 20, which we assume is the ratio of all parking (95% of which is free) to paid parking. The problem here is that the starting datum is a very small fraction of the extrapolated total. As we explain in note i, an alternative extrapolation produces a much, much higher result. The extrapolation of energy consumption in SICs 751 and 754, to account for the energy consumption of automobile insurance companies, highway maintenance and lighting, motor-vehicle departments, and police, fire, and justice department, is done on the basis of the ratio of expenditures in all of these areas to receipts in SICs 751 and 754 (note h of Table 10). This ratio is about five. Obviously, energy use might not correlate well with dollar expenditures or receipts.

Nevertheless, our "best" estimate of total energy consumption is less than 250 BTUs/VMT -- about a order of magnitude lower than Hirst's estimates. We believe that only a small part of this difference can be attributed to our exclusion of construction energy. Moreover, we are reasonably confident of our estimates of energy use by bulk plants, bulk terminals, service stations, parts stores, dealerships, repair facilities, and residential parking spaces. We conclude that either Hirst's estimates are too high, or that our estimate of energy used for commercial parking, and our extrapolation of energy use in SICs 751 and 754, are too low. For example, as indicated in the notes to Table 10, an alternative data set suggests that commercial parking consumes about 50 times (!) more energy than we have estimated. Clearly, more work in this area is needed.

As indicated in Table 10, we assume that all vehicles consume (indirectly) the same amount of energy, per mile, for maintenance, service, sales, and parking. We assume that all liquid-fuel service stations (including LPG stations) consume the same amount of energy per 10^6 BTU of fuel dispensed. However, we have calculated separately the energy requirements of stations that dispense natural gas, because of the large energy requirements of compression.

4.0 EMISSION FACTORS

4.1 Emission factors for motor vehicles

Motor-vehicles emit air pollutants from four distinct sources: combustion processes in the engine, the evaporation of fuel, the wear of tires and brakes, and the kicking up of road dust. Combustion emissions (generally referred to as tailpipe or exhaust emissions) are a function of the ambient temperature, the power output of the engine, the characteristics of emission-control systems, the characteristics of fuel, the ratio of air to fuel, and other factors. Combustion processes produce all of the pollutants and greenhouse gases considered in this analysis. Evaporative emissions are a function of the characteristics of the fuel, ambient temperature, the characteristics of emission-control systems, and other factors. Evaporative emissions consist of the lighter hydrocarbons in a fuel. Tire-wear, brake-wear, and road-dust emissions are particulate matter, and are a function of vehicle size and weight and other factors.

The California Air Resources Board (CARB) and the U.S. Environmental Protection Agency (EPA) have developed computer models to estimate exhaust (combustion) and evaporative emissions from motor vehicles. We use CARB's EFMAC emissions model and other data to estimate exhaust and evaporative emissions from conventional and alternative-fuel cars, vans, and buses. We use CARB and EPA emission factors and emission-factor equations and other data to estimate PM emissions from tire wear, brake wear, and road dust.

4.1.1 NMOG, CO, and NO_X exhaust emission factors for gasoline and diesel vehicles

Modern engines and emission-control systems take a few minutes to warm up, and during this warm-up vehicles emit considerably more carbon monoxide (CO) and hydrocarbons (HCs) per mile than they do when they are fully warmed up. As a result, emissions from motor vehicles are not simply proportional to distance: a trip of 3 miles produces much more than half of the CO and HC emissions of a trip of 6 miles. This is relevant to our analysis because access trips to transit by motor vehicle typically are much shorter than straight door-to-door commute trips by auto. Figure 1 shows an idealization of emissions as a function of trip distance over the Federal Test Procedure.

The California Air Resources Board (CARB) emission-factor calculation method (CARB, *Methodology for Estimating Emissions from On-Road Motor Vehicles, Volume 1: EMFAC7F*, , 1993), accounts for the phenomenon of higher "cold-start" emissions by assuming that at the beginning of a trip there is an "extra" or "incremental" emission relative to emissions from a fully warmed-up engine. These "incremental" emissions are added to emissions from a fully-warmed up engine, which are expressed in grams / mile, to obtain total emissions from a trip. CARB's emission-factor model, EMFAC, produces incremental cold-start, incremental hot-start, and running exhaust emission factors for gasoline vehicles (GVs) and diesel vehicles.

We use CARB's emission-factor model, and data from emissions tests, to develop a model of gram-per-mile emission factors as a function of trip distance. We use this model to estimate emissions from light-duty autos and light-duty trucks (i.e., vans) fueled with reformulated gasoline, and from diesel-fueled buses. Then, using data and methods explained below, we estimate emissions from alternative-fuel vehicles relative to the gasoline or diesel-fueled baseline.

Table 11 shows EMFAC-calculated emissions from gasoline cars and trucks and diesel buses in the year 2003, under the "standard" conditions (75^{o} F, 20 mph) of the Federal Test Procedure (FTP), which provides the raw data used in the EMFAC model. Of course, in any particular city, the actual temperature and average speed will be different from the FTP standards. The EMFAC model has equations which scale the emission factors up or down for temperature and speeds other than the standard ones. We use these temperature and speed "correction" equations in this analysis to estimate emission factors at any speed and temperature.

4.1.2 NMOG, CO, and NO_X exhaust emission factors for alternative-fuel vehicles.

CARB's EMFAC model does not calculate emission factors for alternative-fuel vehicles (AFVs). Consequently, we must develop our own set of equivalent factors for AFVs. We calculate the AFV factors from scratch, using data from the Federal Test Procedure (FTP). Specifically, we start with data on "modal" emissions (cold-transient, hot-transient, and hot-stabilized emissions) from AFVs over the FTP, and calculate emission factors for the AFVs *relative* to the modal factors for GVs, for the particular

FTP results. Then, we multiply these relative emissions factors by the absolute cold-start increment, hot-start increment, and stabilized running emission factors calculated from EMFAC. Formally:

$$Eam = Egm \infty (Eat / Egt) \infty Sc \infty Tc \quad (0)$$

where:

Eam = the calculated emission factor (incremental cold start [C}, incremental hot start [H], or stabilized running exhaust [S]) for the AFV, calculated with respect to the EMFAC model result for the GV

Egm = the EMFAC-model-calculated emission factor for the GV (Table 11)

(Eat / Egt) = the ratio of the AFV emission factor [C, H, or S] to the GV emission factor [C, H, S], from a set of FTP tests (derived below)

Sc = the relevant speed correction factor (correcting for the difference between EMFAC value of Table 11 [20 mph] and the city-specific values [e.g., Table 1].) (we assume that the correction factors for AFVs are the same as those for GVs)

Tc = the relevant temperature correction factor (correcting for the difference between EMFAC value of Table 11 [75^{o} F] and the city-specific values [e.g., Table 1].) (we assume that the correction factors for AFVs are the same as those for GVs)s

the subscripts “a” and “g” refer to AFVs and GVs, respectively

the subscripts “m” and “t” refer to EMFAC model results and FTP test results, respectively

We emphasize that this method calculates the ratio of AFV to GFV modal emission factors from a particular series of emissions tests done by the ARB (Purnell, 1995; Croes, 1995; see also CARB, 1992; McNair et al., 1994) and then multiplies these ratios by the absolute GV incremental and running emission factors from EMFAC. We use this method because it explicitly relates modal emissions from AFVs to modal emissions from GVs, which is desirable because in essence we wish to analyze the effect on emissions of variously “weighting” the three modes (cold-start, hot-start, stabilized) of the drive cycle.

Formally, our analysis proceeds as follows. Keep in mind that the objective is to express the desired quantities -- the (Eat / Egt) ratios above -- in terms of the known quantities: the bag emissions from AFVs and GVs We start with the equation for calculating total FTP emissions from a gasoline vehicle:

$$0.43B1g + 0.57B3g + B2g=Fg \quad (1)$$

where:

B1g = bag-1 (cold transient) emissions from a gasoline vehicle (in Figure 1, the total area under the curve from 0 to B1)
B3g = bag-3 (hot transient) emissions from a gasoline vehicle (in Figure 1, the total area under the curve from B2 to B3)
B2g = bag-2 (hot stabilized) emissions from a gasoline vehicle (in Figure 1, the total area under the curve from B1 to B2)
Fg = total grams emitted from a gasoline vehicle during the FTP test

Now, the incremental cold-start emission is defined as the amount of emissions in bag-1 (cold transient) *in excess* of the emissions that a fully warmed up engine would have emitted during the bag-1 test (CARB, *Methodology for Estimating Emissions from On-Road Motor Vehicles, Volume 1: EMFAC7F*, , 1993; Horowitz, 1982). The emissions from a fully-warmed up engine are a function of average speed. In the FTP, bag-2 emissions (hot stabilized) divided by the distance in miles of the bag-2 test yields g / mi emissions from a fully-warmed up engine at the bag-2 speed of 16 mph. However, the bag-1 test has a higher average speed, 25.6 mph. The g / mi factor calculated from the bag-2 factor at 16 mph must be "corrected" to 25.6 mph, by use of a speed correction factor, before it can be applied to the bag-1 data for the purpose of calculating the cold-start increment. Hence, the amount that a fully warmed up engine would have emitted during the bag-1 test cycle is equal to the bag-2 g / mi factor, multiplied by the speed correction factor, multiplied by the distance of the bag-1 test in miles. Formally, then, the incremental cold-start emission is calculated as:

$$Cg = B1g - B2g \infty S2 \infty D1 / D2 \qquad (2a)$$

where:

Cg = the incremental cold-start emission from gasoline vehicles (in grams; area C1 + C2 of Figure 1)
B1g, B2g are as defined above
S2 = the speed correction factor (emissions at the bag-2 speed adjusted to what emissions would have been at the bag-1 speed)
D1= the distance of the bag-1 test (3.6 miles)
D2 = the distance of the bag-2 test (3.9 miles)

Similarly:

$$Hg = B3g - B2g \infty S2 \infty D1 / D2 \qquad (2b)$$

and

$$Sg = B2g \infty S2 / D2 \quad \text{(in Figure 1, } B2g / D2 = Sg'; Sg = Sg' \infty S2) \qquad (2c)$$

where:

Hg = the incremental hot-start emission from gasoline vehicles (in grams; area H1 of Figure 1)
Sg = the stabilized running exhaust-emission factor for gasoline vehicles (grams / mile)

The analogous expressions for AFVs are:

$$Ca = B1a - B2a \infty S2 \infty D1 / D2 \qquad (2d)$$
$$Ha = B3a - B2a \infty S2 \infty D1 / D2 \qquad (2e)$$
$$Sa = B2a \infty S2 / D2 \qquad (2f)$$

Thus:

$$\mathbf{Ca/Cg = (B1a - B2a \infty S2 \infty D1/D2)/(B1g - B2g \infty S2 \infty D1/D2)} \qquad \mathbf{(3)}$$

$$\mathbf{Ha/Hg = (B3a - B2a \infty S2 \infty D1/D2)/(B3g - B2g \infty S2 \infty D1/D2)} \qquad \mathbf{(4)}$$

$$\mathbf{Sa/Sg = B2a/B2g} \qquad \mathbf{(5)}$$

We use equations (3) - (5) to scale EMFAC-calculated modal emission factors for gasoline vehicles[4].

Finally, note that we calculate the bag emissions (B1a, B1g, B2a, B2g, etc.) from two sets of input data: i) the *distribution* of emissions among the three bags, for each pollutant and fuel type; and ii) overall FTP emissions from AFVs *relative* to overall FTP emissions from GVs. CARB provided emissions profiles by bag for AFVs (Croes, 1995; Purnell, 1995; see also McNair et al., 1994, and CARB, 1992), which we used to calculate distribution by bag[5]. Our assumptions regarding overall FTP emissions from AFVs relative to overall FTP from GVs are shown in Table 12.[6] The calculation is shown below.

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[4] The cold-start or the hot-start increment will be negative if the gram / mile emission rate in the FTP bag-1 cold-transient mode or the FTP bag-3 hot-transient mode actually is less than the gram / mile rate in the FTP bag-2 stabilized mode. A negative increment is odd but not necessary physically impossible: it implies that a vehicle emits less per mile when it is cold than when it is warmed up. We leave negative increments negative, because an increment set equal to zero (when calculated to be less than zero) will not faithfully reproduce the original FTP results from which it was derived.

[5] For ethanol there were only 8 tests on 2 vehicles -- far fewer vehicles and tests than for the other fuels (Croes,1 995). Consequently, the factors for ethanol are relatively uncertain.

[6] One might ask why we do not calculate AFV emission factors directly from the AFV-FTP bag emissions data (and other test data), in the way that we calculate GV emission factors from FTP test data and other data. There are two reasons. First, we do not have enough AFV emissions data to develop emission factors of the same robustness as those calculated in EMFAC for GVs. Certainly, we cannot develop speed correction factors, temperature correction factors, and so on, for AFVs. Second, AFV emission factors depend greatly on the engine design, emission-control technology, and fuel quality, all of which still are

Define the sum of bag emissions, and the bag distribution factors:

$B1g + B2g + B3g = Tg$

and

$B1g / Tg = B1g'$ (distribution factor for bag 1)
$B2g / Tg = B2g'$ (distribution factor for bag 2)
$B3g / Tg = B3g'$ (distribution factor for bag 3)

Thus we have:

$$B1g = B1g' \infty Tg \tag{6a}$$
$$B2g = B2g' \infty Tg \tag{6b}$$
$$B3g = B3g' \infty Tg \tag{6c}$$

That is, we will calculate bag emissions given the distribution of emissions by bag, and a calculated value of Tg, total FTP emissions from the GV. The equations for AFVs are analogous. To calculate Tg:

Divide equation (1) by Tg on both sides:

$0.43B1g / Tg + 0.57B3g / Tg + B2g / Tg = Fg / Tg$
$0.43B1g' + 0.57B3g' + B2g' = Fg / Tg$
$$Tg = Fg / (0.43B1g' + 0.57B3g' + B2g') \tag{7}$$

The equation for AFVs is:

$$Ta = (Fg' \infty R) / (0.43B1g' + 0.57B3g' + B2g') \tag{8}$$

where:

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evolving. There are not enough data to develop a different set of emission factors for each of a variety of engine / control / fuel combinations, and even if there were, it would be cumbersome to use many sets of emission factors. Instead, it is simpler and probably more accurate (given the present data) to express AFV emission factors relative to GFV emission factors, and to manipulate a simple, easily obtained parameter -- the ratio of total AFV-FTP emissions to total GV-FTP emissions -- to represent the effect of different engine / control / fuel combinations. In fact, even if there were enough AFV emissions data to develop separate AFV emission factors, it still might be better to model AFV emissions *relative* to GV emissions, to ensure that the treatment of AFVs was consistent with the treatment of GVs.

One also might ask why we calculate bag emissions from data on emissions distribution by bag and overall FTP emission ratios, rather than simply use the available bag emissions data directly. We do this because it allows us to use the ratio of AFV to GV FTP-emissions -- a widely used and easily obtainable metric -- as an input variable, and allows us to manipulate the bag-distribution of the emissions separately from the total amount.

$$Fa / Fg = R$$

Note that when we take the ratios of Ca to Cg, Ha to Hg, and Sa to Sg, in equations (3) to (5), all of the Fg will cancel out. Thus, we do not need to know Fg, We need to know only the bag distribution factors (B1g', B2g', etc.) and the ratio of AFV-FTP emissions to GV-FTP emissions (R; Table 12).

4.1.3 Adjustment for very short trips

As noted above, in the EMFAC model the start increments (Cg or Hg) are added to stabilized running emissions (Sg) to produce total emissions over a trip. If the start increment -- the "extra" emissions with respect to stabilized running emissions -- always occurred instantaneously at the beginning of a trip, then total emissions always would be equal to stabilized emissions plus the start increment, regardless of trip length. But of course, the start increment is not instantaneous; it is "spread out" over the distance that it takes the engine and catalyst to fully warm up, which probably is on the order of 1 to 3 miles (Horowitz, 1982). A very short trip that ends before the engine is fully warmed up will not have emitted the full "incremental" start emission.

This is illustrated in Figure 1, where a trip ends at distance X, before the cold-start increment has ended (at distance W). For the trip of distance X, total emissions are equal to $Sg \infty X + C1$. However, the cold start increment is equal to C1+C2 (equation (2a)), and thus EMFAC-calculated emissions would be equal to $Sg \infty X + C1 + C2$ -- too high by the amount C2, which never actually is emitted.

In our model, we account for this by reducing the cold start increment to the area C1 whenever the trip distance X is less than W, which we assume is 2 miles. (We do the same for hot starts, which we assume last for 1 mile.) Formally (for cold starts):

$C1 + C2 = Cg$ (from Figure 1 and equation 2a)

$$C1 = Cg - C2$$

Because C2 and Cg are similar triangles:

$$C2 / Cg = ((W - X) / W)^2$$

$$C2 = Cg\ ((W - X) / W)^2$$

$$C1 = Cg - Cg\ ((W - X) / W)^2$$

Now, let:

$$X / W = K$$

So that we have:

$$C1 = Cg - Cg\ (1-K)^2 =$$

$Cg\ (1 - (1 - K)^2) =$
$Cg\ (1-(1-2K+K^2)) =$
$Cg\ (2K-K^2)$

We use the factor $2K-K^2$ to adjust the cold-start or hot-start increment whenever the trip distance X is less than warm-up distance W. We also have introduced an additional constraint: if the start increment is negative, the Y intercept (Yc in Figure 1) cannot be less than zero.

4.1.4 NMOG emissions adjusted for ozone reactivity

Although NMOG emissions can be harmful in themselves, they are more deleterious as precursors to ozone formation. Different NMOG species contribute to ozone formation at different rates (Carter, 1994). The composition of NMOG emissions, and hence the ozone forming potential of NMOG emissions, varies widely among the alternative fuels. For example, ethane emissions from CNG vehicles are relatively unreactive, whereas as formaldehyde emissions from methanol vehicles are relatively reactive. To account for this differing contribution to ozone formation, the individual NMOG emissions species can be weighted by their ozone reactivity, *relative* to the overall ozone-forming potential of the mix of NMOG emissions from the baseline gasoline vehicle. We do this here.

Specifically, we estimate CE, HE, and SE for reactivity-weighted NMOG emissions, as well as for straight mass NMOG emissions. The calculation of reactivity-weighted emission factors is identical to the calculation of NMOG mass emission factors, except that we use reactivity-weighted emissions in place of straight mass emissions. Relative reactivity adjustment factors are from Carter (1994) and McNair et al. (1994)[7]. Note that reactivity-weighted NMOG emissions from the AFVs are less than straight mass NMOG emissions, because on the whole, the constituents of AFV exhaust (and especially of CNG exhaust) are less reactive than are the constituents of GV exhaust.

4.1.5 Emission factors for exhaust emissions of other pollutants

CARB's EMFAC model produces estimates of PM exhaust emissions (Table 11). These emission factors are constant for all speeds and temperatures. We use them here. We use DeLuchi's (1991) estimates of emissions of the greenhouse gases CH_4 and N_2O from GVs and buses. Our assumptions for AFVs (relative to the assumptions for GVs and buses) are shown in Table 12. We estimate emissions of toxic air pollutants as a fraction of NMOG emissions, for all vehicle types (Table 13).

4.1.6 Evaporative emissions.

[7]We assume that the bag-by-bag distribution of reactivity-weighted emissions is the same as the as distribution of unweighted emissions.

CARB's EMFAC model calculates four kinds of evaporative emissions: i) diurnal emissions, caused by daily temperature fluctuations; ii) hot-soak emissions, which occur just after a vehicle is turned off; iii) running loss emissions from the fuel lines and tank while the vehicle is running; and iv) resting-loss emissions from the fuel lines and tank while the vehicle is resting. We "correct" EMFAC values to the particular average daily high and low temperatures in the cities that we are analyzing. Note, though, that in the base case we do not count resting losses or diurnal losses, because these emissions do not depend on the *use* of the vehicle -- they occur when the vehicle is sitting around.

Total hot-soak evaporative emissions are a function of the number of hot-starts. For vanpools and carpools, we estimate the number of hot starts as a function of the number passengers, assuming that the vehicle idles during half of the passenger pick-ups, and is turned off and restarted for the other half.

The EMFAC-estimated evaporative emissions are shown in Table 11.

4.1.7 Emission factors for buses

The emission factors for buses are derived from the results of dynamometer tests, in which bus engines are run over a standard bus driving cycle, which includes idling. However, because diesel buses do not have catalytic converters, they do not have large incremental cold-start or hot-start emissions. Also, diesel fuel has a very low standard vapor pressure, and as result diesel buses have relatively minor evaporative emissions. CARB's EMFAC emissions model assumes that incremental cold-start, incremental hot-start emission, and evaporative-emissions from diesel buses are zero. We follow suit, and estimate running exhaust emissions only, as a function of average speed.

Alternative-fuel spark-ignition buses with catalytic converters probably do have incremental cold-start and hot-start emissions. However, many alternative-fuel buses do not have catalytic converters, and in any event it is not particularly important to model cold-start and hot-start emissions from buses because there is little reason to systematically vary trip distances by buses. We do not estimate incremental hot-start or cold-start emissions from alternative-fuel buses. Also, because we do not estimate incremental hot-start or cold-start emissions from buses, whether diesel or alternative-fuel, we do not need to estimate the number of stops and starts.

Methanol and ethanol buses will have some evaporative emissions. We estimate these emissions as a function of the amount of fuel use by buses per mile relative to fuel use by passenger cars per mile.

CARB's EMFAC model and the EPA's MOBILE model estimate emissions from buses in units of grams / mile. However, the emission standards for buses (for all HDVs, actually) are in units of grams per brake-horse-power-hour (g / bhp-hr), not grams / mile. Presumably, then, all buses are designed to meet to meet a g / bhp-hr standard. This matters because if all buses meet a given g / bhp-hr standard, then buses that have a brake fuel use (bhp-hrs / mi) different from that of the buses whose emissions constitute the EMFAC database will have different g / mi emissions. For example, buses that are more efficient than the ones used to make the EMFAC model -- that is, buses that use fewer bhp-hrs per mile -- will emit fewer grams of pollution per mile. Formally, g / mi emissions from any particular bus are equal to g / mi emissions from EMFAC buses scaled by the ratio of the brake-fuel use of the particular bus to the brake fuel use of the EMFAC buses:

$$[g/mi]_t = [g/mi]_e \times \frac{[b/mi]_t}{[b/mi]_e}$$

where:

g / mi = grams of pollutants emitted per mile of bus travel
b / mi = brake horsepower-hours of engine work used per mile of bus travel
the subscript “t” refers to buses in this analysis
the subscript “e” refers to buses used in the EMFAC model data base

We do not know the ratio of the b / mi terms per se. However, we do know, or can guess, the ratio of the fuel economies and the ratio of the thermal efficiencies. Therefore, we expand the b / mi terms:

$$[b/mi] = [f/mi] \times [b/f]$$

where:

f / mi = fuel use per mile, in horsepower-hours of fuel per mile (in effect, the inverse of fuel economy)
b / f = the thermal efficiency of the engine (brake hp-hrs of engine work per hp-hr of fuel supplied to the engine)

And we end up with:

$$[g/mi]_t = [g/mi]_e \times \frac{[f/mi]_t}{[f/mi]_e} \times \frac{[b/f]_t}{[b/f]_e}$$

We assume that the thermal efficiency of the bus engines in this analysis is close to the thermal efficiency of the bus engines in the EMFAC data base, and hence that $[b/f]_t / [b/f]_e$ is approximately equal to 1.0. The $[f/mi]_t$ are calculated using the data of Tables 2 and 3. Thus, the only problematic unknown in this equation is the fuel use, $[f/mi]_e$, of the buses used in the EMFAC database. We assume 3 mpg on diesel fuel, or about 46,200 BTUs of diesel fuel per mile.

4.1.8 Final aggregate exhaust and evaporative emissions factors

Given incremental and running exhaust emissions, and evaporative emissions, corrected for speed and temperature differences, the final total trip-average g / mile emissions factors are equal to:

$$(C \infty Fc + H \infty Fh + Hs \infty Fh) / Dt + R + Rl + (Re + Di) / (Td \infty Dt)$$

where:

C = the cold-start exhaust-emission increment, “corrected” for speed, temperature, and distance (g / cold- start)
Fc = cold-start trips divided by total trips
H = the hot-start exhaust-emission increment, “corrected for speed, temperature, and distance (g / hot start)
Fh = hot-start trips divided by total trips
Hs = evaporative hot-start emissions (g / hot start)
Dt = the distance per trip
R = corrected running exhaust emissions (g / mi)
Rl = temperature-corrected running-loss evaporative emissions (g / mi)
Re = temperature-corrected resting-loss evaporative emissions (g / day)
Di = temperature-corrected diurnal evaporative emissions (g / day)
Td = trips per day

The final corrected emission factors used in this analysis for Sacramento are shown in Table 14. The final emission factors for the other cities were derived identically, and are very similar to those shown for Sacramento. (Note that in our base-case estimates, we do not include diurnal evaporative emissions or resting loss emissions, because these emissions are not a function of vehicle use -- they occur when the vehicle is not being used.)

4.1.9 Emissions of PM_{10} from tire wear, brake wear, and re-entrained road dust.

A substantial fraction of the particulate matter suspended in the atmosphere consists of particles from motor-vehicle tires and brakes, and dust and other material that motor vehicles kick up from roads. In fact, road dust alone is by far and away the largest source of small-diameter particulate matter (of 10 microns or less diameter; PM_{10}) in the U.S., accounting for over 40% of all anthropogenic *and* biogenic PM_{10} emissions in 1994 (EPA, *National Air Pollutant Emission Trends, 1900-1994,* 1995). Because road dust is such a large source of PM_{10}, and PM_{10} probably is the most harmful major air pollutant (McCubbin and Delucchi, 1995), it is important to accurately model PM_{10} emissions attributable to motor vehicles.

Tire wear and brake wear. CARB’s EMFAC7F model estimates that in the year 2003, light-duty vehicles will emit 0.2 g / mi PM from tire wear, and buses 0.66 g / mi. The EPA estimates that light-duty vehicles emit 0.002 g / mi from tire wear, and 0.0128 g / mi from brake wear (Sha et al., 1983; Energy and Environmental Analysis, 1985). (CARB does not estimate emissions from brake wear; EPA does not estimate factors for heavy-duty vehicles.) These two estimates of tire-wear emissions differ by two orders of magnitude! In the absence of better data, we use the CARB factors for tire wear, and assume that emissions from brake wear are about the same; thus we assume that LDVs emit 0.4 g / mi PM, and buses 1.2 g / mi PM, from tirewear and brakewear combined. According to the EPA (*Air Emissions Species Manual, Volume II,* 1990), 55% of tirewear and brakewear PM is PM_{10}. The final emission factors therefore are 0.22 g / mi and 0.66 g / mi (Table 11).

The rate at which tires and brakes wear out, and hence the quantity of PM_{10} emissions per mile, is approximately proportional to the mass of a vehicle. (The tire-ground frictional force, and the force required to brake a vehicle, are proportional to the mass of a vehicle.) This means that a van will emit more PM_{10} from tire wear and brake wear than will a passenger car, and that a car with three people will emit more than a car with one person. To represent this properly, we model PM_{10} emissions as being proportional to vehicle mass. We assume that the LDV emission factors of Table 11 apply to a vehicle that weighs 3125 lbs, which is approximately the average weight of passenger cars in the U.S. (Delucchi, 1995a). Then, we estimate tire-wear and brake-wear emissions from any LDV in this analysis simply by scaling the factors of Table 11 by the ratio of the weight of the particular vehicle to 3125 lbs.

Road dust. Emissions of road dust per vehicle mile of travel are a function of the size and quantity of dust particles on the road, the size and speed of vehicles, and other factors. The EPA's emission factor handbook (AP-42, 1994) presents equations to calculate TSP (total suspended particulate) emissions from unpaved roads, paved urban roads, and paved industrial roads. In the equations for emissions from unpaved roads and paved industrial roads, emissions are expressed as a function of the weight of the vehicles, where the weight is raised to the 0.7 power[8]. The EPA equation for emissions from paved urban roads does not include weight or any other vehicle characteristic, but this is just a further analytical simplification. We assume that emissions from paved urban roads also are related to vehicle weight raised to the 0.7 power. (We validate this assumption below.)

Given that road dust emissions are related indirectly to vehicle weight, it follows that buses will cause much higher road dust emissions per mile than will passenger cars. We must use an equation that will represent this properly.

Furthermore, different types of roads typically contain different amounts of dust and silt. Local roads carry more silt than do freeways, and consequently a trip taken mainly on local roads will cause more PM_{10} road-dust emissions than will a trip taken on the freeway. This is relevant, of course, because a drive to the train station probably will involve relatively little freeway travel, compared to a direct drive door-to-door. The emission-factor equation also must allow us to represent this properly.

[8]In reality, emissions are determined not only by vehicle weight, but also by the number of wheels, the footprint of the vehicle, the clearance of the vehicle, the drag of the vehicle, and other characteristics. However, it is simplest to relate emissions to the most easily measured explanatory vehicle characteristic, which is weight. Thus, weight raised to the 0.7 power is a proxy for all vehicle characteristics that in theory directly determine road dust emissions.

In sum, then, we need an equation that contains vehicle weight and silt loading on roads as input parameters. Towards this end we have modified the EPA's (AP-42, 1994) equation for emissions from paved industrial roads:

$$R_v = 5.057 \times l \times k \times sL_v \times \left(\frac{W_v}{2.7}\right)^{0.7} \tag{9}$$

where:

R_V = emissions of PM_{10} from paved roads, in grams per mile of travel by vehicle v

k = PM_{10} fraction of emissions of total suspended particulate matter from paved roads (0.388; EPA, AP-42, 1994)

sL_V = travel-weighted average silt loading (g/m^2) on the roads traveled by vehicle v (Table 15; see derivation below, equation (10))

W_V = weight of the empty baseline gasoline or diesel vehicle v (in 10^6 grams) (Tables 1and 3)[9]

l = the width of a traffic lane (3.66 meters [12 feet]; FHWA, 1993)

v = Four different vehicle and trip combinations for which emission factors are calculated (passenger cars and vans used for door-to-door direct trips; passenger cars and vans used to access transit stations; buses used for line-haul; and buses used to access transit stations)

In order to calculate an average silt loading for different types of vehicles and trips (door-to-door by car or van; access to transit by car or van; line-haul by bus; access to transit by bus), we must know the distribution of travel and the silt loading by type of road. The EPA (AP-42, 1994) summarizes 44 measurements of silt loading (expressed in g/m^2) -- on local streets, collector streets, major streets and highways, and freeways and expressways in five cities. With these data, and assumptions about the distribution of vehicle travel, we calculate an overall silt loading by multiplying the average g/m^2 silt loading for each of the four types of roads by the fraction of mileage traveled on each type of road, and summing over all road types:

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[9]Note that we always input the empty weight of the baseline gasoline car or van or diesel bus, even if the vehicle actually being modeled for a particular trip is an alternative-fuel vehicle. This is because empty vehicle weight is a proxy for vehicle characteristics, such as size, that are the direct determinants of road dust emissions and which are more or less independent of the type of fuel and fuel storage system. A small car loaded with five passengers and two heavy CNG tanks in principle will cause less road-dust emission than a car that is larger but weighs the same because it carries only one person and no CNG tanks. The use of *empty* vehicle weight (or empty weight plus some constant payload) will properly reflect this; the use of actual loaded weights will not. (The weight of the passengers and CNG tanks will affect tire wear and brake wear; we have accounted for this here.)

$$sL_v = \sum_r sL_r \times M_{r,v} \quad (10)$$

where:

sL_v = travel-weighted average silt loading of roads traveled by vehicle type v

sL_r = average silt loading on road type r (g / m^2) (Table 15)

$M_{r,v}$ = total miles traveled on road type r divided by total miles traveled, for vehicle type v (Table 15)

Note that we assume different road / travel fractions for passenger cars versus buses, and for door-to-door trips versus access-to-transit trips.

We have checked the validity of using equation (9), which as we explained above is a modification of the EPA's equation for emissions from paved industrial roads, to estimate emissions from paved urban roads. Equation (9) is valid if it produces the same PM_{10} g / mi emission factor as does the EPA's equation for emissions from paved urban roads when the silt loading (sL) is the same in both equations and vehicle mass (W) in equation (9) is equal to the average mass implicit in the paved-urban-road equation. Presumably, the average mass implicit in the paved-urban-road equation is the travel-weighted mass of all vehicles -- light-duty, medium duty, and heavy-duty -- on urban roads. If the average vehicle mass on urban roads is assumed to be 5,000 lbs (e.g., 96% at 3200 lbs and 4% at 50000 lbs), and if the silt loading is 0.5 g / m^2, then equation (9) (in which vehicle mass is explicit) produces 3.18 g / mi, and the paved-urban-road equation (in which mass is implicit) produces 3.11 g / mi.

As a second check on our use of equation (9), we compare results from it with the EPA's (*National Air Pollutant Emission Trends, 1900-1992*, 1993) estimates of total emissions of road dust from all paved roads in 1991. We use equation (9) to estimate g / mi emission factors for each of six vehicle classes (passenger cars, motorcycles, buses, 2-axle 4-tire trucks, other single-unit trucks, and combination trucks; vehicle mass W_v in each class is taken from Delucchi [1995a], and the average silt loading sL_v for travel by each class is calculated using equation (10), with the $M_{r,v}$ estimated from FHWA [1993] data). We then multiply the g / mi emission factors by total miles of travel on paved road by each vehicle class (FHWA, 1993; we estimate that about 89% of all VMT is on paved roads), and sum over all classes. The result is 7732 tons of PM_{10} emitted from paved roads 1991. This agrees nicely with the EPA's estimate of 8150 tons of PM_{10} emitted from paved roads in 1991 (EPA, *National Air Pollutant Emission Trends, 1900-1992*, 1993).

"Track" dust from trains. Presumably, trains kick up dust from train tracks, just as cars kick up dust from roads. Unfortunately, the EPA's emission-factor handbook does not give emission factors for what we will call "track" dust. In order to estimate emissions of track dust, we assume that emissions of track dust from trains are the about the same as emissions of road dust from a bus, *per seat-mile of capacity*, given the

same amount of dust on the road and the track. Our reasoning is that track-dust and road-dust emissions are related to the footprint of the vehicle, and that the number of seats per square feet on a bus is close to the number of seats per square foot of a train. Thus, to estimate track-dust emissions from trains, we specify bus values in equation (9) (e.g., vehicle weight Wv = 33,000 lbs), and then divide the resultant g / mi estimate by 70 seats / vehicle, to produce g / seat-mile. Finally, we multiply this by the fraction of track mileage that we assume is at grade (because elevated and underground tracks do not produce dust).

Obviously, our estimates of track dust are little better than educated guesses, and could be really inaccurate. We hope, though, that they are better than an estimate of zero. In the scenario analyses presented later, we include scenarios of zero track-dust emissions.

4.2 Emissions from electricity generation

Total emissions from electricity generation are a function of the kind of fuel and technology used to generate electricity, the effectiveness of any emission controls used at the power plant, and the efficiency of generation and distribution and end use. Formally, gram / passenger-mile emissions of any pollutant p attributable to electric transportation are expressed simply as:

$$E = \sum_f w_f \times U_{f,p} \times C_{f,p} \text{x} H_f \times T \times V$$

where:

E_p = emissions of pollutant p attributable to transportation end use (grams per passenger mile)

w_f = power from fuel / plant type f divided by power from all sources (reflecting the “marginal” or “average” generation mix)

$U_{f,p}$ = uncontrolled emissions of pollutant p from fuel / plant type f (grams / 10^6 BTU fuel input [higher heating value])

$C_{f,p}$ = effectiveness of emission control (controlled emissions / uncontrolled emission) for fuel / plant type f and pollutant p

H_f = the generating efficiency of fuel / plant type f (BTU-electricity out / BTU-fuel in, higher heating value)

T = efficiency of electricity transmission and distribution (national average of 92%, according to historical data in the EIA’s *Annual Energy Review 1993,* 1994; we assume 94% for in-state generation, and 90% for imports).

V = end use energy efficiency (BTUs delivered electricity per passenger-mile of transport)

The data for each of these variables (except T) are discussed in the following subsections.

4.2.1 "Marginal" fuels and technologies used to generate electricity

The emissions attributable to any specific activity, such as the operation of light-rail transit trains, are those that would not have occurred had the activity in question not occurred. We will call these "marginal" emissions. Marginal emissions are associated with the use of marginal fuel and generation technology at power plants -- that is, with the fuel and plants that would not have been used had the activity in question not occurred.

Which fuels and plants will be marginal depend on many factors, including: the time, location, and magnitude of the marginal electricity demand; the cost, reliability, and availability of plants and electricity on the grid; and contractual and regulatory obligations. Many such factors are included the "Elfin" model used by the California Energy Commission (CEC) and Public Utilities Commission to examine the effect of changes in electricity demand on fuel use, emissions, and other outcomes[10]. We had the CEC run Elfin to simulate the effect of a uniform 1% increase in electricity demand, nominally due to increased use of power by mass transit systems, in the PG&E (Pacific Gas & Electric), LADWP (Los Angeles Department of Water and Power), SCE (Southern California Edison), and SDG&E (San Diego Gas & Electric) service areas, in the years 1993, 1998, 2003, and 2008. (Results were not available for the Sacramento Municipal Utility District.). For each utility and year, the CEC ran a base case, without the 1% increase in demand, and then modeled the 1% increase in demand. The differences in energy use between the with and without cases are attributable to the 1% increase in electricity use[11].

Table 16 shows the fuel-use results of this analysis -- the difference between the base case and the 1%-increase-case -- for the year 2003. (The results for the other years are not reproduced here. The Elfin output for the other years can be input into our emissions model to generate results for the other years. Details are given in the accompanying User's Guide to the model.) We have used all of the Elfin results for 2003 in our analysis.

We also have projected the year-2000 marginal generation mix for transit systems in Boston, Massachusetts and Washington, D. C. (Table 20). We have included these

[10]The datasets in the Elfin model represent typical conditions in a year. To the extent that conditions in the future are not like the "typical" conditions represented in Elfin, the Elfin output will be inaccurate. Also, the Elfin datasets include the CEC's projections of the *maximum* cost, not necessarily the most likely cost, of any additional resources required by utilities. Consequently, the Elfin output are not the CEC's official projections of capacity, emissions or fuel use.

[11]Of course, in reality the extra electricity demand of a new transit system will not simply bump up demand by 1% every hour, which is what Elfin modeled. For example, rail systems use more energy during peak hours than they do after the trains stop running for the night. Unfortunately, the CEC was not able to model a change in demand hour-by-hour. We note, though, that with rail systems the difference between peak and off-peak energy use might not be as large as one might expect, because nontraction energy use (e.g., for lighting stations) is independent of passenger load (and a large fraction of total energy use), and traction energy use is only weakly related to passenger load.

systems in the analysis because we have energy consumption data for vehicles and buildings and stations, and because the electricity mixes are different from the mixes in California and in the nation as a whole.

4.2.2 System "average" fuels and technologies used to generate electricity

Elfin did not model the marginal generation mix for the Sacramento Municipal Utility District (SMUD). For SMUD, then, instead of the marginal mix, we use the average mix in the year 2003, as projected by the California Energy Commission (Table 19). The average mix in a given time period is represented simply by total generation by all fuel and plant types (i.e., generation for all uses, not just for particular uses of interest.)

Of course, there is considerable uncertainty in estimating the marginal mix of electricity consumed by any particular activity, especially when one is trying to model such small changes in electricity consumption. In light of this uncertainty, it is worthwhile to calculate emissions for all cities (not just Sacramento) on the basis of the average rather than the estimated marginal electricity mixes. Here, we perform the emissions analysis for the projected average U.S. power mix (Tables 17 and 18), and for the projected average power mix in five California Utilities (Table 19).

For PG&E, LADWP, SCE, and SDG&E, the projected average (or total overall) generation mix (Table 19) can be compared with the marginal generation mix (Table 16). For all four utilities, the marginal in-state mix uses more natural gas than does the average or total overall mix. In other words, the Elfin model indicates that utilities would tend to ramp up gas-fired plants to meet a small incremental demand due to electric transport. Given that gas-fired plants generally are not run at maximum capacity around the clock (whereas nuclear and to a lesser extent coal plants are supposed to be), this does not seem unreasonable.

4.2.3 Emissions and emission control

The Elfin model, which we use to estimate future marginal power mixes for new electric transportation systems, also projects emissions of criteria pollutants from gas-fired power plants. Table 16 shows emission factors for gas power plants in the year 2003, associated with a 1% increase in electricity demand, derived from the Elfin model. We have used these emission factors in our analysis. However, Elfin generally estimates emissions from gas-fired plants only, and the CEC's *Electricity Report* does not have any emission factors at all. Therefore, for coal, oil, and biomass--fired plants, we projected average emission factors for the year 2000, using EPA's AP-42 (1994) factors for uncontrolled emissions, and our assumptions about emissions controls (Table 22). Note that the Elfin emission factors are reasonably consistent with controlled emission factors calculated from EPA's generic emission factors. (Note too that there are few data on emission of toxic air pollutants).

4.2.4 Efficiency of power generation

As shown in Table 16, the Elfin model projects that natural-gas boilers and turbines will be around 30-33% efficient (on a higher-heating-value basis), and natural-gas combined-cycle plants around 40% efficient, in the year 2003. (The results for other years, not shown here, are similar). Elfin does not estimate the efficiency of coal, oil, or biomass-fired power plants. For these plants, we estimated national-average efficiencies from data from the Energy Information Administration (EIA) (Tables 17 and 18). The EIA-based efficiencies also are around 30-33% for most conventional generation technologies.

4.2.5 Summary of use of data

With the Elfin, California-average, and national-average projections described above, we calculated grams of pollutant emissions per kWh of electricity delivered in Sacramento, San Francisco, Los Angeles, and San Diego (Table 24; the use of the various datasets is summarized in the note to Table 24). We use these emission factors to calculate emissions per passenger mile from the use of electric trains and electric vehicles, and emissions from petroleum refineries and alternative-fuel production plants.

4.3 Emissions from the production of liquid fuels

4.3.1 Emissions from petroleum refining

We have estimated emissions of criteria pollutants from petroleum refineries per gallon of gasoline, per gallon of diesel fuel, and per gallon of residual fuel oil produced. We have included emissions from refinery process areas, such as catalytic crackers, and from the generation of purchased electricity, as well as from the combustion of fuel (mainly refinery gas and natural gas) to raise heat. We started with CARB's (1991) estimate of emissions from refineries in 1989, allocated the emissions to different fuels (DeLuchi et al., 1992), and projected changes in emission controls by the year 2000. The assumptions and results of the analysis are presented in Table 25.

4.3.2 Emissions from the production of methanol and ethanol

Our analysis includes emissions of criteria air pollutants from facilities that produce methanol or ethanol transportation fuels. We estimate emissions for six different combinations of feedstocks and production processes: methanol from natural gas, methanol from coal, methanol from wood, ethanol from corn using coal to provide heat, ethanol from corn using biomass to provide heat, and ethanol from wood. In all cases we include emissions from the generation of bought electricity as well as on-site emissions.

Table 27 shows our calculated emissions from the six different kinds of methanol and ethanol plants, in grams per gallon of output, including emissions from electricity generation. It also shows weighted average emissions for a combination of different methanol plants and a combination of different ethanol plants.

When considering our estimates, keep in mind that emission factors for fuel production processes are a function of the specific technologies used, the operating conditions of the plant, and the type of emission control systems used. The emissions estimates of Table 27 might not apply to technologies different from those characterized in the original data sources that we used, or even to the same technologies or even plants under different conditions. Along these lines, we suspect that some of the seemingly high emission factors of Table 27 (e.g., for NMHC emissions from ethanol production) probably are not reliable.

4.3.3 Emissions from storage, distribution, transfer, and dispensing of liquid fuels.

We also estimates emissions of NMOG from spillage, leakage, evaporation, and vapor displacement from storage tanks, tanker trucks, and gasoline stations. For gasoline, we use the estimates of DeLuchi et al. (1992), who estimated emissions as a function of fuel characteristics, ambient temperature, storage and transfer techniques, the effectiveness and extent of emission controls, and other factors. Their analysis was targeted to the year 2000. For methanol and ethanol, we use DeLuchi’s (1991, 1993) assumptions regarding g/gal emissions relative to g/gal emissions associated with gasoline. The results of this analysis are shown in Table 28.

4.3.4 Emissions from the generation of electricity used to compress natural gas.

Emissions from the generation of electricity used to compress natural gas are counted as emissions from service stations. The electricity consumption of CNG stations is shown in Table 10. This electricity-use factor is multiplied by the appropriate metropolitan-area g/kWh emission factor (Tables 22 and 24).

4.4 Emission factors for natural gas and diesel-fuel use by buildings

We assume that the natural gas and diesel fuel used in buildings is used in residential furnaces or similar combustors. The emission factors for these devices are shown and documented in Table 29.

4.5 Emissions factors for toxic air pollutants

Toxic air pollutants are released from fuel combustion and solvent use, at virtually all stages of all fuelcycles. The California Air Resources Board (1993) provided us with estimates of emissions of toxic air pollutants in California in 1989 from all industries related to the production and use of fuels and vehicles. These data, presented in Table 12, can be used to estimate aggregate toxic emission factors: total emissions in a particular industry divided by some measure of output from or activity the industry. We have done this to calculate toxic emission factors for the petroleum-refining industry in California (Table 26). For electricity generation, we use the EPA's SPECIATE and XATEF (toxic air pollutants) databases to determine the amount and kind of toxic air pollution emissions.

4.6 Emissions of Greenhouse gases

To estimate emissions of greenhouse gases from automobiles, buses, power plants, and all other activities , we used results from the detailed greenhouse-gas emissions model developed by DeLuchi (1991, 1993), with key input variables set at their year-2000 values. The model includes emissions from the recovery and transport of primary energy feedstocks, the production of fuels from feedstocks, the distribution of fuels to end users, the end use of fuels in vehicles, the servicing and maintenance of transport modes, the building of major energy facilities (in the cases where the emissions were likely to be important), and the manufacture of materials for motor vehicles and the assembly of motor vehicles. (We will refer to all these stages together as a "fuel cycle".) It includes emissions of CO_2, CH_4, N_2O, CO, non-methane organic compounds (NMOCs), and oxides of nitrogen (NO_X).

Table 31 shows the greenhouse-gas emission factors output from the DeLuchi (1991) model. The factors are in grams of CO_2-equivalent emissions from the fuel-cycle, per million BTU of energy delivered to end users. These factors do not include emissions from the actual end-use of fuels; these emissions are calculated separately in the transit emissions model.

Implicit in our calculation of fuelcycle emissions of greenhouse gases are two assumptions: first, that a change of X gallons of demand for fuel F causes a change of X gallons of refinery output of F and a change in production of crude oil equal to the amount required to produce X gallons of F; and second, that emissions from U.S. producers and refiners are representative of the emissions from all of the producers and refiners affected by changes in U.S. transportation demand. Neither assumption is strictly correct, because price changes affect petroleum demand in nontransportation sectors, and because oil, fuels, and vehicles are produced and traded in a world market. We suspect but do not demonstrate that the error introduced by failing to account for the effect on prices and consumption in nontransportation sectors is relatively small. We are more confident that the second assumption is reasonable, because a change in U.S. demand likely will affect U.S. refiners mainly, and because in any case the energy intensity and emissions of oil production and refining in other countries is similar to that in the U.S. (Also, recall that in the case of global warming, the location of the emissions does not matter much.)

4.6.1 California-specific values.

DeLuchi's (1991) model comes with all the variables set at projected U.S. national-average values for the year 2000. Ideally, we would have re-specified all of the variables for California conditions, but this would have been a lot of work with little return, because there are many variables and for most of them California values are close to national values. Instead, we acquired and entered California-specific data for a few important variables, pertaining to energy use by oil refineries, and mode of shipment of crude oil to refineries. We compared the amount and kind of energy used by refineries in California with the amount and kind used nationally, and the modes of shipments of oil to California refineries with the modes of shipment of oil to refineries nationally (EIA, unpublished state-level data, 1993; EIA, *Petroleum Supply Annual 1991*,

1992) (Tables 32 and 33). On the basis of this comparison, we assumed that relative to refineries nationally, California refineries:

- consumed 5% more total process energy per unit of output than did national refineries, for all products;
- consumed less residual fuel oil, petroleum coke, and natural gas, but more LPG, refinery gas, marketable coke, and steam;
- received much more crude oil by tanker, and less by pipeline.

We also assumed that California refineries emit less VOCs and NO_x, per unit of product, than do refineries nationally.

4.6.2 Converting emissions of non-CO_2 greenhouse-gases to an equivalent amount of CO_2

In order to estimate the combined effect on climate of emissions of all of the different greenhouse gases, mass emissions of the non-CO_2 greenhouse gases -- CH_4, CO, N_2O, NMHCs, and NO_x -- are converted into the mass amount of CO_2 emissions that would cause the same degree-years of warming over a given period of time. The conversion factor has been dubbed a “global warming potential”, or GWP.

To calculate a GWP, one needs to know, for both CO_2 and non-CO_2 gases, the relationship between equilibrium surface temperature and equilibrium atmospheric concentration, and the relationship between an increase in yearly emissions and the increase in the equilibrium atmospheric concentration. One also must consider interactions between gases (for example, CO and CH_4), and the ultimate fate of the gases (CH_4 ends up being oxidized to CO_2 and H_2O by the OH^- radical). Finally, one must pick a period of time to do the analysis: because one is equating "degree-years" of warming over a period of time, the equation will depend on the length of time chosen. This choice is important.

The GWPs used in this analysis (nominally for a 100-year time horizon) are shown in Table 34, and are discussed in more detail in Delucchi (1995d). It is important to keep in mind that the GWPs, while quite useful, also are very uncertain, and may be revised in the future, perhaps substantially (Intergovernmental Panel on Climate Change, 1992).

4.7. Emissions from the construction of vehicles, facilities, and guideways

For two reasons, we do not estimate emissions from the construction of vehicles, facilities, or guideways. First, because the timing and location of emissions matters a great deal, one should not add or compare construction emissions, which occur over a relatively short period of time at the beginning of a project, to emissions from system operation, which occur after construction emissions and can continue for decades.

Certainly, it is not meaningful to annualize construction emissions and add them to emissions from operation, because neither pollution nor its effects act this way[12].

Second, the energy-use and emission-factor data needed for the estimation are poor. There is much disagreement about the energy requirements of guideway construction (Congressional Budget Office, 1977), and the emission factors for off-road construction equipment are not reliable (EPA, 1994).

5.0 ACCESS TO AND CIRCUITY OF TRIPS INVOLVING TRANSIT

5.1 Modes of access to line-haul transit

The total emissions of a trip that uses bus or rail transit for the line haul depend greatly on whether the traveler walks, drives, or takes a bus or train from her home to the main bus stop or rail station. We analyzed data from the *1991 Statewide Travel Survey* of California (Caltrans, 1993) in order to quantify how travelers accessed public transit, on average, in the San Francisco, Sacramento, Los Angeles, and San Diego regions.

Tables 35 to 39 show the results of the analysis. For each of six types of line-haul transit trips in the survey -- local bus, intercity bus, school bus, light rail, heavy rail (BART in the San Francisco area), and commuter rail (Caltrain in the San Francisco Area)[13] -- we show the fraction of trips accessed by each of 12 modes: walk, drive alone, car passenger, bicycle, local bus, intercity bus, school bus, light rail, heavy rail, commuter rail, dial-a-ride, and other mode. In order to match correctly modes of access to line-haul trips, we had to match trip starting and end times, for every person that reported taking transit. This reconstruction from original data of every transit trip recorded in the survey was very time consuming, but was the only way to quantify the distribution of modes of access to transit trips.

The analysis indicates that a surprisingly large fraction (65% to 85%) of bus and train passengers walked to the main bus or rail line, and that a relatively small fraction (10% to 20%) took a car. More people drove to train stations than to bus stops, and more people drove to BART than to any other mode, although the distribution of modes of access to light-rail stations was similar to that for BART. (We had expected that more people would have driven to BART). We caution, however, that there were so few transit users in the sample that the results might not be generalizable to the whole population. On-board surveys conducted in the 1970s and 1980s (and one conducted in Los Angeles in 1994) uniformly reveal that a greater percentage of transit users took a car to the stop or station than in our analysis (Table 40). Perhaps our results are skewed

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[12]Of course, by this argument, one really should not simply add emissions from different sources in a fuelcycle (e.g., petroleum refineries and vehicles), or compare emissions from one fuelcycle (e.g. gasoline) with another (e.g., methanol). Technically, this is correct. However, we feel that the timing and locational differences between emissions sources and fuelcycles are minor compared to the differences between construction emissions and operational emissions.

[13]Intercity rail -- AMTRAK -- also was included in the survey, but was not used as a line-haul by any of the respondents in the four regions. It was used as an access mode by one person.

because of the relatively small sample. In scenario analyses (section 6), we test a scenario in which all HRT passengers drive to the train station.

5.2 Circuity of trips involving transit

A trip made by transit will not be exactly the same length as the same trip made by automobile. The greater the difference in trip length, of course, the greater the difference in emissions.

It generally is assumed that trips involving transit are longer, or more circuitous, then trips by automobile. Table 41 summarizes estimates of the relative circuity of transit trips, and the portion of the total transit trip that is devoted to the mode of access, from the widely cited but somewhat outdated Congressional Budget Office (CBO) (1977) study of the energy use of urban transportation modes. We do not have much faith in these estimates, however. The CBO estimates appear to be educated guesses; no source is cited, and the CBO merely says automobiles "generally are the most direct form of urban passenger transportation" (p. 11). The CBO also cautions that the estimates are "highly variable and poorly documented" (p. 10). Furthermore, the CBO's estimates of circuity were strongly criticized by the New York Transit Authority and the American Public Transit Association in written testimony submitted to the Committee that sponsored the study. Finally, there is some evidence from the 1990 Nationwide Personal Transportation Survey (Vincent et al., 1994), that the circuity of carpools and vanpools is less than estimated by the CBO (Table 41).

5.3 Our assumptions

On the basis of the data in Tables 35 to 41, we estimated the length and modes of access to buses and trains (Tables 42 and 43).

5.4 A note on average auto occupancy and total person-trips by automobile.

Although we have not estimated "average" emissions per passenger mile of travel by auto (instead, we have analyzed different trip scenarios), it is possible to use our data and methods to do this, and to compare the result with the average emissions per passenger-mile of travel by transit. To estimate average emissions per passenger mile of travel, one must know either the "average" automobile occupancy, or else the total number of passenger-miles of travel by motor vehicles. These statistics often are reported in travel surveys, such as the Nationwide Personal Transportation Survey. However, as explained next, the average occupancy or total number of passenger miles, *as reported in travel surveys*, is not the correct measure to use.

As Vukich noted in testimony before the U.S. Senate (1977), the average automobile occupancy, and the total number of person-trips and passenger miles in motor vehicles, as determined by travel surveys, include trips by drivers who merely chauffeur someone else. These chauffeur trips actually should not be counted. Suppose, for example, that 10 fathers drive their kid to and from school each day, 2 miles one way. In travel surveys, this will be recorded as 120 person miles of travel. But if the parent does nothing other than chauffeur the child -- i.e., if the parent would not go out if the kid could get herself to school -- then the parent's is not a purposeful motor-vehicle trip, and should not be counted in comparisons with transit. If the children were to take transit, the parent would not go along, and there would be only 40 person-miles of travel (assuming the same distance by transit as by car). Now, if the transit vehicle uses as much energy as do the 10 motor-vehicles, then a correct measure of energy use per passenger mile gives the same result for the transit system as for the motor-vehicle system. This correct result will be obtained only if the chauffeur's person trips by car are not counted.

Thus, when comparing the "average" energy use or emissions or cost per passenger-mile of auto travel with the average for transit, trips by chauffeurs should not be counted.

6.0 RESULTS OF THE ANALYSIS

6.1 Summary of the base case

Table 45 shows the results of the "base-case" analysis. The percentage change in emissions is calculated as 100*(Tr-Ad) / Ad, where Tr is grams emitted per passenger trip involving transit, and Ad is grams emitted per direct door-to-door auto trip. A negative percentage change means that transit reduces emissions per passenger trip. The results of Table 45 include missions from fuel production and station and infrastructure operation and maintenance are included. For transit, emissions from access trips are included.

The base case uses the parameter values presented throughout this report (e.g., Tables 1, 3, 42, 43, 44). The base-case is just a scenario, not a prediction of fuels, modes, vehicle occupancy and other factors in particular regions. In the following sections we examine many other scenarios.

The base case uses CARB's EMFAC emission factors for the year 2003 (e.g., Tables 11 and 14). These emission factors incorporate CARB's assumptions about fuel quality and emission standards in the year 2003. The alternative fuel vehicles are assumed to be advanced-technology vehicles optimized to run on one fuel.

For the purpose of establishing an interesting base case, we have assumed that different regions will use different fuels and vehicle types. Our base-case assumptions about types of fuels (e.g., gasoline or electric vehicle) and types of cars (i.e., passenger car or van) are shown in Table 44. For example, we model EVs in the base-case for San Francisco. This, however, is just a scenario, not a prediction that EVs necessarily will be widely used in San Francisco.

The first and most important thing to notice about the percentage changes of Table 45 is that they vary considerably: transit uses causes increases in emissions of pollutants in some places and decreases in others, compared to direct automobile trips. For example, the use of LRT in Sacramento results in a considerable decrease in emissions of all pollutants except SO_X, whereas the use of HRT in Washington has a mixed effect. This is because the LRT system in Sacramento is more energy efficient than the HRT system in Washington (Table 4), and the electricity generation mix has less coal (Tables 16 and 20).

Next, note that LRT in San Diego does not provide quite as much as emissions reduction as does LRT in Sacramento. This is due partly to LRT being matched against CNG vehicles in San Diego, and gasoline vehicles in Sacramento; CNG is cleaner than gasoline (Table 12).

Wherever the occupancy of the direct-drive vehicle is high -- the carpools in Los Angeles, Boston, and San Francisco -- emissions from transit trips (at average transit-vehicle occupancy) tend to be higher than emissions from the direct-drive automobile trip. In the scenario analyses, we will examine the impact of increasing the occupancy of transit vehicles.

Finally, note that because we could not find data on emissions of emissions of acetaldehyde, 1,3-butadiene, and ethylene from power plants (Table 22), the percentage changes shown in Table 45 overstate the benefit of using electric transportation options.

In the next section we summarize the important parameters in the model, and in the sections after that we examine the effects of varying the values of these important parameters.

6.2 The important parameters

The preceding analysis of the base case, as well as the mechanics of our model, indicate that several parameters are important in the comparison of emissions from transit trips with emissions from direct-drive automobile trips:

- energy consumption per vehicle mile
- vehicle occupancy
- type of fuel used by cars, vans, or buses
- mix of fuels used to generate electricity
- mode of access to transit
- road dust and “track dust” emissions

In the following scenario analyses, we investigate the effect on emissions of varying these important parameters.

6.3 Scenario analyses

6.3.1 Base case. The same as the base case discussed above.

6.3.2 Base case without alternative fuels. In this scenario, all buses run on diesel fuel, and all cars and vans run on gasoline. Everything else is the same as in the base case (scenario 1). These changes from scenario 1 tends to make transit look somewhat better -- i.e., to reduce increases in emissions due to transit, or increase reductions -- because gasoline and diesel fuel are dirtier than alternative fuels. Put conversely, switching from conventional fuels to alternative fuels tends to reduce the advantage of transit, unless the alternative fuels are used in access trips and by transit buses, in which case the changes can be mixed (e.g., Los Angeles in this scenario).

6.3.3 Gasoline LDVs; no carpools; LRT transit. This case compares direct single-passenger trips in gasoline autos with trips involving light-rail transit, in which any motor-vehicle access to LRT stations is by single-passenger gasoline automobile or diesel-fuel bus. Everywhere except Boston, the LRT transit trip produces much lower emissions of every pollutant except SO_X than does the direct single-passenger gasoline-auto trip , because everywhere few people drive to LRT stations, and everywhere but Boston LRT uses relatively little energy. The LRT system in Boston apparently uses quite a bit of electricity (Tables 4 and 7; but note qualifications to estimates therein), which is produced from relatively dirty sources such as fuel oil (Table 20).

6.3.4 Gasoline LDVs; no carpools; HRT transit. This is the same as scenario 3, except that the transit trip is by heavy rail instead of light rail. Generally, the results are similar to the results of scenario 3. If the LRT system in a particular place is more energy intensive than is the HRT system (see Table 4), then it tends to produce higher emissions than does the HRT system (e.g., San Francisco and Boston), and vice versa. Overall, the trips involving HRT tend produce fewer emissions than do the direct single-passenger gasoline-auto trips.

6.3.5 Gasoline LDVs; no carpools ;diesel buses. This is the same as scenarios 3 and 4, except that the transit trip is by diesel bus instead of by rail. However, there are significant differences between the results of this scenario and the results of the rail scenarios. Buses emit more NMHC, CO, and NO_X than do power plants, and hence these emissions are higher (compared to single-passenger auto emissions) in this scenario than in the previous rail scenarios. In fact, NO_X emissions from the bus trip here are higher than NO_X emissions from the single-passenger gasoline auto trip. On the other hand, SO_X percentage changes decrease in this scenario compared to in the previous rail cases, on account of the use of low-sulfur diesel fuel by buses. PM_{10} emissions increase compared to the previous two rail cases, but because of road-dust emissions from buses, not tailpipe PM_{10} emissions. Still, PM_{10} emissions from buses are below PM_{10} emissions from the single-passenger gasoline auto trip.

6.3.6 Gasoline LDVs; no carpools; CNG buses. This is the same as scenario 5, except that all of the buses now use CNG instead of low-sulfur diesel fuel. This results in modest decreases in bus emissions across the board, compared to the previous diesel-fuel bus scenario, because CNG is somewhat cleaner than diesel fuel in every respect (Table 12).

6.3.7 Gasoline LDVs; EV vanpool to CNG buses. This is the same as scenario 6 except that in this scenario passengers who drive to the buses drive in an electric vanpool instead of a single-passenger gasoline auto. This results in trivial reductions in transit-trip emissions of almost all pollutants in all places, compared to the previous gasoline-auto-access scenario. The reductions are trivial because, even though the electric van has far lower emissions per passenger mile than does single-person gasoline auto (on account of both the lower per mile-vehicular emissions of the EV, and the higher occupancy of the van), on average very few people drive to buses (Table 43) , so that in the aggregate it hardly matters what they drive or how many are in the vehicle.

6.3.8 Gasoline LDVs; EV vanpool to LRT. This is the same as scenario 7, except that the transit trip is by LRT instead of by bus. This also is the same as scenario 3, except that those who drive to the LRT here drive in an electric vanpool instead of a single-passenger gasoline auto. The use of the electric vanpool results in minor reductions in LRT emissions compared to scenario 3. The reductions are minor because few people drive to LRT stops anyway (Table 43). However, the fraction who drive to LRT is greater than the fraction who drive to buses (Table 43), so that the reduction in transit-trip emissions caused by using EV vanpools in place of single-passenger gasoline autos is greater with LRT than with buses. The LRT scenario here remains somewhat cleaner than the bus system of the previous scenario.

Note that these last two scenarios are favorable to transit, and hence result in large reductions in emissions compared to driving directly by automobile.

6.3.9 Gasoline LDVs; EV vanpool to CNG buses; high-occupancy buses (best for buses). This is the same as scenario 7, except that the occupancy has been increased to 90% (cf. base case of Table 4). This of course substantially reduces emissions per passenger trip: bus transit emissions in this scenario are uniformly lower than bus transit emissions in scenario 7 (at the base-case load factor). Moreover, in this scenario, the per-passenger trip emissions from bus transit are everywhere lower than per-passenger-trip emissions from the direct single-passenger auto; in most cases, the reduction is over 80%. This case, which is the “best for buses” (because of the access by EV vanpool, as well as the high occupancy) demonstrates the obvious importance of the load factor for transit.

6.3.10 Gasoline LDVs; EV vanpool to LRT; high-occupancy LRT (best for LRT). This is the best case for LRT, similar to the best case for buses (scenario 9). Any access trips by car are in an EV vanpool; any access trips by bus are in a CNG bus. The load factors are 90% (cf. base-case factors of Table 4), and furthermore, “track-dust” emissions, the rail analog of road-dust emissions, are assumed to be zero (see section 4.1.9). Everywhere, emissions of every pollutant per passenger trip are near zero, except for SO_X emissions in Boston and Washington, D. C., because of the large amount of oil and coal in the fuel mixes there (Table 20).

6.3.11 Gasoline LDVs; EV vanpool to HRT; high-occupancy HRT (best for HRT). Analogous to scenario 10.

6.3.12 Gasoline vanpools; gasoline LDVs to diesel buses (worst for buses). This is the same as scenario 5, except that the direct-drive trip by gasoline automobile is a vanpool instead of a single-passenger car. This scenario in effect tests the results of increasing the occupancy of the direct-drive automobile trips rather than of the bus-transit trips. As expected, the effect is considerable. Bus transit now causes a substantial increase in emissions of every pollutant (except for ethene, which buses apparently do not emit [Table 13]), everywhere, whereas in scenario 5, in which the buses were matched against the single-passenger auto, bus transit reduced emissions of many pollutants.

6.3.13 Gasoline vanpools; gasoline LDVs to HRT. This is the same as scenario 4, except that the direct-drive trip by gasoline automobile is a vanpool instead of a single-passenger car. This scenario in effect tests the results of increasing the occupancy of the direct-drive automobile trips rather than of the heavy-rail transit trips. It is interesting to note that the effect in this scenario is not quite as dramatic as the effect in the case of bus transit (scenario 12 vs. scenario 5). For example, comparing HRT to vanpools rather than to single-passenger cars (this scenario vs. scenario 4) we find only a moderate effect on relative emissions of NMHCs and CO. This is because the HRT line-haul produces much less emissions of NMHCs, CO, and toxics than do cars or vans at any occupancy, because power plants produce essentially zero NMHCs, CO, and toxics. The only NMHCs and CO emissions from the HRT system come from the automobiles used to access the trains. Hence, total NMHC and CO emissions from HRT trips are so low that the occupancy of the direct-drive gasoline vehicle does not have a dramatic effect on the percentage change in emissions. In this scenario there also is little change in PM_{10} emissions over scenario 4, because trains (we assume) produce much less “track dust” than cars do “road dust”. On the other hand, in this scenario, HRT increases emissions of NO_X and GHGs, whereas in scenario 4 it decreased them, compared to the direct-drive gasoline vehicle trip. This is because power plants do emit lots of NO_X and GHGs, so that the occupancy of the competing mode (vanpool or single-passenger auto) does affect the percentage change in emissions per transit passenger trip.

6.3.14 EV vanpools; EV LDVs to HRT (worst for HRT). Scenario 13, though, still is not the worst for HRT. In this scenario, which is the worst, the competing direct-drive trip not only is a vanpool, but an electric vanpool. This is significant because now the inherent advantage of electric trains over gasoline autos -- near-zero emissions of NMHCs, CO, and toxics from power plants -- vanishes, because the direct-drive autos (the electric vanpools) now use electric power too. The result now is that HRT causes a substantial increase in emissions of every pollutant except PM_{10}. (PM_{10} does not increase because the dominant source is road-dust, which we assume greatly exceeds “track dust” emissions.)

6.3.15 EVs; EVs to HRT. This is the same as scenario 14, except that the direct-drive trip by automobile is a single-passenger EV, rather than a EV vanpool. Reducing the occupancy of the direct-drive auto trip back to one (compared to several in scenario 14) cuts the emissions increases caused by HRT, and in the case of NO_X and SO_X actually reverses them, to decreases relative to direct-drive by automobile. This scenario demonstrates again that the occupancy of the direct-drive automobile has a more noticeable effect on the comparison between auto and transit when the automobile and the transit use the same motive technology (either electric power or internal combustion for both).

6.3.16 Gasoline vanpools; high-occupancy buses. This is similar to scenario 5, except now both the buses and the direct-drive autos have high occupancy: the buses are 90% full, and the direct-drive automobile is a vanpool. Qualitatively, the emissions results of this scenario are similar to those of scenario 5, which means that the effects of the increased occupancies roughly cancel. The result of increasing the occupancy of both buses and door-to-door automobiles is that buses are slightly worse in Washington D. C., Los Angeles, and San Francisco, slightly better in Sacramento and Boston, and roughly the same in San Diego. The changes in relative emissions, however, are minor. Overall, one may conclude that one does just as well to increase automobile occupancy as to increase bus occupancy.

6.3.17 Gasoline cars; HRT with all access by gasoline auto. This is the same as scenario 4, except that everyone drives a single-passenger gasoline car to the train station (cf. base-case assumptions in Table 43). This causes a slight to large increase in emissions from HRT trips relative to emissions from direct-drive single-passenger auto trips. However, HRT still results in substantial reductions of emissions of every pollutant except SO_X everywhere. Thus, the fraction of people who drive to a rail station can affect the magnitude of the emissions reduction provided by HRT, but cannot switch the sign and cause HRT to increase emissions.

6.4 Conclusions

We have made a detailed model of emissions from transportation modes, in order to test the effects of transit use on emissions of several pollutants, in a wide range of situations. Depending on the values of key parameters -- energy use, vehicle occupancy, fuel type, mode of access, etc. -- the effect of transit use can range from a near elimination of all emissions per passenger trip to a substantial increase in all emissions per passenger trips.

It should come as no surprise that we cannot make sweeping generalizations about the effect of transit on air quality. (The most sweeping statement that we will venture is that rail transit generally will provide a substantial decrease in emissions of most pollutants.) Because the key parameters can assume vastly different values from one place or policy to another, the effect of transit must be analyzed case-by-case. The modeled developed here is a detailed enough to be a useful tool for case-by-case analysis.

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FIGURE 1. IDEALIZATION OF MODAL EMISSIONS FROM MOTOR VEHICLES OVER THE FEDERAL TEST PROCEDURE (FTP) (G/MI EMISSIONS VERSUS DISTANCE)

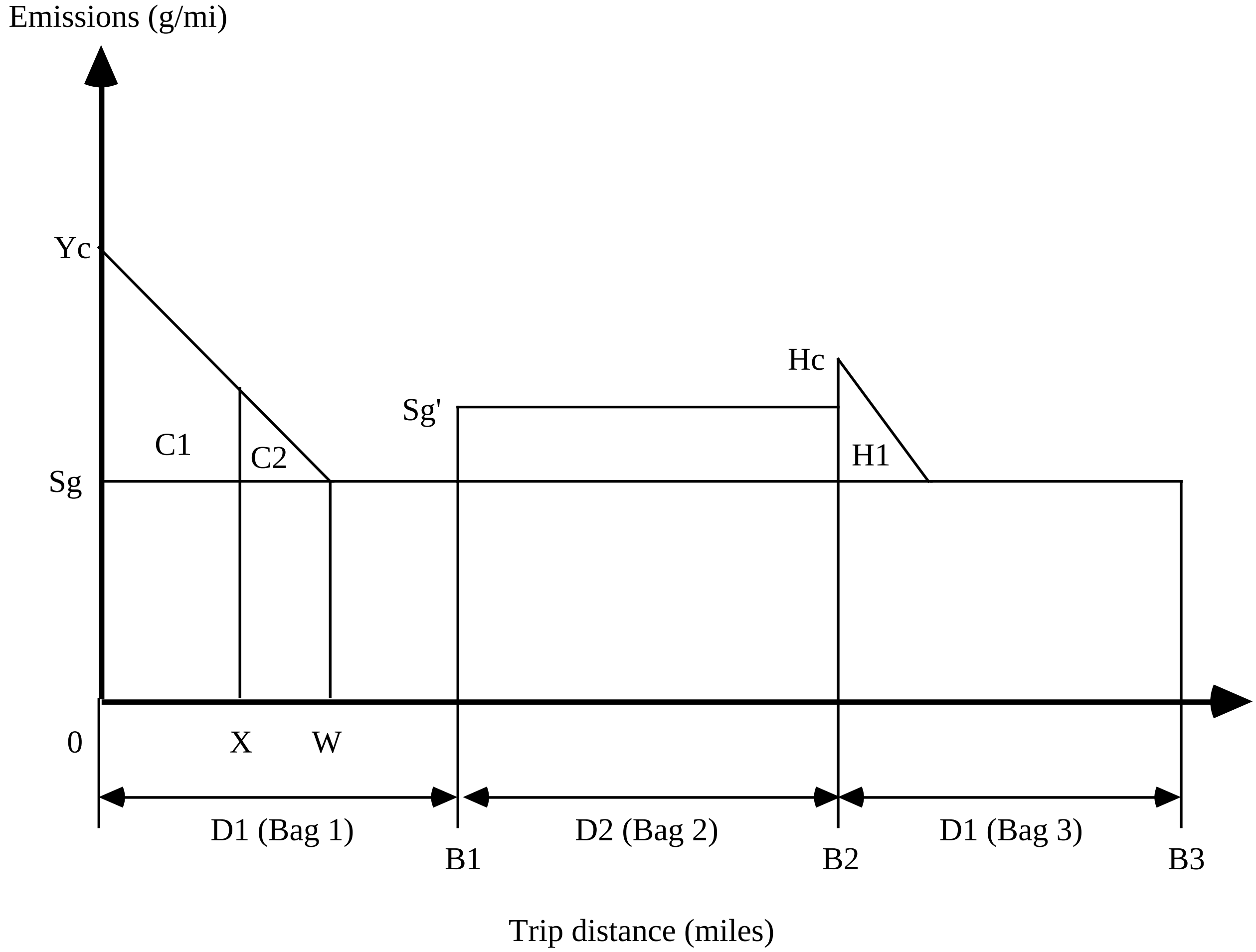

TABLE 1. FUEL USE BY LIGHT-DUTY CARS AND VANS: MODEL INPUT AND RESULTS FOR SACRAMENTO AND SAN FRANCISCO

	Sacramento		San Francisco	
Input vehicle parameters	*direct*	*access*	*direct*	*access*
Engine displacement (liters)	2.5	3.2	2.5	3.2
Thermal efficiency of gasoline engine (HHV, BTU / mi)[b]	0.37	0.37	0.37	0.37
Efficiency of the drivetrain	0.87	0.87	0.87	0.87
Efficiency of electrical system (for accessories)	0.5	0.5	0.5	0.5
Coefficient of drag	0.28	0.33	0.28	0.33
Frontal area (ft^2)	20.0	25.0	20.0	25.0
Empty weight of gasoline vehicle (lbs)	2750.0	3950.0	2750.0	3950.0
Number of people in car[a]	1.0	1.0	2.4	4.8
Weight per person (lbs)	150.0	150.0	150.0	150.0
Cargo (lbs)	0.0	0.0	0.0	0.0
Coefficient of rolling resistance	0.010	0.010	0.010	0.010
Accessory power, without air conditioning	0.50	0.60	0.50	0.60
Fraction of trip time that a / c is at full power	0.30	0.30	0.30	0.30
Revolutions per hour / mph (revolutions / mile)[b]	2508.0	2508.0	2508.0	2508.0
ICEV engine speed during idling (rpm)	750.0	700.0	750.0	700.0
Average speed in gear * relative gear ratio (mph)[b]	55.0	55.0	55.0	55.0
Engine energy consumption (kJ / revolution / liter, HHV)[b]	0.22	0.22	0.22	0.22
Correction factor for cold starts (kJ / revolution, HHV)[b]	1.10	1.10	1.10	1.10
Input trip parameters				
Length of trip, one way (miles)[d]	12.0	2.4	11.8	3.1
Fraction of trips that start with hot start	0.10	0.20	0.20	0.36
Fraction of trips that start with cold start	0.90	0.80	0.80	0.64
Average speed while moving (mph)[d]	40.77	33.98	28.28	22.54
Maximum speed (mph)	60.0	45.0	60.0	45.0
Number of stops per mile[e]	1.1	2.5	1.2	3.7
Fraction of trip time spent stopped[f]	0.190	0.209	0.209	0.240
Fraction of trip time that vehicle is coasting[f]	0.295	0.325	0.325	0.373
Fraction of trip time that engine is loaded[g]	0.705	0.675	0.675	0.627

Driving-cycle braking correction factor[b]	0.9	0.9	0.9	0.9

Calculated parameters				
Extra weight of AFV, divided by weight of empty baseline gasoline vehicle[h]	0.000	0.015	0.200	0.200
Thermal efficiency of selected vehicle relative to gasoline[h]	1.00	1.10	1.50	1.50
Total vehicle weight, including passengers (lbs)	2,900	4,160	3,661	5,463
Engine thermal efficiency (HHV)	0.370	0.407	0.555	0.555
Energy-use constant (kJ/revolution, HHV)[i]	0.605	0.704	0.000	0.000
Air-resistance coefficient (dimensionless)	0.0010	0.0013	0.0006	0.0009
Tire-resistance coefficient (dimensionless)	0.400	0.522	0.337	0.503
Braking coefficient (dimensionless)	1.839	2.398	0.928	1.385
Full power of air conditioning (kW)	3.17	3.78	3.17	3.78
Power for accessories and a/c (average kW over trip)	5.28	5.74	3.52	4.21
Average engine speed while vehicle is moving (rps)	30.7	29.7	29.9	28.4
Average vehicle speed over whole trip (mph)	33.0	26.9	22.4	17.1
Total time for trip (minutes)	21.8	5.4	31.7	10.8
Fuel consumption (kJ/meter, HHV)	3.25	4.42	1.41	2.54
Miles per million BTU (HHV)	202	148	464	258
Miles per gallon (mpg gasoline equivalent, for AFVs)	*24.6*	*18.1*	*56.7*	*31.5*

Source: our adaptation and specification of the model described in Ross (1994), An and Ross (1993), and Ross and An (1993). HHV = higher heating value; BTU = British Thermal Unit; AFV = alternative-fuel vehicle; a/c = air conditioning; ICEV = internal combustion engine vehicle. We assume that: i) a car used to access transit stations is smaller than a car used in the baseline door-to-door (direct) trip; but ii) a van used to access transit stations is the same as a van used in the baseline door-to-door (direct) trip, but carries fewer people. The “direct” columns labeled “direct” pertain to the vehicles that go door to door directly, from origin to destination. The columns labeled “access” pertain to the vehicles that go from home to a bus or train station.

The characteristics of the vehicles, and their calculated performance and emissions, depend of course on the type of fuel used (e.g., gasoline or CNG or electricity), and whether the vehicle is a van or passenger car or a carpool or vanpool. For the purpose of establishing an interesting base case, we have assumed that different regions will use different fuels and vehicle types. Our base-case assumptions about types of fuels (e.g., gasoline or electric vehicle) and types of cars (i.e., passenger car or van, or vanpool or carpool) are shown in Table 44. Note that these assumptions are just a base-case scenario, not predictions of which types of vehicles and fuels will be used in particular regions. For example, we model EVs in the base-case for San Francisco, but this is just a scenario, not a prediction that EVs necessarily will be widely used in San Francisco. (Note that in this table the EVs weigh more but also are more efficient than the gasoline ICEVs.) We actually run the model for a variety of scenarios.

[a]Rossetti and Eversole (1993) report the number of commute trips by 2-person vehicle pools, 3-person vehicle pools, and 4-plus-person vehicle pools in 25 major metropolitan areas in 1990. We assume that 4-plus-person pools carried 5 people on average, and then calculate the average occupancy in all vehicle pools (car pools and van pools) for the journey-to-work trip in Sacramento, San Francisco, Los Angeles, San Diego, Boston, and Washington, D. C. in 1990. Then, we assume that the average occupancy in carpools (whether for access trips or baseline direct trips) is equal to this calculated average, and that vanpools carry 2.5 times as many people as the average car pool for the baseline door-to-door trip, and 2.0 times as many for the access-to-transit trip.

[b]The values of these parameters are from Ross, An and Ross (1993) and Ross and An (1993). The values of the other parameters either our are assumptions or else are taken from a variety of standard data sources for motor vehicles. The parameter "Average speed in gear * relative gear ratio" is the speed (mph) of the vehicle, when in the highest gear, at which the engine speed is the same as it is in all other gears (Ross, 1994). It is simplified representation of a relationship between gear ratios and vehicle speed, and is used to calculate the number of engine revolutions, which in turn is multiplied by the energy consumption per revolution per liter, to estimate the total energy required to overcome engine friction.

[c]This is assumed to be zero for EVs.

[d]The average speed while moving is equal to the average overall speed over the whole trip divided by the fraction of time that the vehicle is moving. We use data on commute time and commute length by city, from the 1990 U.S. Census, the 1990 Nationwide Personal Transportation Study, and other sources (Rossetti and Eversole, 1993; Vincent et al., 1994; Gordon and Richardson, 1994) to estimate the length and average overall speed of the baseline (direct) trip by single-passenger vehicle. (We assume that for most trips, vehicles move about 80% of the time, and are stopped 20%.) Then, we use data on modes of access to transit and trip circuity (e.g., Tables 40 and 41) and some additional assumptions to estimate the length of transit-access trips and of carpool and vanpool trips, relative to the length of the baseline direct single-passenger vehicle trip.

[e]These our are assumptions and estimates. We assume that transit-access trips involve more stops per mile than do baseline direct trips, and that there is one stop to pick up each passenger in a van pool or car pool.

[f]For baseline direct trips by single-passenger autos or vans, we use An and Ross' (1993) and Ross and An's (1993) Federal-Test-Procedure values. We assume that the value increases with increased stop-and-go driving, so that it is higher for transit-access trips than for direct baseline trips, and higher for vanpools and carpools than for single-passenger autos.

[g]Equal to 1 minus the fraction of time coasting.

[h]These factors are used if an alternative-fuel vehicle, with a weight and thermal efficiency different from that of the gasoline vehicle, is specified.

[i] This is used to estimate the total frictional resistance (mechanical losses) and idling energy of an internal combustion engine, and therefore is assumed to be zero for an electric vehicle. Energy losses in the electric drivetrain are accounted for entirely in the efficiency term "Thermal efficiency of selected vehicle relative to gasoline" (see note g).

TABLE 2. FUEL, EMISSIONS, AND VEHICLE PARAMETERS FOR ALTERNATIVE-FUEL VEHICLES (BASE-CASE ASSUMPTIONS)

	Petrol.	MeOH	CNG	LPG
Light-duty alternative-fuel vehicles				
Engine efficiency relative to petrol. (mi / BTU, HHV)	1.00	1.15	1.1	1.1
Extra weight of AFV / weight of petroleum ICEV	0.00	0.00	0.045	0.015
Fraction of acceleration energy recovered by regenerative braking	0.00	0.00	0.00	0.00
Heavy-duty alternative-fuel vehicles				
Engine efficiency relative to petrol. (mi / BTU, HHV)	1.00	0.95	0.85	0.85
Extra weight of AFV / weight of petroleum ICEV	0	0	0.035	0.002
All alternative-fuel vehicles				
g-C / million BTU fuel	18,708	17,419	14,624	17,180
Carbon fraction in NMHC emissions	0.83	0.4	0.82	0.82
Emissions from normal incidental burning of lubricating oil in the engine (g / mi)	2.0	2.0	1.0	1.5
Upstream GHG emissions (g / 10^6 BTU)[b]	22,808	42,662	14,550	9,992

Notes: see next page.

Source of all estimates except "fraction of energy from biomass": DeLuchi (1991, 1993). Assumptions pertain to advanced AFVs optimized to run on a single fuel. Petrol. = petroleum (reformulated gasoline or low-sulfur diesel fuel); MeOH = methanol; EtOH = ethanol; CNG = compressed natural gas; LPG = liquefied petroleum gases; AFV = alternative-fuel vehicle; ICEV = internal-combustion engine vehicle; BTU = British Thermal Unit; C = carbon; HHV = higher heating value; NMHC = nonmethane hydrocarbons; GHG = greenhouse-gas n.a. = not applicable.

[a]This is the once-through efficiency of the electric charger, battery, controller, motor, and transaxle, relative to that of the gasoline-vehicle engine and transmission.

[b]These are CO_2-equivalent emissions of all greenhouse gases, from the entire fuel-production and use cycle. For each end-use fuel (petroleum, methanol, etc.), the g / 10^6-BTU fuelcycle emission factor shown here is equal to the g / 10^6-BTU factor for each feedstock (coal, natural gas, wood, or corn) that the fuel can be made from (Table 31), multiplied by the following assumed base-case feedstock fractions:

	End use fuel		
	Methanol	*Ethanol*	*CNG*
natural gas feedstock	0.75	0.0	0.95
coal feedstock	0.1	0.0	0.0
corn feedstock	n.a.	0.8	0.0
wood feedstock	0.15	0.2	0.05

These fractions are just assumptions, made to have an interesting base-case scenario.

TABLE 3. FUEL USE BY DIESEL BUSES

	Sacra-mento	San Francisco	Los Angeles	San Diego	Boston	Wash., D. C.
mpg of empty diesel bus[a]	3.18	2.39	2.83	3.23	3.45	2.50
Weight of empty diesel bus (lbs)[b]	33,000	33,000	33,000	33,000	33,000	33,000
Passenger capacity[c]	71	74	67	76	65	67
Actual number of passengers[c]	9	16	19	14	9	14
Weight per person (lbs)[d]	150	150	150	150	150	150
% change in mpg / 1% change in weight[e]	-0.55	-0.55	-0.55	-0.55	-0.55	-0.55

[a]We back-calculated the empty-weight mpg from:

$$Fe = \frac{Fa}{\left(1 + \frac{Wp \times P \times Cw}{Wb}\right)}$$

where:

Fe = fuel economy of empty bus (mpg)
Fa = actual fuel economy of bus with average number of passengers in fiscal year 1990 (mpg; Table 4)
Wp = weight per passenger (this table)
P = actual average number of passengers in fiscal year 1990 (this table)
Cw = % change in fuel economy per 1% change in bus weight (this table)
Wb = weight of empty bus (this table)

We need to know the empty-weight mpg, even though we know the actual mpg at the average load (Table 4), so that we can estimate the mpg with any load other than the average. We rearrange the formula above to estimate the loaded-weight mpg (for any load) as a function of the empty weight mpg and the number of passengers. (Of course, if one inputs the empty-weight mpg and the average number of passengers, the rearranged formula returns the actual average mpg, as it should.)

[b]The weight of the 26 heavy-duty vehicles (apparently mostly buses) tested by Wang et al. (1993) ranged from 31,000 lbs to 35,000 lbs.

[c]Actual data for fiscal year 1990, as reported to the Federal Transit Administration (Table 4).

[d]Our estimate.

[e]From studies reviewed in DeLuchi (1991, 1993), and other sources.

TABLE 4. ENERGY USE BY TRANSIT SYSTEMS, FISCAL YEAR 1990.

Transit system	Mode[a]	Diesel fuel 10^3 gal	Gas-oline 10^3 gal	Electricity 10^3 kWh	Vehicle revenue miles 10^3	Vehicle revenue capacity miles 10^3	Vehicle revenue hours 10^3
Los Angeles							
SCRTD	MB	31,598.8	0.0	0.0	86,591.6	5,701,190.7	6,953.6
SCRTD	DRP				6,912.7	62,214.7	470.1
SCRTD	MBP				3,035.7	176,069.8	211.3
San Francisco							
MUNI	CC	0.0	0.0	4,094.0	566.3	36,245.8	132.3
MUNI	DRP				1,435.7	16,566.3	138.9
MUNI	MB	5,568.2	0.0	0.0	12,809.2	943,761.5	1,374.7
MUNI	SC	0.0	0.0	43,338.1	4,092.8	556,626.0	385.4
MUNI	TB	0.0	0.0	35,121.0	7,355.5	551,665.9	988.7
BART	MBP				2,451.6	147,094.1	120.6
BART	RR	0.0	0.0	199,420.2	40,328.0	4,355,421.3	1,404.7
Golden Gate TD	FB	862.5	0.0	0.0	144.0	76,286.2	11.6
Golden Gate TD	MB	1,938.8	0.0	0.0	7,055.7	375,188.9	375.7
Golden Gate TD	MBP				434.3	19,532.0	15.8
Caltrans	FBP				97.5	38,988.4	7.7
Caltrans	CR	2,508.3	0.0	0.0	2,451.0	356,820.6	75.8
Sacramento							
Sacramento RTD	MB	2,135.1	2.2	0.0	6,596.6	471,194.8	480.4
Sacramento RTD	SC	0.0	0.0	7,200.0	1,373.0	240,273.4	72.1

San Diego							
San Diego TS	DRP				572.3	4,005.9	43.2
San Diego TS	MB	3,311.0	43.7	0.0	10,374.0	783,786.7	850.7
N San Diego Transit Dev	DR				549.8	6,992.9	34.6
N San Diego Transit Dev	MB	1,938.4	0.0	0.0	7,960.4	336,885.4	420.4
San Diego Region TS	DRP				2,457.6	16,690.8	156.4
San Diego Region TS	MBP				4,131.7	207,306.0	273.5
San Diego Trolley	SC	0.0	0.0	19,728.0	4,014.7	760,450.2	184.5
Washington, D. C.							
WMATA	MB	16,664.1	0.0	0.0	40,191.1	2,692,805.4	3,577.2
WMATA	RR	0.0	0.0	298,754.6	33,212.0	7,472,700.9	1,481.5
Boston							
MBTA	MBP				3,263.1	149,169.9	170.7
MBTA	DRP				1,793.8	n.r.	167.5
MBTA	FBP				121.3	59.8	9.1
MBTA	MB	6,703.9	0.0	0.0	22,644.7	1,471,904.7	1,876.8
MBTA	RR	0.0	0.0	143,853.1	23,186.3	3,451,282.2	1,098.9
MBTA	SC	0.0	0.0	36,146.1	1,295.0	226,549.9	116.9
MBTA	TB	0.0	0.0	3,389.9	745.3	48,447.7	57.4
Amtrak / MBTA	CR	7,487.0	0.0	0.0	13,186.1	1,577,210.4	505.6

Notes: see next page.

The data from the first nine columns, through "Passenger miles," are from the UMTA / FTA section 15 data base. We calculated average speed, load, and energy use. n.e. = not estimated. n.r. = not reported.

[a]The modes are:

CC = cable car	MB = motor bus
CR = commuter rail	RR = rapid rail
DR = demand ride	SC = street car
FB = ferry boat	TB = trolley bus

"P" after any of the above indicates purchased transportation.

[b]Equal to diesel-fuel consumption multiplied by 138,700 BTUs / gallon plus gasoline consumption multiplied by 125,000 BTUs / gallon plus electricity consumption multiplied by 3412 BTUs / kWh, divided by passenger miles. (Thus, the energy use measure presented here does not account for energy losses in electricity generation.) This is propulsion energy only; it does not include energy for stations, buildings, or maintenance activities. However, propulsion or traction energy does include energy used for nonrevenue operation, as for our purposes it should.

[c]Equal to energy use per passenger mile multiplied by the load factor.

TABLE 5. ENERGY USE BY TRANSIT SYSTEMS, FISCAL YEAR 1989

Transit system	Mode[a]	Diesel fuel *10^3 gal*	Gas-oline *10^3 gal*	Electricity *10^3 kWh*	Vehicle revenue miles *10^3*	Vehicle revenue capacity miles *10^3*	Vehicl revenu hours *10^3*
Los Angeles							
SCRTD	MB	27,979.6	0.0	0.0	86,149.7	5,851,000.0	6,861.5
Los Angeles County Transit	DRP				5,549.7	66,256.8	372.6
Los Angeles County Transit	FBP				0.0	0.0	0.0
Los Angeles County Transit	MBP				1,521.7	71,107.5	107.6
San Francisco							
MUNI	CC	0.0	0.0	3,826.2	554.7	35,502.2	130.3
MUNI	DRP				1,743.3	10,442.9	206.0
MUNI	MB	5,203.9	0.0	0.0	12,702.8	937,464.9	1,365.5
MUNI	SC	0.0	0.0	40,502.9	4,002.3	544,316.3	382.2
MUNI	TB	0.0	0.0	32,823.4	7,319.7	548,979.1	991.1
BART	MBP				1,170.7	70,244.8	55.8
BART	RR	0.0	0.0	172,259.6	33,195.1	3,817,436.4	1,158.1
Golden Gate TD	FB	779.6	0.0	0.0	138.1	72,467.3	10.8
Golden Gate TD	MB	1,838.3	0.0	0.0	6,825.9	374,757.7	360.7
Golden Gate TD	TMBP				423.9	19,024.5	15.5
Caltrans	CR	2,428.1	0.0	0.0	2,457.4	356,938.9	75.7
Sacramento							
Sacramento RTD	MB	1,729.8	38.2	0.0	5,863.6	418,898.1	420.9
Sacramento RTD	SC	0.0	0.0	6,899.2	1,059.8	184,458.7	53.6

San Diego							
San Diego TS	DRP				458.0	3,206.8	37.2
San Diego TS	MB	3,145.4	3.2	0.0	10,345.1	780,953.7	831.6
N San Diego Transit Dev	DRP				511.1	5,929.3	30.6
N San Diego Transit Dev	MB	1,877.1	0.0	0.0	7,828.0	335,819.3	403.9
San Diego Region TS	DRP				2,516.3	14,576.8	163.9
San Diego Region TS	MBP				3,334.2	146,215.8	206.7
San Diego Trolley	SC	0.0	0.0	11,297.7	2,366.5	507,682.5	125.5
Washington, D. C.							
WMATA	MB	16,432.5	0.0	0.0	39,350.2	2,636,460.3	2,860.7
WMATA	RR	0.0	0.0	295,240.9	32,859.0	7,393,277.3	1,405.5
Boston							
MBTA	MBP				799.8	n.r.	43.2
MBTA	DRP				3,008.4	3,575.2	330.8
MBTA	FBP				110.0	n.r.	6.5
MBTA	MB	7,183.8	0.0	0.0	23,239.7	1,505,896.1	1,958.8
MBTA	RR	0.0	0.0	148,853.1	21,857.5	n.r.	1,068.8
MBTA	SC	0.0	0.0	49,542.9	1,183.8	131,277.8	79.2
MBTA	TB	0.0	0.0	1,389.9	742.1	48,201.1	57.0
Amtrak / MBTA	CR	7,473.1	0.0	0.0	13,211.3	1,519,305.1	429.3

Notes: see next page.

The data from the first nine columns, through “Passenger miles,” are from the UMTA / FTA section 15 data base. We calculated average speed, load, and energy use. n.e. = not estimated. n.r. = not reported.

[a]The modes are:

CC = cable car	MB = motor bus
CR = commuter rail	RR = rapid rail
DR = demand response	SC = street car
FB = ferry boat	TB = trolley bus

“P” after any of the above indicates purchased transportation.

[b]Equal to diesel-fuel consumption multiplied by 138,700 BTUs / gallon plus gasoline consumption multiplied by 125,000 BTUs / gallon plus electricity consumption multiplied by 3412 BTUs / kWh, divided by passenger miles. Thus, the energy use measure presented here does not account for energy losses in electricity generation. This is propulsion energy only; it does not include energy for stations, buildings, or maintenance activities. However, propulsion or traction energy does include energy used for nonrevenue operation, as for our purposes it should.

[c]Equal to energy use per passenger mile multiplied by the load factor.

TABLE 6. ENERGY USE BY TRANSIT SYSTEMS, FISCAL YEAR 1988

Transit system	Mode[a]	Diesel fuel 10^3 gal	Gas-oline 10^3 gal	Electricity 10^3 kWh	Vehicle revenue miles 10^3	Vehicle revenue capacity miles 10^3	Vehicl revenu hours 10^3
Los Angeles							
SCRTD	MB	33,629.7	0.0	0.0	92,954.7	6,182,400.0	7,375.6
Los Angeles County Transit	DRP				2,389.7	17,222.5	152.1
Los Angeles County Transit	MBP				2,621.8	111,949.6	152.3
San Francisco							
MUNI	CC	0.0	0.0	3,831.0	544.9	34,872.6	128.3
MUNI	DRP				1,185.2	7,118.0	128.9
MUNI	MB	5,490.3	0.0	0.0	13,325.0	983,340.1	1,443.7
MUNI	SC	0.0	0.0	40,223.3	4,056.8	551,722.5	393.2
MUNI	TB	0.0	0.0	34,226.2	7,560.1	567,010.4	1,041.6
BART	RR	0.0	0.0	172,502.1	31,943.2	3,390,454.2	1,148.1
Golden Gate TD	FB	779.5	0.0	0.0	138.0	72,274.5	10.7
Golden Gate TD	MB	1,781.1	0.0	0.0	6,533.1	357,826.7	346.0
Golden Gate TD	MBP				422.1	20,263.1	15.5
Caltrans	CR	2,495.2	0.0	0.0	2,471.8	345,110.4	76.0
Sacramento							
Sacramento RTD	MB	1,907.5	45.3	0.0	5,917.8	420,167.1	423.5
Sacramento RTD	SC	0.0	0.0	8,644.5	936.2	163,832.2	47.0

San Diego							
San Diego TS	MB	3,143.4	34.8	0.0	10,782.7	668,921.7	816.9
San Diego TS	DRP				309.4	2,165.6	23.9
N San Diego Transit Dev	MB	1,780.7	0.0	0.0	7,651.4	522.6[d]	388.2
N San Diego Transit Dev	DRP				513.4	n.r.	32.4
N San Diego Transit Dev	DRP				5,064.0	46,170.3	347.0
N San Diego Transit Dev	MBP				640.2	37,131.9	56.5
San Diego Region TS	DRP				3,119.6	14,661.6	341.1
San Diego Region TS	MBP				919.8	27,674.2	46.5
San Diego Trolley	SC	0.0	0.0	9,669.6			
Washington, D. C.							
WMATA	MB	16,410.3	0.0	0.0	38,958.8	2,610,238.4	2,833.0
WMATA	RR	0.0	0.0	298,412.6	32,119.5	7,226,884.1	1,378.6
Boston							
MBTA	MB	7,910.7	0.0	0.0	23,387.3	1,515,140.3	1,972.8
MBTA	DRP				1,483.0	10,381.2	174.4
MBTA	FBP				71.9	6,333.0	4.0
MBTA	MBP				1,012.4	33,409.7	67.5
MBTA	RR	0.0	0.0	185,707.0	20,077.7	3,122,353.2	1,003.2
MBTA	SC	0.0	0.0	54,084.8	1,099.6	143,935.9	73.3
MBTA	TB	0.0	0.0	1,608.3	745.6	48,292.3	57.2
Caravan	VP				4,035.6	56,833.5	101.5

Notes: see next page.

The data from the first nine columns, through "Passenger miles," are from the UMTA / FTA section 15 data base. We calculated average speed, load, and energy use. n.e. = not estimated. n.r. = not reported.

[a]The modes are:

CC = cable car	MB = motor bus
CR = commuter rail	RR = rapid rail
DR = demand ride	SC = street car
FB = ferry boat	TB = trolley bus

"P" after any of the above indicates purchased transportation.

[b]Equal to diesel-fuel consumption multiplied by 138,700 BTUs / gallon plus gasoline consumption multiplied by 125,000 BTUs / gallon plus electricity consumption multiplied by 3412 BTUs / kWh, divided by passenger miles. Thus, the energy use measure presented here does not account for energy losses in electricity generation. This is propulsion energy only; it does not include energy for stations, buildings, or maintenance activities. However, propulsion or traction energy does include energy used for nonrevenue operation, as for our purposes it should.

[c]Equal to energy use per passenger mile multiplied by the load factor.

[d]This presumably is a typo, and should be 522,600. The original data are difficult to verify, and in any case, this particular datum is not used in this analysis.

TABLE 7. NON-TRACTION ENERGY USE BY SIX TRANSIT SYSTEMS

	Sacramento *Regional Transit*[a]	**San Francisco** *BART*[b]	**Los Angeles** *SCRTD*[c]	**San Diego** *Transit*[d]	**Boston** *MBTA*[e]	**Wasl D** *WM*
Bus	*FY 1990*	*FY 1989*	*FY 1988*	*FY 1991*	*FY 1990*	*FY*
electricity (kWh)	2,500,000	n.a.	48,000,000	3,482,893	12,610,000	19,6
diesel fuel (gallons)	2,647	n.a.	0	0	4,832	20
natural gas (SCF)	0	n.a.	75,811,013	9,422,087	0	
gasoline (gallons)	28,041	n.a.	800,000	103,940	48,321	214
Light rail						
electricity (kWh)	900,000	n.a.	n.a.	n.a.	14,550,000	n
diesel fuel (gallons)	953	n.a.	n.a.	n.a.	5,576	n
natural gas (SCF)	0	n.a.	n.a.	n.a.	0	n
gasoline (gallons)	10,095	n.a.	n.a.	n.a.	55,755	n
Heavy rail						
electricity (kWh)	n.a.	60,879,743	n.a.	n.a.	69,840,000	177,1
diesel fuel (gallons)	n.a.	84,000	n.a.	n.a.	26,762	41
natural gas (SCF)	n.a.	40,550,118	n.a.	n.a.	0	
gasoline (gallons)	n.a.	180,000	n.a.	n.a.	267,624	435
1000 passenger capacity miles[g]						
Bus	471,195	n.a.	6,182,400	801,658	1,471,905	2,61
Light rail	240,273	n.a.	n.a.	n.a.	274,998	n
Heavy rail	n.a.	3,817,436	n.a.	n.a.	3,451,282	7,22
BTUs/passenger-capacity-mile						
Bus						
electricity[h]	55	n.a.	80	45	88	
diesel fuel	0.8	n.a.	0.0	0.0	0.5	1
natural gas	0.0	n.a.	12.6	12.1	0.0	0
gasoline[i]	7.4	n.a.	16.2	16.2	4.1	1
Total for bus[j]	63	n.a.	109	73	93	
Light rail						
electricity[h]	39	n.a	n.a.	n.a.	545	n

diesel fuel	0.6	n.a.	n.a.	n.a.	2.8	
natural gas	0.0	n.a.	n.a.	n.a.	0.0	
gasoline[i]	5.3	n.a.	n.a.	n.a.	25.3	
Total for light rail[j]	44	n.a.	n.a.	n.a.	573	
Heavy rail						
electricity[h]	n.a	164	n.a.	n.a.	208	
diesel fuel	n.a.	3.1	n.a.	n.a.	1.1	
natural gas	n.a.	11.0	n.a.	n.a.	0.0	
gasoline[i]	n.a.	5.9	n.a.	n.a.	9.7	
Total for heavy rail[j]	n.a.	184	n.a.	n.a.	219	

Notes: see next page.

n.a. = not applicable (i.e., no bus or rail system); inc. below = included in the estimates below. BART = Bay Area Rapid Transit; SCRTD = Southern California Regional Transit District; MBTA = Metropolitan Boston Transit Authority; WMATA = Washington Metropolitan Area Transit Authority; FY = fiscal year; SCF = standard cubic foot. Passenger capacity miles are the same as revenue vehicle capacity miles (Tables 6 to 4).

[a]In fiscal year 1990, the Sacramento Regional Transit bus system used 2.5 million kWh of electricity, and the light-rail system used 0.9 million kWh of nontraction power (M. Lonergan, 1993). Non-revenue gasoline vehicles consumed 3178 gallons of gasoline in July 1990, and six nonrevenue diesel vehicles consumed a total of about 300 gallons per month (N. Fox, 1993).

[b]W. Belding (1993) provided the following data on the BART system:

	FY 1987	FY 1988	FY 1989
Million $, traction power	12.590000	10.703646	11.147025
Millions $, station & miscellaneous power	4.484551	4.004838	4.261582
Millions $, other utilities	0.813937	0.732208	0.836559

M. Epperson (1994) provided the following additional data:

	FY 1989	FY 1990
Millions kWh, station & miscellaneous power	65.336499	66.608617

Miscellaneous power includes power used by maintenance yards, shops, and the main administrative building. It does not include power used by leased buildings and some parking lots. To account for this other power, Epperson (1994) suggested multiplying by about 1.05 which we have.

Dividing FY 1989 expenditures on station and miscellaneous by FY 1989 power consumption indicates that BART spend $0.0653 / kWh for these uses. Dividing FY 1989 expenditures on traction power by FY 989 kWh for traction power (Table 5) indicates that BART paid $0.647 / kWh for traction power. This difference small difference, if real, is correct: BART gets a lower rate for traction power because the rail system takes power at the transmission-line voltage, without a voltage step-down (Epperson, 1994).

We assume that on quarter of BART's expenditures on utilities (other than electricity) were for natural gas, at $5.00 / 10^{6}BTU. (In SIC 75, automotive repair, expenditures on non-highway fuels actually exceed expenditures on utilities other than electricity [Bureau of the Census, *1987 Census of Service Industries, Capital expenditures, Depreciable assets, and Operating Expenses*, 1991], which suggests that at least half of BART's non-electricity utility bill could be for natural gas.) The EIA reports the following prices for natural gas in the Western U.S. in 1990 ($ / 10^{6}BTU, 1992$):

Region	*Residential*	*Commercial*	*Industrial*	*Transportation*	*All*
West South Central	5.78	4.41	2.78	3.32	2.96

From the EIA's *Supplement to the Annual Energy Outlook 1994* (1994).

Finally, BART vehicles consumed 15,000 gallons of gasoline and 7000 gallons of diesel fuel per month, over 6 months in 1988 and 1989 (M. Door, 1993).

[c]In FY 1988, Southern California Regional Transit District spent $3.36 million for all power and $0.0391 million for natural gas (F. Hadden, 1993). As explained in note b above, we assume $5.00 / 10^6BTU for natural gas. On the basis of the following data, we assume $0.07 / kWh for electricity:

Region	*Residential*	*Commercial*	*Industrial*	*Transportation*	*All*
California	0.089	0.086	0.067	0.051	0.080
New England	0.097	0.087	0.073	0.070	0.087

From the EIA's *Supplement to the Annual Energy Outlook 1994* (1994).

According to J Bowie (1993) of SCRTD, in most years SCRTD nonrevenue vehicles use 800,000 gallons gasoline and very little diesel fuel.

[d]The data shown are for FY 1991 (July 1990 to June 1991) (R. Perez, 1993). San Diego Transit paid $5.83 / 10^6 BTU for gas and $0.077 / kWh for electricity.

[e]The Metropolitan Boston Transit Authority consumed 101 million kWh and 82 million SCF of natural gas for nontraction purposes in FY 1990, excluding energy used for construction (N. Polcari, 1993; D. McCormick, 1995). Nonrevenue gasoline vehicles used 371,700 gallons of gasoline in FY 1991, and non-revenue diesel vehicles consumed "about 10%" of that amount (M. Dipaulo, 1993). We assigned 13% to bus, 6% to light rail (streetcar and trolley bus), and 81% to heavy rail (subway). (A small amount of the non-traction electricity actually powers AMTRAK stations; we ignore this here.) Traction energy: 76% of kWh usage is RT lines. Trolley and Street car is 23%. 1% to AMTRAK.

[f]WMATA (P. Reed, 1993) provided us with data on total consumption of gasoline, diesel fuel, and electricity for all stations, non-revenue vehicles, buildings, and maintenance facilities for the entire WMATA rail-and-bus system combined, in FY 1988. Then, they estimated that bus operations consumed 33% of the total gasoline and diesel fuel, and rail operations 67%. They also told us that "most" of the non-traction electricity use reported should be allocated to the rail system. We assumed 90%.

WMATA paid $0.05 / kWh for electricity.

[g]From the Federal Transit Administration (1992).

[h]Electricity counted at 10,300 BTUs / kWh. Here this is just an accounting convention, applied to electricity to be able to add up all BTUs to get a bottom-line BTU total. In calculating emissions, however, we revert to the original kWh data; that is we calculate emissions due to electricity by multiplying actual kWh of electricity use per passenger mile by the marginal emissions rate per kWh delivered from the power plants in the particular region (e.g., Table 24).

[i]We assume conventional gasoline for these calculations.

[j]BTUs per passenger-capacity mile are divided by load factors (Table 4) to obtain BTUs / passenger mile, which of course are used to calculate the final results (Table 45).

TABLE 8. ESTIMATES IN THE LITERATURE OF STATION AND MAINTENANCE ENERGY USE BY TRANSIT SYSTEMS

System (reference)	**Fraction of total station + maintenance + vehicle**	
	vehicle operation	*Station and maintenance*
New heavy rail (subway and at grade)		
Bay Area Rapid Transit District (Fels, 1978)	0.71	0.29
Bay Area Rapid Transit District (Curry, 1976)[a]	0.66-0.76	0.24-0.34
Bay Area Rapid Transit District (this report)	0.55	0.45
Washington Metro (this report)	0.39	0.61
Los Angeles Metro Rail (Westec Services, 1983)[b]	0.54	0.46
Rapid transit below grade (Reno and Bixby, 1985)[c]	0.55-0.74	0.26-0.45
Rapid transit at grade (Reno and Bixby, 1985)[c]	0.79-0.91	0.09-0.21
Old heavy rail		
New York Subway (Fels, 1978)	0.86	0.14
PATH (New Jersey to New York) (Fels, 1978)	0.89	0.11
New commuter rail (at grade)		
PATCO Lindenwold line (Fels, 1978)	0.85	0.15
PATCO Lindenwold line (Curry, 1976)[a]	0.78	0.22
Light rail transit		
Light rail transit at grade (Reno and Bixby, 1985)[c]	0.67-0.85	0.15-0.33
Sacramento LRT (at grade) (this report)	0.86	0.14
Bus		
Sacramento Regional Transit (this report)	0.90	0.10
Southern California Regional Transit District (this report)	0.86	0.14
San Diego Transit (this report)	0.88	0.12
Washington Metropolitan Area Transit Administration (this report)	0.90	0.10

In general, there is some question as to the best way to add up electrical energy and energy from other sources, such as natural gas. However, for all of the systems included in this table, electricity is the main energy source for stations and maintenance as well as for vehicles, and in some cases, it is the only energy source. A relatively minor amount of natural gas, diesel fuel, and gasoline is used to heat buildings and fuel non-revenue vehicles. Because all or nearly all of the energy is electrical, the issue of converting to "common" BTUs is not important. Nevertheless, as far as we can tell, where necessary electricity has been converted at around 10,000 BTUs / kWh (the average heating rate of power plants) and added to the heat value of other fuels, which is a reasonable approach.

[a]Curry (1976) cites original energy impact analyses. Curry says that regenerative braking can return “up to” 20% of propulsion energy; we assume 0% to 10%.

[b]The station and maintenance energy requirements are relatively high because all of the stations are subway stations. By contrast, many BART and Washington-Metro stations are above ground. Subway stations consume more energy than above-ground stations because they use more lighting, elevators, and escalators.

[c]Reno and Bixby (1985) cite the 1982 book *Urban Rail in America*, by Pushkarev et al. In all cases, the range of values depends on the speed of vehicle operation; at higher speeds, the maintenance and station energy fraction declines.

We assume that the Pushkarev et al. estimates refer to new rail systems.

Calculated from the data of Tables 6 to 4 and Table 7, and data (not shown) from the FTA (1992). We have assumed 10,300 BTUs / kWh.

TABLE 9. CALCULATION OF ELECTRICITY AND FUEL USE IN SICS 517, 554, 55 (EXCEPT 554) AND 75, IN 1987

SIC: description	Electricity		Natural gas		Fuel oil	
	expense (10^6\$)[a]	*price* (\$/kWh)[c]	*expense* (10^6\$)[a,b]	*price* (\$/SCF)[d]	*expense* (10^6\$)[a,b]	*price* (\$/gal)[e]
517: Petroleum marketing	151	0.0600	84	0.00400	25	0.60
554: Service stations	666	0.0677	112	0.00563	33	0.71
55[f]: Motor vehicles, parts	750	0.0677	243	0.00563	73	0.71
751,754[g]: Leasing, services	165	0.0677	65	0.00563	19	0.71
752[g]: Parking	21	0.0677	5	0.00563	1	0.71
753[g]: Repair	281	0.0677	118	0.00563	35	0.71

[a]These data are from the Bureau of the Census' quinquennial surveys: data for SIC 517 are from the *1987 Census of Wholesale Trade, Subject Series, Measures of Value Produced, Capital Expenditures, Depreciable Assets and Operating Expenses* (1991); data for SICs 554 and 55 except 554 are from the *1987 Census of Retail Trade, Measures of Value Produced, Capital expenditures, Depreciable assets, and Operating Expenses* (1991); and data for SICs 751-754 are from the *1987 Census of Service Industries, Capital expenditures, Depreciable assets, and Operating Expenses* (1991).

The expenditure estimates published from these surveys are actual, direct payments for electricity and fuel; they do not include the cost of any electricity and fuel that was included in normal lease or rental payments or franchise fees. Therefore, the published expenditure estimates need to be scaled up to account for the use of electricity and fuel that was paid for in lease, rental, or franchise fees and hence did not show up in the published expenditures. Because the Census does not have any data on the cost of energy included in lease, rental, or franchise fees, this scaling must be done indirectly, as explained next.

The Census does have unpublished data that allow one to calculate the ratio of: total operating expenses for all firms in the SIC of interest (that is, operating expenses of firms that paid for electricity and fuel, *plus* the operating expenses of firms whose electricity and fuel use was covered by lease, rental, or franchise fees) to the operating expenses of firms that reported only direct payments for electricity and fuel (Bureau of the Census, Business Division, personal communication, 1993). We assume that this ratio is equal to the ratio that we would really like to know, namely: payments for all electricity and fuel (including the cost of electricity and fuel covered in lease, rental, or franchise fees) to reported actual payments for electricity and fuel. Therefore, we multiply reported direct payments for electricity and fuel in each SIC by the ratio of total operating expenses of all firms to operating expenses of firms that reported direct payments for electricity and fuel, in each SIC.

[b]The Census shows only total expenditures for all fuels other than electricity; it does not distinguish natural gas from fuel oil. We use data from the EIA's *Manufacturing Energy Consumption Survey* to estimate the portion of fuel expenditures that is for natural gas, and the portion that is for fuel oil. In 1986, mercantile and service commercial buildings in the U.S.

consumed 0.536 quads and 10.58-billion-dollars-worth of electricity, 0.332 quads and 1.61 billion-dollars-worth of natural gas, 0.105 quads and 0.489 billion-dollars-worth of fuel oil, 0.012 quads of district heat, and 0.017 quads of propane (EIA, *Annual Energy Review 1993*, 1994). Based on this, we assume that in 1987, 23% of the payment for "other fuels" as reported by the Census was for fuel oil, and that 77% was for natural gas.

The Census also provided information on operating expenses that included use of "fuels not applicable." We have assumed that this refers to highway fuels, which we wish to include in our totals, so we have estimated payments for these fuels and have included them in the totals shown for fuel oil.

[c]In 1987, the average electricity price in the U.S. in the commercial sector as a whole was \$0.0708 / kWh, and in 1986 the average electricity price to mercantile and service commercial buildings specifically was \$0.0686 / kWh (EIA, *Annual Energy Review 1993*, 1994; the figure for 1986 is from the Commercial Buildings Energy Consumption Survey, which was done in 1986 and 1989 but not 1987). The price to mercantile and service buildings in 1987 can be approximated as the price in 1986 multiplied by the ratio of the price to the commercial sector as a whole in 1987 to the price to the commercial sector as a whole in 1986. This results in \$0.0677 / kWh, which we use as the average electricity price in SICs 554, 55 except 554, and 75.

We assume that the price to SIC 517 is between the commercial-sector average price of \$0.0708 / kWh and the industrial-sector average price of \$0.0477 / kWh (EIA, *Annual Energy Review 1993*, 1994).

[d]We estimate the average natural gas using the same data source (EIA, *Annual Energy Review 1993*, 1994) and methods that we used to estimate the average electricity price (footnote c). The relevant price data for natural gas are: \$4.77 / 1000-SCF (Standard Cubic Feet) to the commercial sector in 1987 and \$5.08 in 1986; \$5.29 / 1000-SCF to mercantile and service buildings in 1986; and \$2.94 / 1000-SCF to the industrial sector in 1987.

[e]I estimate the average fuel-oil price using the same data source (EIA, *Annual Energy Review 1993*, 1994) and methods that I used to estimate the average electricity price (footnote c).The relevant price data for fuel oil are: \$0.803 / gallon for residential heating oil in 1987, and \$0.836 in 1986; \$0.685 / gallon for "fuel oil" sold to mercantile and service buildings in 1986 (we assume 140,00 BTU / gallon HHV); and \$0.527 / gallon for No. 2 fuel oil sold from refiners to resellers in 1987, and \$0.486 / gallon in 1986.

[f]Excluding SIC 554, which is covered separately.

[g]The Census reported electricity and fuel expenditures in all of SIC 75, electricity and fuel expenditures in SIC 753, and electricity expenditures in SIC 754. We subtracted energy expenditures in SIC 753 from total energy expenditures in SIC 75, and apportioned the remaining energy expenditures among SICs 751, 752, and 754 according total operating expenditures (which were reported for all SICs).

TABLE 10. CALCULATION OF ENERGY USE FOR AUTO SERVICES, PER UNIT OF FUEL OR MILE OF TRAVEL

	Electricity (kWh)	**Natural gas** (SCF)	**Fuel oil** (gallons)
Energy use per 10^6 BTU of liquid fuel[a]			
Marketing (SIC 517)[b]	0.090	0.757	0.0015
Service stations (including repair) (SIC 554)[c]	0.812	1.636	0.0039
Energy use per 10^6 BTU of CNG			
Service stations excluding compression[d]	0.416	1.636	0.0039
Compression of natural gas[e]	6.450	0.0000	0.0000
Energy use per vehicle mile -- all vehicle types[f]			
Motor vehicle and parts sales; repair done at dealers and parts stores (based on SIC 55 except 554)[g]	0.0060	0.0232	0.00005
Auto services (based on SICs 751,754)[h]	0.0063	0.0300	0.0001
Commercial parking (based on SIC 752)[i]	0.0035	0.0095	0.0000
Auto repair n.e.c. (based on SIC 753)[j]	0.0024	0.0120	0.0000
Non-commercial parking (1990 data)[k]	0.0039	0.0000	0.0000

All values shown are equal to dollar expenditures on electricity or fuel divided by price (per kWh, SCF, or gallon) divided by total activity or quantity (BTUs or miles). Expenditure and price data are from Table 9. Activity data are documented in the notes to this table. SCF = standard cubic foot; SIC = standard industrial classification; CNG = compressed natural gas. Construction energy is not included anywhere in this table.

[a]We express energy consumption at petroleum storage plants and service stations per million BTU because that most accurately represents the real functional relationship: the more fuel stored or dispensed, the greater the energy usage at service stations and marketing facilities. Energy consumption at these facilities is not directly related to VMT because of the intervening effect of fuel economy (miles per 10^6 BTU). However, if you wish to know energy consumption per VMT, to compare with the energy consumption per VMT calculated for the other SICs, convert the result shown here to energy / gallon and then divide by 15.06 fleet-average mpg in 1987.

[b]We assume that electricity and fuel use at liquid-bulk-storage facilities is proportional to the amount of fuel handled. In 1987, SIC 517, petroleum bulk storage, sold 222.7 billion gallons of fuel (Bureau of the Census, *1987 Census of Wholesale Trade, Miscellaneous Subjects*, 1991). We

assume that all highway fuels pass through a bulk-storage facility, and that no gallon of any fuel is sold twice within SIC 517. We also assume that SIC 517 handles only petroleum products, and that there is no bulk storage of highway fuels outside of SIC 517. With these assumptions, the amount of energy used at bulk storage facilities per unit gallon of highway fuel consumed by end users -- which is the number that we want -- equals the total amount of energy (of each kind) consumed in SIC 517 divided by the total amount of gallons sold in SIC 517. The electricity and fuel-use and the gallon-sales data for SIC 517 are from the same general survey, but it appears that the definition of "petroleum bulk stations and terminals" used in the electricity and fuel-use part of the survey (Bureau of the Census*1987 Census of Wholesale Trade, Measures of Value Produced, Capital expenditures, Depreciable assets, and Operating Expenses,* 1991) is slightly different than the definition used in the gallon-sales part of the survey (Bureau of the Census, *1987 Census of Wholesale Trade, Miscellaneous Subjects,* 1991). Nevertheless, we use electricity and fuel use data from the *Measures of Value Produced...*report, and gallon data from the *Miscellaneous Subjects* report. We have scaled the reported gallon sales by the ratio of total sales to reported sales.

These energy use factors do not include diesel fuel used by tanker trucks.

[c]We assume that electricity and fuel use at service stations is proportional to the amount of liquid-fuel energy dispensed. (Fuel used for repair at service stations probably is more directly related to VMT. However, we assume that repair work accounts for a minority of the energy use at service stations.) In 1987, service stations in SIC 554 sold 87.26 billion gallons of fuel (Bureau of the Census, *1987 Census of Retail Trade, Measures of Value Produced, Capital expenditures, Depreciable assets, and Operating Expenses,* 1991). The gallon-sales data and the electricity and fuel-use expenditure data are from the same survey (Bureau of the Census, *The 1987 Census of Retail Trade,* 1991) and pertain to the same population of service stations. However, businesses in SIC 554 sell more than just highway fuels, repair services, and automotive supplies: in 1987, food, drinks, drugs, household merchandise, and other non-automotive goods were slightly more than 10% of the sales in SIC 554 (Bureau of the Census, *1987 Census of Retail Trade, Subject Series, Merchandise Line Sales,* 1990). On the assumption that people would buy these non-automotive products elsewhere if they did not drive, we deduct the product's share of electricity and fuel usage, which we assume is equal to the products' share of total sales. Therefore, we allocate 90% of electricity and fuel use at service stations (SIC 554, which includes truck stops) to the 87 billion gallons of fuel sold in this SIC in 1987.

These energy-use factors do not include diesel fuel used by tanker trucks.

[d]This is the difference between the total electricity consumed at gasoline service stations and the amount of electricity used to pump gasoline. We estimate that pumping-power consumption is about half of total power consumption at service stations. We assume that a CNG station would use the same amount of non-pumping energy per 10^6 BTU of CNG as a gasoline station does per 10^6 BTU of gasoline.

[e]We assume 0.022 BTU-electricity per BTU-CNG, on the basis of a revision of the analysis in DeLuchi (1993).

[f]We assume that the amount of electricity and fuel used at motor-vehicle dealerships, automotive parts stores, repair shops, parking lots, administrative buildings, and so on, is

related directly or indirectly to total vehicle miles of travel. In most cases, this is a reasonable assumption. For example, energy use by repair shops, parking lots, and most motor-vehicle services probably is proportional to VMT. Energy use at motor-vehicle dealerships probably is more directly related to the total numbers of vehicles sold, but VMT in turn probably is related to vehicle sales, and in any case is easier to work with.

Further on in the analysis, we estimate emissions attributable to these activities (motor-vehicle sales and service, etc.) by multiplying these energy-use factors by emission factors. We do this for alternative-fuel vehicles as well as for gasoline vehicles, on the assumption that alternative-fuel vehicles require the same amount of energy per mile for auto sales and support and so on as do gasoline vehicles.

[g]Our energy-use measure is: all energy associated with the sale of motor vehicles, the sale of motor-vehicle parts, and motor-vehicle repair done at motor-vehicle dealers and parts stores, in 1987, divided by total VMT of 1.9212 trillion in 1987 (FHWA, *Highway Statistics 1988*, 1989). The Census data for SIC 55 (except 554) of Table 9 do not cover *all* of this relevant energy use, because some motor vehicles and parts are sold in other industries (such as department stores). Furthermore, a small fraction of the sales in SIC 55 (except 554) are not related to motor-vehicle use. To account for both of these problems, we adjust electricity and fuel consumption by multiplying electricity and fuel consumption in SIC 55 (except 554) by the ratio of dollar sales of all automotive merchandise lines in all SICs (except 554) to dollar sales of all merchandise in SIC 55 (except 554). (1.034; from Delucchi, 1995b).

[h]We have multiplied energy consumption in SICs 751 and 754 by five, to account for the energy consumption of automobile insurance companies, highway maintenance and lighting, motor-vehicle departments, and police, fire, and justice departments. The factor of five is the ratio of expenditures in all of these areas to receipts in SICs 751 and 754.

[i]SIC 752 obviously does not include free commercial parking. Roughly 95% of all non-residential parking is free (Delucchi and Murphy, 1995). Therefore, we multiply energy consumption in SIC 752 by 20 to obtain energy consumption for all non-residential parking (energy consumption by residential, or non-commercial, parking is estimated separately, below), and divide by 1.9212 trillion total VMT in 1987 (FHWA, *Highway Statistics 1988*, 1989).

A calculation with a different data set yields a considerably higher result. In 1989, parking garages used a total of 5.33 kWh of electricity and 36.5 SCF of natural gas per square foot (Energy Information Administration, *Energy End-Use Intensities in Commercial Buildings*, 1994). Assuming 50 million spaces in parking garages, with a total floor area of 320 ft^2 per parking space (Delucchi and Murphy, 1995), and 2.1 trillion VMT in 1989 (FWHA, *Highway Statistics 1990*, 1991), the result is 0.04 kWh / VMT and 0.28 SCF / VMT -- for parking garages alone.

[j]Our energy-use measure is all energy associated with motor-vehicle repair in 1987, and not already included in SIC 55 (under motor vehicle dealers and service stations), divided by all 1.9212 trillion total VMT in 1987 (FHWA, *Highway Statistics 1988*, 1989). The Census data for SIC 753 in Table 9 do not cover *all* of this relevant energy use, because some motor vehicles are repaired by “in-house” repair shops at businesses, and some are repaired by households. We estimate energy use at home garages separately. That leaves energy use by repair activities done outside of SIC 75, SIC 55 and the home. On the basis of data in Delucchi

(1995c), we estimate that this "in-house" repair work not covered in SICs 75 or 55 is 10% of the amount done in SIC 75.

(Also, we assume that all of the business in SIC 75 is related to motor-vehicle use.)

[k]In 1990, households in the U.S. consumed 1.4 quads of electricity for lighting and appliances other than refrigerators, air conditioners, and water heaters (EIA, *Household Energy Consumption and Expenditures 1990*, 1993). We assume that on average a residential parking space occupies 10% of the total floor space of a house, and uses one-quarter as much electricity for lighting and appliances per square foot as does the whole house. We then assign 80% of the electricity use in these spaces to motor vehicles, and 20% to other uses such as storage and hobbies. Finally, we assume that residential (non-commercial) parking spaces are not heated, and hence do not consume natural gas or fuel oil. We divide the resulting electricity consumption by total VMT in 1990 (FHWA, *Highway Statistics 1991*, 1992).

An alternative calculation yields a comparable estimate. In 1989, commercial parking garages used an average 2.5 kWh per square foot for lighting (Energy Information Administration, *Energy End-Use Intensities in Commercial Buildings*, 1994). Residential parking spaces probably use much less; say, around 1.0 kWh per square foot (including electricity for garage door openers, and power tools for working on cars). Assuming 75 square feet of off-street, off-driveway, non-commercial parking per each of the 193 million passenger vehicles and light-trucks the U.S. in 1990 (FWHA, *Highway Statistics1991*, 1992), the result is 14.4 billion kWh in 1990, or 0.007 kWh / mile.

TABLE 11. CARB/EMFAC EMISSION FACTORS FOR REFORMULATED-GASOLINE AND DIESEL-FUEL VEHICLES, SUMMERTIME YEAR 2003

	LDA	LDT	Bus
NMOG exhaust[a] (g/mile)			
Incremental cold start	1.975	2.376	0
Incremental hot start	0.272	0.358	0
Stabilized running emissions	0.145	0.196	5.62
CO exhaust[a] (g/mile)			
Incremental cold start	21.790	33.740	0
Incremental hot start	4.740	6.870	0
Stabilized running emissions	2.490	3.030	25.47
NOx exhaust[a] (g/mile)			
Incremental cold start	1.490	2.250	0
Incremental hot start	0.810	1.190	0
Stabilized running emissions	0.310	0.440	19.86
NMOG evaporative[a]			
Hot soak (g / trip)	0.330	0.320	0
Diurnal (g / day)	0.530	0.540	0
Running loss (g / mile)	0.154	0.154	0
Resting loss (g / day)	0.960	0.840	0
Other emissions			
Exhaust PM[a] (g / mile)	0.010	0.010	2.45
Tire wear and brake wear PM_{10}[b] (g / mile)	0.22	0.22	0.66
N_2O (g / mile)[c]	0.050	0.050	0.02
CH_4 (fraction of exhaust NMOG)[c]	0.147	0.147	0.048
Drive cycle data and other data			
RVP of gasoline in EMFAC runs[a]	7.00	7.00	n.a.
Speed in EMFAC runs[a] (mph)	20.00	20.00	20.00
Bag-2 to Bag 1 speed correction[a] (multiplier)	0.81	0.79	n.a.
Distance of Bag-2 test (miles)[d]	3.89	3.89	n.a.
Distance of Bag-1 test (miles)[d]	3.59	3.59	n.a.
Fraction of exhaust TOG that is NMOG[e]	0.8515	0.8515	0.9573
Fraction of evaporative TOG that is NMOG[f]	1	1	n.a.

LDA = light-duty automobile; LDT = light-duty truck; TOG = total organic gases; NMOG = nonmethane organic gases; CO = carbon monoxide; NO_x = nitrogen oxides; PM = particulate matter; CH_4 = methane; N_2O = nitrous oxide.

[a]EMFAC estimated PM (not PM_{10}) emissions for catalyst-equipped LDAs and LDTs in summertime of the year 2003 (using year-2003 reformulated gasoline), with inspection and maintenance programs in place. For the final PM_{10} emission estimates, we multiply PM by the fraction that is PM_{10}. According to EPA's *Air Emissions Species Manual, Volume II* (1990), PM from gasoline vehicles is 97% PM_{10}, and PM from diesel-fuel vehicles is 100% PM_{10} (EPA *Air Emissions Species Manual, Volume II,* 1990). We assume that PM from AFVs is 97% PM_{10}.

[b]From CARB'sEMFAC7F and EPA's *Air Emissions Species Manual, Volume II* (1990). See text for relevant discussion.

[c]From DeLuchi (1991, 1993).

[d]The distances in the Federal Test Procedure.

[e]EMFAC estimates TOG, not NMOG. We analyzed ARB emissions data to determine the fraction of TOG that is NMOG.

[f]There is no methane in gasoline or diesel fuel.

TABLE 12. EMISSIONS FROM ALTERNATIVE-FUEL VEHICLES RELATIVE TO EMISSIONS FROM GASOLINE AND DIESEL-FUEL VEHICLES

	LDAs				LDTs					
	M85	LPG	CNG	E85	M85	LPG	CNG	E85	M85	LPC
NMOG exhaust[a]	1.265	0.647	0.647	0.941	1.265	0.647	0.647	0.941	1.937	0.87
Reactivity of exhaust[b]	0.43	0.58	0.19	0.73	0.43	0.58	0.19	0.73	0.43	0.5
CO exhaust[a]	0.900	0.700	0.500	0.900	0.900	0.700	0.500	0.900	1.195	0.83
NOx exhaust[a]	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.600	0.50
NMOG evaporative[a]	0.43	0.00	0.00	0.20	0.43	0.00	0.00	0.20	input mass	inpu mas
Reactivity of evaporative[c]	0.16	0.13	0.00	0.41	0.16	0.13	0.00	0.41	0.16	0.1
PM exhaust[a]	0.50	0.30	0.20	0.50	0.50	0.30	0.20	0.50	0.20	0.1
PM tire-wear[d]	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
N2O exhaust[a]	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
CH4 exhaust[a]	0.50	1.00	20.00	0.50	0.50	1.00	20.00	0.50	0.50	1.0

Notes: see next page.

LDA = light-duty automobile; LDT = light-duty truck; TOG = total organic gases; M85 = 85% methanol and 15% gasoline; LPG = liquefied petroleum gases (mainly propane); CNG = compressed natural gas; E85 = 85% ethanol and 15% gasoline; NMOG = nonmethane organic gases; CO = carbon monoxide; NO_x = nitrogen oxides; PM = particulate matter; CH_4 = methane; N_2O = nitrous oxide.

Note that SO_x emissions are calculated on the basis of the sulfur content of the fuel.

[a]From DeLuchi (1991, 1993), or information therein. The estimates in this table pertain to single-fuel, optimized alternative-fuel vehicles. There is a huge literature on emissions from AFVs relative to emissions from GVs and buses. For example, U. S. Congress (1990), Heath (1992), Sperling and DeLuchi (1993), Webb (1992), and Gushee (1992) provide summaries.

Because diesel buses do not have appreciable evaporative emissions, we have estimated evaporative emissions from alternative-fuel buses directly, rather than relative to [the practically non-existent] evaporative emissions from diesel buses.

[b]The reactivity adjustment factors (RAF) for exhaust emissions are the “maximum incremental reactivity” factors calculated with the SAPRC90 mechanism (McNair et al., 1992; CARB, 1992), with two further modifications by us. First, we have increased the original factors for LPG, methanol, and ethanol by 10%, to account for an apparent underestimation of ozone-forming potential during extremely stagnant conditions (McNair et al., 1994). CARB in fact has officially increased the RAF for methanol by 10% on account of this. McNair et al. (1994) suggest that the same should be done for LPG, and we assume further that ethanol should be treated similarly to methanol (McNair et al. do not consider ethanol). It appears that the RAF for CNG need not be increased.

Second, we have increased all of the original RAFs to account for the lower reactivity of reformulated gasoline compared with the reactivity of the current industry-average gasoline with respect to which the original RAFs have been developed. That is, we divide the original RAFs (estimated relative to current industry-average gasoline) by the RAF for reformulated gasoline (estimated relative to the same current industry-average gasoline) to obtain RAFs for alternative fuels relative to reformulated gasoline. We assume an RAF for reformulated gasoline of 0.95 (California Air Resources Board, March 15 1993).

Note that the RAF for ethanol was developed on the basis of very little data (CARB, 1992). However, recent tests on four variable-fuel 1992 Chevrolet Luminas adjusted to run on ethanol have resulted in a similar albeit slightly higher RAF of 0.79 (Marshall, 1994; we have increased the reported factor of 0.68 by 10% [stagnant conditions] and then by 5% [versus reformulated gasoline], as discussed above).

[c]We assume that evaporative emissions from methanol vehicles comprise methanol, that evaporative emissions from LPG vehicles comprise propane, and that evaporative emissions from ethanol vehicles comprise ethanol. We then take Carter’s (1994) most recent RAFs (maximum incremental reactivity) for these compounds, and divide by our estimated 0.95 RAF for reformulated gasoline (see note b above).

[d]We assume that all vehicles will wear out tires at approximately the same rate.

TABLE 13. TOXIC AIR POLLUTANTS AS A FRACTION OF NMOG EMISSIONS FROM VEHICLES

	Gasoline exhaust[a]	M85[a]	LPG[b]	CNG[b]	E85[a]	Diesel[c]	Gasoline evaporation[d]
Benzene	0.039	0.010	0.001	0.001	0.006	0.011	0.030
Formaldehyde	0.017	0.053	0.041	0.014	0.018	0.029	0.000
Acetaldehyde	0.005	0.002	0.007	0.005	0.077	0.008	0.000
1,3-butadiene	0.004	0.001	0.000	0.001	0.001	0.014	0.000
Ethene	0.059	0.009	0.056	0.033	0.049	0.000	0.000

ex. = exhaust; evap. = evaporative emissions.

[a]These are fractions of composite FTP emissions of non-methane organic compounds. We calculated them from an emissions data base provided by CARB (Croes, 1995). The data base contained 41 tests on 12 Phase-II reformulated-gasoline TLEVs (transitional low-emission vehicles), 14 tests on 6 M85 TLEVs, 8 tests on 2 ethanol TLEVs, and 37 tests on 9 Phase-II reformulated-gasoline LEVs. The gasoline exhaust fractions are the averages of the fractions from the LEVs and the TLEVs.

Note that the emissions profile for E85 is based on only 8 emissions tests of 2 ethanol vehicles (Croes, 1995) -- far fewer vehicles and tests than for the other fuels. Consequently, the results for E85 are relatively uncertain.

[b]These are fractions of composite FTP emissions of non-methane organic compounds. We calculated them from an emissions data base provided by CARB (Purnell, 1995). The data base contained14 tests on 6 M85 TLEVs and 8 tests on 2 ethanol TLEVs.

[c]The results of tests on two heavy-duty diesel vehicles (EPA, *Motor Vehicle-Related Air Toxics Study*, 1993)

[d]From the EPA's (*Motor Vehicle-Related Air Toxics Study*, 1993) summary of studies of the benzene fraction of diurnal and hot-soak evaporative emissions from catalyst-equipped fuel-injected vehicles using reformulated gasoline. There are no toxic evaporative emissions other than benzene.

TABLE 14. CALCULATED LDA, LDT (VAN), AND BUS EMISSION FACTORS, CORRECTED FOR LOCAL TEMPERATURE, SPEEDS, AND TRIP DISTANCES (SACRAMENTO, BASELINE TRIP) (GRAMS/MILE)

Pollutant	LIGHT DUTY AUTOMOBILES					LIGHT DUTY TRUCKS						
	Gas-oline	*M85*	*LPG*	*CNG*	*E85*	*Gas-oline*	*M85*	*LPG*	*CNG*	*E85*	*Diesel*	*M85*
NMOG exhaust[a]	0.25	0.26	0.21	0.15	0.21	0.32	0.32	0.27	0.19	0.26	4.79	9.27
NMOG evap.[b]	0.13	0.05	0.00	0.00	0.03	0.13	0.05	0.00	0.00	0.03	0.00	0.51
NMOG total RAF[c]	0.38	0.12	0.04	0.09	0.40	0.45	0.15	0.05	0.11	0.54	4.79	4.05
CO	4.76	2.64	3.77	3.16	3.04	6.39	3.84	4.79	4.22	4.31	20.13	24.06
NO_x	0.39	0.39	0.39	0.39	0.39	0.56	0.56	0.56	0.56	0.56	18.33	11.00
SO_x(d)	calculated on the basis of sulfur content					calculated on the basis of sulfur content					calculated on th	
PM10 -- exhaust[e]	0.01	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	2.45	0.48
PM10 -- tire, brake[e]	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.66	0.66
PM_{10} -- road dust[f]	2.26	2.26	2.26	2.26	2.26	2.63	2.63	2.63	2.63	2.63	16.43	16.43
PM_{10} -- total[g]	2.49	2.48	2.48	2.48	2.48	2.86	2.85	2.85	2.85	2.85	19.54	17.57
C_6H_6	0.0119	0.0032	0.0003	0.0002	0.0014	0.0163	0.0037	0.0004	0.0003	0.0017	0.0513	0.0979
HCHO	0.0045	0.0168	0.0085	0.0022	0.0042	0.0054	0.0199	0.0111	0.0028	0.0051	0.1408	0.5186
CH_3CHO	0.0013	0.0006	0.0015	0.0008	0.0180	0.0016	0.0007	0.0020	0.0010	0.0217	0.0377	0.0196
$CH_2CHCHCH_2$	0.0010	0.0002	0.0000	0.0001	0.0002	0.0013	0.0003	0.0000	0.0001	0.0003	0.0684	0.0068
CH_2CH_2	0.0155	0.0028	0.0116	0.0050	0.0114	0.0189	0.0034	0.0151	0.0064	0.0138	0.0000	0.0881
N_2O	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.02	0.02
CH_4	0.037	0.019	0.745	0.037	0.019	0.047	0.024	0.943	0.047	0.024	0.228	0.114

Notes: see next page.

LDA = light-duty automobile; LDT = light-duty truck; TOG = total organic gases; M85 = 85% methanol and 15% gasoline; LPG = liquefied petroleum gases (mainly propane); CNG = compressed natural gas; E85 = 85% ethanol and 15% gasoline; NMOG = nonmethane organic gases; CO = carbon monoxide; NO_x = nitrogen oxides; PM = particulate matter; C_6H_6 = benzene; HCHO = formaldehyde; CH_3CHO = acetaldehyde; $CH_2CHCHCH_2$ = 1,3-butadiene; CH_2CH_2 ethene; CH_4 = methane; N_2O = nitrous oxide.

See the text for an explanation of the calculation of these emission factors. As explained in the text, tailpipe emission factors for buses have been adjusted to account for the effect of any difference between the estimated fuel economy of the buses modeled here and the assumed fuel economy of the buses used to develop the EMFAC emission factors.

[a]Not adjusted for relative ozone reactivity.

[b]None of the totals shown here include diurnal emissions or resting loss emissions, because these emissions are not related to use of the vehicle -- they occur when the vehicle is idle. Also, the evaporative emissions shown here are not adjusted for ozone reactivity. Evaporative emissions from AF methanol and ethanol buses are estimated by multiplying estimated evaporative emissions from AF LDVs by the ratio of the mpg of the AFV LDV to the mpg of the AF bus.

[c]Adjusted for relative ozone reactivity.

[d]Calculated on the basis of the sulfur content of the fuel (Table 23), and the fuel efficiency of the vehicle (Table 1). We assume that all sulfur oxidizes to SO_2.

[e]Calculated from the values of Table 11. See text for further discussion. We assume that PM_{10} emissions from brake wear and tire wear are proportional to vehicle weight, and that the values of Table 11 correspond to a car with a loaded driving weight of 3200 lbs.

[f]Calculated using the EPA's emission factor formula (AP-42, 1994), and the vehicle weights of Table 1. See text for further discussion.

[g]Exhaust emissions plus tire-and-brake-wear emissions plus paved-road-dust emissions.

TABLE 15. DISTRIBUTION OF TRAVEL BY PURPOSE, TYPE OF VEHICLE, AND TYPE OF ROAD

Road type[a]	**Travel by cars and vans**		**Travel by buses**		silt loading
	direct[b]	*access*[c]	*line haul*[b]	*access*[c]	(g / m^2)[d]
Interstates, freeways, expressways	0.22	0.10	0.25	0.10	0.022
Principal arterials	0.37	0.35	0.16	0.20	0.36
Minor arterials	0.21	0.25	0.16	0.20	0.64
Collectors	0.08	0.12	0.26	0.30	0.92
Local roads	0.13	0.18	0.17	0.20	1.41
Travel-weighted silt loadings (g / m^2)[e]	0.52	0.65	0.64	0.76	

[a]Categories in the FHWA's (1993) road classification.

[b]We use FHWA (1993) data to estimate the fraction of travel on each type of road.

[c]We assume that most trips to transit stations are made entirely on local roads, collectors, and arterials.

[d]As mentioned in the text, the EPA (AP-42, 1994) summarizes 44 measurements of silt loading on local streets, collector streets, major streets and highways, and freeways and expressways. The EPA road classes correspond more or less to the FHWA's local roads, collectors, principal arterials, and interstates and freeways and expressways. However, the FHWA category "minor arterial" appears to fall between the "collector streets" and the "major streets and highways" categories of the EPA. We have assumed that the silt loading on minor arterials is half way between the silt loading on EPA-designated "collector streets" and the loading on "major streets and highways".

[e]Calculated with equation (10).

TABLE 16. ELFIN PROJECTIONS OF MARGINAL GENERATION, EFFICIENCY, AND EMISSIONS IN FOUR CALIFORNIA UTILITIES, YEAR 2003

	PG&E		LADWP[a]		SCE		SDG&E	
	Generation	*Imports*	*Generation*	*Imports*	*Generation*	*Imports*	*Generation*	*Imports*
Generation mix[b]								
San Francisco	0.929	0.071	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles	0.000	0.000	0.137	0.017	0.736	0.110	0.000	0.000
San Diego	0.000	0.000	0.000	0.000	0.000	0.000	0.908	0.092
Coal Boiler	0.002	0.200	0.000	0.430	0.005	0.439	0.000	0.463
Gas Boiler	0.892	0.000	1.000	0.296	0.586	0.307	0.203	0.338
Gas Turbine	0.024	0.000	0.000	0.000	0.068	0.000	0.005	0.000
Gas CC	0.087	0.000	0.000	0.000	0.352	0.000	0.792	0.000
Oil Boiler	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Biomass	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other	(0.028)	0.800	0.000	0.273	(0.011)	0.254	0.000	0.200
Efficiency								
Gas Boiler	0.347	n.e	0.339	n.e	0.330	n.e	0.273	n.e
Gas Turbine	0.250	n.e	n.e	n.e	0.208	n.e	n.e	n.e
Gas CC	0.455	n.e	n.e	n.e	0.397	n.e	0.484	n.e
ROG emissions *(lbs/10^6 BTU)*								
Gas Boiler	0.001	n.e	0.005	n.e	0.008	n.e	0.001	n.e
Gas Turbine	0.037	n.e	n.e	n.e	0.009	n.e	n.e	n.e
Gas CC	0.004	n.e	n.e	n.e	0.006	n.e	0.009	n.e
CO emissions *(lbs/10^6 BTU)*								
Gas Boiler	0.039	n.e	0.038	n.e	0.014	n.e	0.044	n.e
Gas Turbine	0.119	n.e	n.e	n.e	0.023	n.e	n.e	n.e
Gas CC	0.062	n.e	n.e	n.e	0.008	n.e	0.025	n.e
NO_x emissions *(lbs/10^6 BTU)*								
Gas Boiler	0.027	n.e	0.016	n.e	0.017	n.e	0.021	n.e
Gas Turbine	0.244	n.e	n.e	n.e	0.286	n.e	n.e	n.e
Gas CC	0.037	n.e	n.e	n.e	0.076	n.e	0.021	n.e

SO_x emissions *(lbs/10^6 BTU)*								
Gas Boiler	0.001	n.e	0.001	n.e	0.001	n.e	0.001	n.e
Gas Turbine	0.108	n.e	n.e	n.e	0.002	n.e	n.e	n.e
Gas CC	0.001	n.e	n.e	n.e	0.001	n.e	0.001	n.e
PM_{10} emissions *(lbs/10^6 BTU)*								
Gas Boiler	0.003	n.e	0.008	n.e	0.002	n.e	0.004	n.e
Gas Turbine	0.037	n.e	n.e	n.e	0.014	n.e	n.e	n.e
Gas CC	0.006	n.e	n.e	n.e	0.002	n.e	0.015	n.e

PG&E = Pacific Gas & Electric; LADWP = Los Angeles Department of Water and Power; SCE = Southern California Edison; SDG&E = San Diego Gas & Electric; CC = combined cycle; ROG = reactive organic gases (similar to nonmethane hydrocarbons); CO = carbon monoxide; NO_X = nitrogen oxides; SOx = sulfur oxides; PM_{10} = particulate matter of less than 10 micron diameter; n.e. = not estimated.

Source: The "Elfin" electricity model of the California Energy Commission (CEC), programmed to model the effect of a uniform 1% increase in electricity demand in 2003, compared to the Elfin base case. Of course, in reality the extra electricity demand of a new transit system will not simply bump up demand by 1% every hour, which is what Elfin modeled. For example, rail systems use more energy during peak hours than they do after the trains stop running for the night. Unfortunately, the CEC was not able to model a change in demand hour-by-hour. We note, though, that with rail systems the difference between peak and off-peak energy use might not be as large as one might expect, because nontraction energy use (e.g., for lighting stations) is independent of passenger load (and a large fraction of total energy use), and traction energy use is only weakly related to passenger load.

The data sets in the Elfin model represent typical conditions in a year. To the extent that conditions in the future are not like the "typical" conditions represented in Elfin, the Elfin output will be inaccurate. Also, the Elfin data sets include the CEC's projections of the *maximum* cost, not necessarily the most likely cost, of any additional resources required by utilities. Consequently, the Elfin output are not the CEC's official projections of capacity, emissions or fuel use.

[a]The California Energy Commission produced Elfin results for LADWP "before" the 1% increase in demand, but was unable to run the "after" scenario. In order to estimate the effects of the 1% increase in demand in LADWP, we assumed that: $LADWP_{difference}$ = $LADWP_{before}$ x $SDG\&E_{difference}$ / $SDG\&E_{before}$; that is, we scaled the LADWP before (or base case) factors by scaling factors (difference / before) from the SDG&E utility.

[b]The entries in the first three rows under "Generation mix" (San Francisco through San Diego) show the fraction of electricity consumption in each region that is supplied by in-service-area generation or imports by Utility. They total to 1.00 horizontally across all utilities. (Sacramento is not included here because the Elfin does not include the Sacramento

Municipal Utility District.) The entries in the remaining rows (coal boiler to other) show the fraction of total generation by each utility that comes from each plant type. They total to 1.00 vertically.

[c]Includes geothermal power, hydropower (including srpingtime hydro spill), wind power, and solar power.

TABLE 17. PROJECTED FUEL INPUT AND ELECTRICITY GENERATION OF U.S. UTILITY AND NON-UTILITY POWER GENERATION

	1995		2000		2005		2010	
	quads	*tWh*	*quads*	*tWh*	*quads*	*tWh*	*quads*	*tWh*
Coal Boiler[a]	n.e.	1,641.5	17.5	1,696.0	18.02	1,748.0	19.93	1,936.0
Coal FBC[a]	n.e.	0.0	0.0	0.0	0.01	1.0	0.02	2.0
Coal IGCC[a]	n.e.	0.0	0.0	0.0	0.01	1.0	0.02	2.0
Gas Boiler[b]	n.e.	209.8	2.3	204.1	2.1	185.2	1.6	149.5
Gas Turbine[b]	n.e.	28.6	0.4	34.5	0.47	40.8	0.46	40.0
Gas CC[b]	n.e.	93.6	1.6	168.4	2.64	285.0	3.00	327.4
Oil Boiler[b]	n.e.	74.9	0.8	78.1	0.84	77.9	0.66	61.7
Oil Turbine[b]	n.e.	2.8	0.1	4.4	0.08	7.1	0.07	6.2
Oil CC[b]	n.e.	1.9	0.0	3.5	0.06	6.0	0.07	7.2
Biomass[c]	n.e.	n.e.	0.50	48.4	0.68	65.9	0.87	83.6
Nuclear	n.a	n.e.	n.a.	671.0	n.a	680.0	n.a	612.0
Other[d]	n.a	n.e.	n.a	314.6	n.a	327.1	n.a	370.4
Total	n.e.	n.e.	23.22	3,223.0	24.89	3,425.0	26.69	3,598.0

Source: Energy Information Administration, *Annual Energy Outlook 1994* (1994), *Supplement to the Annual Energy Outlook 1994* (1994), and unpublished data from the EIA Office of Integrated Analysis and Forecasting (1994); data on power generation and fuel input for power generation by utility and nonutility generators. Excludes cogeneration, except as noted.

tWh = terawatt-hour (10^{12} watt-hours); quad = 10^{15} BTUs; FBC = fluidized-bed combustion; IGCC = integrated gasification combined-cycle; CC = combined cycle; n.e. = not estimated; n.a. = not applicable

[a]The EIA shows generation for the generic category "coal," and does not distinguish generating technologies. We estimate that FBC and IGCC coal technology comes on line in 2005.

[b]The EIA's *Annual Energy Outlook 1994* (1994) and *Supplement to the Annual Energy Outlook 1994* (1994) project total generation by gas-fired plants and by oil-fired plants, but do not break down the projections by type of generating technology. However the EIA's Office of Integrated Analysis and Forecasting (1994) provided us with their unpublished projections of generation by oil steam plants, gas steam plants, oil and gas dual-fuel steam plants, oil combustion turbines, gas combustion turbines, oil and gas dual-fuel combustion turbines, oil combined cycles, gas combined cycles, and oil and gas dual-fuel combined cycles. The EIA

does not state what fraction of generation by dual-fuel plants comes from gas, and what fraction comes from oil, so we must make assumptions ourselves: we assume that gas is used to generate 78% of the output of dual-fuel steam plants, 100% of the output of dual-fuel combustion turbines, and 98% of the output of dual-fuel combined-cycle plants. With these assumptions, our resultant total generation by all gas plants and total generation by all oil plants equals the EIA's (*Annual Energy Outlook 1994*, 1994) projection of total generation by gas plants and by oil plants.

The EIA's *Annual Energy Outlook 1994* (1994) and *Supplement to the Annual Energy Outlook 1994* (1994) project total consumption of coal, oil, gas, and biomass by utility and nonutility generators, but not for individual technologies. However, the EIA does project the energy efficiency of new generating technologies (EIA, *Supplement to the Annual Energy Outlook 1994*, 9194). We allocate total projected fuel consumption to individual generating technologies so that the back-calculated generation efficiencies are consistent with the EIA's efficiency projections.

[c]Biomass and wastes. Includes biomass-fueled cogeneration.

[d]All other utility and nonutility generation, including pumped storage *less* biomass-fueled cogeneration. We have subtracted biomass-fueled cogeneration so that the total matches the EIA's total projected utility and nonutility generation.

TABLE 18. PROJECTED U.S. NATIONAL AVERAGE GENERATION MIX AND EFFICIENCY

Year:	2000		2005		2010	
	mix	*efficiency*	*mix*	*efficiency*	*mix*	*efficiency*
Coal Boiler	0.526	0.331	0.510	0.331	0.538	0.331
Coal FBC	0.000	n.a.	0.000	0.371	0.001	0.379
Coal IGCC	0.000	n.a.	0.000	0.371	0.001	0.379
Gas Boiler	0.063	0.298	0.054	0.304	0.042	0.321
Gas Turbine	0.011	0.294	0.012	0.296	0.011	0.297
Gas CC	0.052	0.364	0.083	0.368	0.091	0.372
Oil Boiler	0.024	0.322	0.023	0.316	0.017	0.317
Oil Turbine	0.001	0.294	0.002	0.295	0.002	0.298
Oil CC	0.001	0.364	0.002	0.368	0.002	0.370
Biomass	0.015	0.330	0.019	0.331	0.023	0.328
Nuclear	0.208	n.a.	0.199	n.a.	0.170	n.a.
Other	0.098	n.a.	0.095	n.a.	0.103	n.a.

Source: Table 17. See the notes to that table. Excludes cogeneration, except as noted.

tWh = terawatt-hour (10^{12} watt-hours); quad = 10^{15} BTUs; FBC = fluidized-bed combustion; IGCC = integrated gasification combined-cycle; CC = combined cycle; n.a. = not applicable.

TABLE 19. CALCULATED AVERAGE GENERATION MIX FOR FIVE CALIFORNIA UTILITIES, 2003

	PG&E		SMUD		LADWP		SCE		SDG&E	
	Gener-ation	*Im-ports*[b]	*Gener-ation*	*Im-ports*[c]	*Gener-ation*	*Im-ports*[d]	*Gener-ation*	*Im-ports*[e]	*Gener-ation*	*Im-ports*[f]
Sacramento	0.000	0.000	0.555	0.445	0.000	0.000	0.000	0.000	0.000	0.000
San Francisco	0.850	0.150	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles	0.000	0.000	0.000	0.000	0.117	0.107	0.698	0.078	0.000	0.000
San Diego	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.948	0.052
Coal boiler	0.020[g]	0.200	0.000	0.200	0.446	0.450	0.191[g]	0.414	0.000	0.228
Gas boiler	0.3967	0.000[h]	0.000	0.000	0.330	0.320	0.343	0.269	0.552	0.000
Gas turbine	0.021	0.000	0.000	0.000	0.009	0.000	0.026	0.000	0.119	0.000
Gas CC	0.000	0.000	0.000	0.000	0.000	0.000	0.045	0.000	0.000	0.000
Oil boiler	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Biomass	0.060[g]	0.000	0.000	0.000	0.000	0.000	0.032[g]	0.000	0.010[i]	0.000
Nuclear	0.195	0.000	0.000	0.000	0.109	0.000	0.200	0.000	0.318	0.000
Other[j]	0.299	0.800	1.000	0.800	0.109	0.230	0.164	0.317	0.000	0.772

Source: We projected future generation on the basis of historical generation data and future capacity projections in the Biennial Electricity Report (ER) of the California Energy Commission (CEC) (1992). The CEC's ER shows actual annual generation (in Watt-hours), by fuel type and Utility, through 1991, and projects capacity (Watts) by fuel type and Utility for 1992 and later. Generation (in Watt-hours per year) is equal to capacity (in Watts) multiplied by of hours of operation per year. In essence, we calculated the number of hours that each fuel type (e.g., coal) in each Utility (e.g., PG&E) operated in 1991, and assumed that the same fuel type for the same Utility will operate the same number of hours in each future year. In order to calculate the number of hours of operation in 1991, we assumed that the actual capacity in 1991 was equal to the projected capacity in 1992. Also, because the CEC distinguishes between gas boilers and turbines and combined-cycle plants in its capacity projections but not in its historical generation figures, we in effect assumed that all gas-fired plants operate the same number of hours per year.

The entries in the first four rows (Sacramento through San Diego) show the fraction of electricity consumption in each region that is supplied by in-service-area generation or imports by Utility. They total to 1.00 horizontally across all five utilities. The entries in the remaining rows (coal boiler to other) show the fraction of total generation by each utility that comes from each plant type. They total to 1.00 vertically.

PG&E = Pacific Gas & Electric; SMUD = Sacramento Municipal Utility District; LADWP = Los Angeles Department of Water and Power; SCE = Southern California Edison; SDG&E = San Diego Gas & Electric.

[b]The ER projects capacity available to PG&E from the Pacific Northwest. We follow the suggestion of CEC staff and assume that 80% of this is hydro capacity, and 20% coal-fired capacity.

[c]The ER projects capacity available to SMUD from the Pacific Northwest and from other California Utilities. We assume that the capacity from the Pacific Northwest is 80% hydro and 20% coal, and that the capacity from other California Utilities comes from PG&E and SCE.

[d]The ER projects capacity available to LADWP from the Pacific Northwest and the Pacific Southwest. We follow the suggestion of CEC staff, and assume that the capacity from the Pacific Northwest is 80% hydro and 20% coal and that the capacity from the Pacific Southwest is 55% coal and 45% gas.

[e]The ER projects capacity available to SCE from the Pacific Northwest, the Pacific Southwest, and other California Utilities. We assume that the capacity from the Pacific Northwest is 80% hydro and 20% coal, that the capacity from the Pacific Southwest is 55% coal and 45% gas, and that the capacity from other California Utilities comes from PG&E.

[f]The ER projects capacity available to SDG&E from the Pacific Northwest, the Pacific Southwest, and Mexico. We assume that the capacity from the Pacific Northwest is 80% hydro and 20% coal, that the capacity from the Pacific Southwest is 55% coal and 45% gas, and that the capacity from Mexico is the same as that from the Pacific Southwest..

[g]The historical generation figures for 1991 distinguish biomass from coal, but the capacity projections lump biomass with coal (CEC, 1992). We have separated biomass from coal in our projections of generation by assuming that the future ratio of biomass to coal generation will be the same as it was in 1991.

[h]The ER projects that PG&E will get all of its out-of-state power from the Pacific Northwest -- which we assume will provide coal or hydro but no gas-fired capacity -- even though in 1991 PG&E got 8% of its total out-of-state imports from gas-fired plants in the Pacific Southwest (CEC, 1992). Because the actual consumption in 1991 is inconsistent with the projections, we used the actual consumption in1990, when PG&E got virtually all of its imported power from the Pacific Northwest, as the basis of our calculation of future generation given future capacity projections.

[i]In 1991, SDG&E generated 1% of its electricity from biomass, and none from coal (CEC, 1992). However, the CEC projects no coal/biomass capacity for 1993. We assumed 1% biomass-fired capacity in 1993, and reduced the CEC’s projected oil-fired capacity by 1%.

[j]Includes geothermal power, hydropower (including srpingtime hydro spill), wind power, and solar power.

TABLE 20. PROJECTED MARGINAL GENERATION MIX FOR BOSTON AND WASHINGTON, D. C., YEAR 2000

	Boston	Washington, D. C.
Coal Boiler	0.10	0.60
Coal FBC	0.00	0.00
Coal IGCC	0.00	0.00
Gas Boiler	0.16	0.06
Gas Turbine	0.08	0.08
Gas Combined Cycle	0.10	0.02
Oil Boiler	0.40	0.10
Oil Turbine	0.10	0.06
Biomass	0.02	0.02
Nuclear	0.04	0.06
Hydro, geothermal, wind, etc.	0.00	0.00

Source: As a basis for projecting the marginal generation mixes for Boston and Washington in the year 2000, we first reviewed the estimated average mixes for these cities in 1988, and then calculated average mixes for the region in the year 2000.

1). DeLuchi (1993) analyzed an EIA computer printout of electricity generation by fuel type for every utility in the U.S. in 1988, and a directory of the service areas of U.S. electric utilities, and estimated that in Boston in 1988, 89% of the electricity was from oil-fired plants, and 11% from natural-gas fired plans, and that in Washington, D. C., 88% was from coal, 12% from oil, and 1% from natural gas.

2) We used data from the EIA (*Supplement to the Annual Energy Outlook 1994*, 1994) to calculate average generation mixes in the year 2000 in the regional electricity markets surrounding Boston (New England) and Washington, D. C. (the Southeast) (Table 21). In the future regional mixes there will be less coal and oil power, and more nuclear power, than in the city mixes in 1988. Part of this is due to a projected decline in the use of oil in New England, and a projected increase in the use of natural gas in the Southeast, between 1988 and 2000 (EIA, *Supplement to the Annual Energy Outlook 1994*, 1994), and part is due to fundamental differences between the city mixes and the regional mixes.

On the basis of these estimates and considerations, and with the additional knowledge that nuclear and hydro power plants typically supply the baseload and not the margin, we projected the marginal power mixes of this table.

TABLE 21. PROJECTED AVERAGE GENERATION MIX FOR NEW ENGLAND AND THE SOUTHEAST, YEAR 2000

	New England[a]		Southeast[b]	
	generation (10^9 kWh)	*shares*	*generation (10^9 kWh)*	*shares*
Coal Boiler	16.65	0.158	332.02	0.566
Coal FBC	0.00	0.000	0.00	0.000
Coal IGCC	0.00	0.000	0.00	0.000
Gas Boiler	8.95	0.085	4.74	0.008
Gas Turbine	2.03	0.019	12.41	0.021
Gas Combined Cycle	4.10	0.039	0.12	0.000
Oil Boiler	15.92	0.151	0.40	0.001
Oil Turbine	3.05	0.029	1.38	0.002
Oil Combined Cycle	0.08	0.001	0.05	0.000
Biomass	2.06	0.019	2.06	0.004
Nuclear	41.82	0.396	197.68	0.337
Hydro, geothermal, wind, etc.	10.86	0.103	35.77	0.061
Total	**105.53**	**1.00**	**586.63**	**1.00**

Source: calculated from projections of generation and capacity in the EIA's *Supplement to the Annual Energy Outlook 1994* (1994).

[a]Maine, Vermont, New Hampshire, Massachusetts, Connecticut, and Rhode Island.

[b]Georgia, Alabama, South Carolina, North Carolina, Tennessee, Washington D. C., and parts of Mississippi, Kentucky, and Virginia.

TABLE 22. PROJECTED NATIONAL-AVERAGE EMISSIONS FROM ELECTRICITY-GENERATING PLANTS, WITH EMISSION CONTROLS, YEAR 2000 (LBS-EMISSION PER MILLION BTU INPUT)

	Coal DBPCB[a]	*Coal IGCC*[b]	*NG boiler*[a]	*NG turbine*[a]	*NG CC*[b]	*Fuel-oil boiler*[a]	*Biomass*[c]
CH_4	0.001	0.002	0.000	0.024	0.035	0.002	0.001
N_2O	0.009	0.009	0.004	0.004	0.004	0.004	0.009
NMHC	0.003	0.003	0.001	0.004	0.006	0.005	0.282
CO	0.029	0.004	0.039	0.110	0.112	0.033	0.066
NO_x(d)	0.502	0.095	0.267	0.220	0.201	0.336	0.082
SO_x(e)	0.923	0.075	0.001	0.001	0.001	0.529	0.009
PM	0.048	0.010	0.003	0.014	0.003	0.022	0.020
PM_{10}(f)	0.034	0.010	0.003	0.013	0.003	0.018	0.016
C_6H_6	0.0001	0.0001	0.0000	0.0015	0.0002	0.0050	0.0004
HCHO	0.0002	0.0002	0.0001	0.0030	0.0003	0.0021	0.0007
CH_3CHO	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	0.0003
$CH_2CHCHCH_2$	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
CH_2CH_2	0.0000	0.0000	n.e.	n.e.	n.e.	n.e.	n.e.

DBPCB = dry-bottom pulverized-coal boiler (most utility power plants are of this type); IGCC = integrated gasification combined-cycle power plant; CC = combined cycle; CH_4 = methane; N_2O = nitrous oxide; NMHC = nonmethane hydrocarbons; CO = carbon monoxide; NO_x = nitrogen oxides; NO_2 = nitrogen dioxide; SOx = sulfur oxides; PM_{10} = particulate matter with a diameter of 10 microns or less; $PM_{2.5}$ = particulate matter with a diameter of 2.5 microns or less, C_6H_6 = benzene, HCHO = formaldehyde, $CH_2CHCHCH_2$ = 1,3-butadiene, CH_2CH_2 = ethylene, n.e. = not estimated.

[a]Emission factors for CH_4 and N_2O are from DeLuchi (1993). Emission factors for NMHCs, CO, NO_x, SO_x, PM, and PM_{10} are from the EPA's AP-42 (EPA, 1994) and other sources, as documented in DeLuchi (1993). Emission factors for toxic air pollutants are from the EPA's AP-42 (1994), *Air Emissions Species Manual* (1990) and *Toxic Air Pollutant Emission Factors* (1990), and are used as follows. The *Air Emissions Species Manual* (1990) reports formaldehyde emissions from oil boilers, formaldehyde and benzene emissions from natural-gas boilers, and ethylene and benzene emissions from industrial coal boilers, as a fraction of total VOC emissions. We assume that the fractions estimated for natural-gas boilers apply to natural-gas turbines and combined-cycle plants, and that the fraction estimated for coal boilers applies to coal IGCC plants. *Toxic Air Pollutant Emission Factors* (1990) reports a formaldehyde emission factor for coal boilers; we assume that this factor applies to coal-fired IGCC plants as well.. Finally, AP-42 (1994) reports emission factors for benzene, formaldehyde, and acetaldehyde

from wood-waste combustion. We assume that these factors apply to biomass power generation.

[b]Emission factors for CH_4, N_2O, NMHCs, CO, and NO_x are from DeLuchi (1993). The PM and PM_{10} factors are our estimates.

[c]The NMHC, CO, and NO_x emission factors are calculated from emissions data reported for a fluidized-bed power plant in Fresno, California (Ismail and Quick, 1992). The CH_4 and PM emission factors are from the EPA (1994), assuming an electrostatic precipitator to control PM. The N_2O emission factor is our estimate.

[d]As NO_2.

[e]SO_x emissions are calculated on the basis of the sulfur content of the fuel (Table 23). The SO_x emission factor for fuel-oil combustion includes emissions of SO_3 as well as of SO_2.

[f]The fraction of PM that is PM_{10} depends on the type of control technology used. Data in EPA's AP-42 (1992) indicate that 70% of the PM from coal boilers, 95% from natural-gas boilers, and 80% from oil and wood boilers, is PM_{10}.

TABLE 23. CHARACTERISTICS OF FUELS.

	Higher heating values				Density		Carbon	Sulfur
	Value	*Units*	*Value*	*Units*	*Value*	*Units*	*weight percent*	*weight percent*
Residual fuel	0.1497	10^6 BTU / gal	6.287	10^6 BTU / bbl	3575	g / gal	85.8	0.9900
Diesel fuel	0.1387	10^6 BTU / gal	5.825	10^6 BTU / bbl	3192	g / gal	85.8	0.05
Gasoline	0.1251	10^6 BTU / gal	5.253	10^6 BTU / bbl	2791	g / gal	86.6	0.004
Methanol	0.0645	10^6 BTU / gal	46446	g / 10^6 BTU	2996	g / gal	37.5	0.0007
Ethanol	0.0846	10^6 BTU / gal	35319	g / 10^6 BTU	2988	g / gal	52.2	0.0007
Coal			20.923	10^6 BTU / ton			60.0	0.9900
Hydrogen	7470	g / 10^6 BTU	338	BTU / SCF			0.0	0.0000
Natural gas	19768	g / 10^6 BTU	1032	BTU / SCF			0.0	0.0007
Dried wood			8350	BTU / lb				

Source: DeLuchi (1993), except sulfur content of gasoline, which is from Fletcher and Donohue (1992).

TABLE 24. EMISSIONS FROM THE USE OF ELECTRICITY IN CALIFORNIA (G/KWH-DELIVERED)

	Sacramento	San Francisco	Los Angeles	San Diego
NMHC	0.0014	0.0111	0.0317	0.0241
CO	0.0134	0.1950	0.0907	0.1263
NO_X	0.2321	0.2377	0.4561	0.2393
SO_X	0.4267	0.1736	0.2884	0.2080
PM_{10}	0.0155	0.0234	0.0283	0.0494
C_6H_6	0.0001	0.0004	0.0009	0.0005
HCHO	0.0001	0.0009	0.0018	0.0010
CH_3CHO	0.0000	0.0000	0.0000	0.0000
$CH_2CHCHCH_2$	0.0000	0.0000	0.0000	0.0000
CH_2CH_2	0.0000	0.0000	0.0000	0.0000
N_2O	0.0041	0.0209	0.0226	0.0185
CH_4	0.0007	0.0150	0.0480	0.0859
Fuelcycle greenhouse gases	108.80	648.07	700.68	577.20

NMHC = non-methane hydrocarbons, CO = carbon monoxide, NO_X = nitrogen oxides, SO_X = sulfur oxides, PM = particulate matter, PM_{10} = particulate matter with a diameter of 10 microns or less, $PM_{2.5}$ = particulate matter with a diameter of 2.5 microns or less, C_6H_6 = benzene, HCHO = formaldehyde, $CH_2ChCHCH_2$ = 1,3-butadiene, CH_2CH_2 = ethylene, N_2O = nitrous oxide, CH_4 = methane.

The emission factors are calculated from several data sets, as summarized below:

	Sacramento	San Francisco	Los Angeles	San Diego
Generation mix	average mix in 2003 (Table 19)	marginal mix in 2003 (Table 16)		
Efficiency and NMHC, CO, NO_X, SO_X, and PM_{10} emission factors, gas-fired power plants	not applicable	Elfin projections of marginal plant efficiency and emission factors for the year 2003 (Table 16)		
Efficiency and emission factors, all other pollutants, power plants	Our projections of U.S. national average efficiency (Table 18).and emission factors (Table 22), year 2000			

TABLE 25. EMISSIONS OF CRITERIA POLLUTANTS FROM PETROLEUM REFINERIES IN CALIFORNIA (GRAMS/GALLON OF OUTPUT)

	TOG	ROG	CO	NO_X	SO_X	PM	PM_{10}
Gasoline							
fuel use[a]	0.087	0.037	0.276	0.932	0.161	0.085	0.083
electricity use[b]	0.007	0.007	0.035	0.267	0.270	0.011	0.005
other process areas[c]	0.800	0.621	0.092	0.193	0.611	0.112	0.061
Total	*0.894*	*0.664*	*0.403*	*1.393*	*1.042*	*0.207*	*0.150*
Diesel fuel							
fuel use[a]	0.034	0.014	0.109	0.367	0.063	0.033	0.033
electricity use[b]	0.003	0.003	0.014	0.105	0.106	0.004	0.002
other process areas[c]	0.582	0.452	0.092	0.193	0.724	0.112	0.061
Total	*0.619*	*0.469*	*0.214*	*0.665*	*0.894*	*0.149*	*0.096*
Residual fuel oil							
fuel use[a]	0.027	0.012	0.087	0.292	0.051	0.027	0.026
electricity use[b]	0.002	0.002	0.011	0.084	0.085	0.003	0.002
other process areas[c]	0.386	0.300	0.092	0.193	0.055	0.110	0.060
Total	*0.415*	*0.313*	*0.189*	*0.569*	*0.191*	*0.140*	*0.088*

TOG = total organic gases; ROG = reactive organic gases; CO = carbon monoxide; NO_X = nitrogen oxides; SO_X = sulfur oxides; PM = particulate matter; PM_{10} = particulate matter with a diameter of 10 microns or less.

[a]Gram / gallon emissions from the use of refinery fuel are calculated with the following equation:

$$E_{fip} = \frac{T_{fi} \times C_{fi} \times F_p \times 365 \times 2000 \times 453.6}{O_p \times 42}$$

where:

Ef_{ip} = gram emissions of pollutant i from refinery fuel used to produce a gallon of product p

T_{fi} = emissions of pollutant i from the use of fuel at refineries in California in 1989 (tons / day; CARB, *Emission Inventory 1989*, 1991)

C_{fi} = projected emission control factor for boilers (g / gallon emissions of pollutant i in 2000 divided by g / gallon emissions of pollutant i in 1989 (1.0 for TOG, ROG, and CO; 0.75 for NO_X, SO_X, and PM)

F_p = BTUs of refinery energy used to make product p in the year 2000 divided by total BTUs of refinery energy consumed in 1991 (0.691 for gasoline, 0.148 for distillates, and 0.041 for residual fuel; calculated from data on gallon output of all products from California refineries [EIA, data transmittal, 1993] and the amount of energy required to make a gallon of each product [DeLuchi et al., 1992].

O_p = Output of product p from California refineries, 1991 (barrels; EIA, data transmittal, 1993; we use 1991 rather than 1989 data to match with the 1991 data on electricity use by California refineries*)*.

365 = days / year

2000 = lbs / ton

453.6 = grams / lb

42 = gallons / barrels

[b]Gram / gallon emissions from the use of purchased electricity are calculated with the following equation:

$$E_{eip} = \frac{\left(G_{i-LA} \times S_{LA} + G_{i-SF} \times \left(1 - S_{LA}\right)\right) \times K \times F_p \times 2000}{O_p \times 42}$$

where:

E_{eip} = gram emissions of pollutant i from electricity purchased to produce a gallon of product p

$G_{i\text{-}LA}$ = g / kWh emissions of pollutant i from electricity plants supplying Los Angeles (Table 24)

S_{LA} = Refining capacity in Los Angeles area divided by refining capacity in state at the beginning of 1991 (0.608; calculated from data in the EIA's *Petroleum Supply Annual 1990*, 1991; we assume that the rest of the capacity is in the San Francisco area)

$G_{i\text{-}SF}$ = g / kWh emissions of pollutant i from electricity plants supplying San Francisco (Table 24)

K = kWh of electricity bought by California refineries in 1991 (EIA, data transmittal, 1993; data for 1989 are not available; we assume that the same amount was bought in 1989)

F_p = BTUs of refinery energy used to make product p in the year 2000 divided by total BTUs of refinery energy consumed in 1991 (0.691 for gasoline, 0.148 for distillates, and 0.041 for residual fuel; calculated from data on gallon output of all products from California refineries [EIA, data transmittal, 1993] and the amount of energy required to make a gallon of each product [DeLuchi et al., 1992].

O_p = Output of product p from California refineries, 1991 (barrels; EIA, data transmittal, 1993; we use 1991 rather than 1989 data to match with the 1991 data on electricity use by California refineries*)*.

42 = gallons / barrels

[c]Gram / gallon emissions from process areas at refineries are calculated with the following equation:

$$E_{aip} = \frac{T_{ai} \times C_{ai} \times A_p \times 365 \times 2000 \times 453.6}{O_p \times 42}$$

where:

E_{aip} = gram emissions of pollutant i from process areas used to produce a gallon of product p

T_{ai} = emissions of pollutant i from process areas at refineries in California in 1989 (tons / day; CARB, *Emission Inventory 1989*, 1991)

C_{ai} = projected emission control factor for process areas (g / gallon emissions of pollutant i in 2000 divided by g / gallon emissions of pollutant i in 1989 (0.8 for TOG and ROG, 1.0 for CO and NO_X, and 0.9 for SO_X, and PM)

A_p = fraction of process-area emissions of pollutant i attributable to product p (DeLuchi et al., 1992)

O_p = Output of product p from California refineries, 1991 (barrels; EIA, data transmittal, 1993; we use 1991 rather than 1989 data to match with the 1991 data on electricity use by California refineries).

365 = days / year

2000 = lbs / ton

453.6 = grams / lb

42 = gallons / barrels

TABLE 26. EMISSIONS OF TOXIC AIR POLLUTANTS FROM CALIFORNIA PETROLEUM REFINERIES (G/GALLON-OUTPUT)

	C_6H_6	HCHO	CH_3CHO	$CH_2CH\text{-}CHCH_2$	CH_2CH_2
Gasoline	0.0085	0.0077	0.0059	0.0069	0.0056
Diesel fuel	0.0043	0.0037	0.0024	0.0031	0.0022
Residual fuel oil	0.0032	0.0028	0.0019	0.0024	0.0018

Emissions of each toxic air pollutant are calculated as:

$$Et = \frac{Yt}{Yv} \times Ct \times (Vf + Vp) + Pt$$

where:

Et = Per-unit emissions of toxic air pollutant (grams / gallon)
Yt = Emissions of toxic air pollutant in SIC 2911 in 1989 (lbs / year; Table 12)
Yv = Emissions of volatile organic compounds in SIC 2911 in 1989 (lbs / year; CARB, *Emission Inventory 1989*, 1991)
Ct = Control factor for toxic pollutants specifically, on top of control of VOCs generally (assumed to be unity; i.e., no additional control)
Vf = Unit emissions (g / gal) of VOCs from fuel combustion (Table 25)
Vp = Unit emissions (g / gal) of VOCs from process areas (Table 25)
Pt = g / gallon emissions of toxic air pollutants from the generation of electricity bought by refineries

TABLE 27. EMISSIONS FROM THE PRODUCTION OF METHANOL AND ETHANOL ($GRAMS/10^6$ BTU OF OUTPUT)

Fuel--> *Feedstock->*	**MeOH** *mix*[a]	**EtOH** *mix*[a]	**MeOH** *NG*	**MeOH** *coal*	**MeOH** *wood*	**EtOH** *corn & coal*[c]	**EtOH** *corn & biomass*[b]	**EtOH** *wood*
NMHC	25.70	233.78	0.45	149.94	69.12	289.97	334.89	9.00
CO	8.22	14.29	6.00	12.96	16.16	4.62	10.65	53.00
NO_X	41.75	70.06	45.00	50.04	20.00	80.08	13.14	30.00
SO_X	5.35	118.41	0.15	50.00	1.60	147.01	1.42	4.00
TSP	n.e.	n.e.	0.15	10.00	10.00	15.67	11.59	20.00
PM_{10}(c)	1.98	12.40	0.14	7.50	7.50	11.76	8.69	15.00

MeOH = methanol; EtOH = ethanol; NG = natural gas; NMHC = nonmethane hydrocarbons; CO = carbon monoxide; NO_X = nitrogen oxides; SO_X = sulfur oxides; TSP = total suspended particulates; USDOE = U.S. Department of Energy; n.e. = not estimated.

Each g / gallon emission factor is calculated as:

$$G = \left(Ef \times C + \frac{P}{293.1} \times Ep \right)$$

where:

G = gram / gallon emission factor

Ef = emission factor in grams / 10^6-BTU fuel input (from USDOE, 1983; USDOE, 1988; Sperling , 1988; Intech, 1990; Heath, 1991; DeLuchi, 1991, 1993; Ecotraffic AB, 1992; Ismail and Quick, 1991; National Renewable Energy Laboratory, 1992; Tellus Institute, 1993; Darrow, 1994; EPA, 1994)

C = Conversion efficiency BTUs-input feedstock / BTUs-output product (NG / methanol, 1.5; coal / methanol, 1.8; wood / methanol, 1.6; coal / corn-ethanol, 0.53; biomass / corn-ethanol, 0.53; wood / ethanol, 2.35; see DeLuchi, 1993)

P = purchased power in BTUs-electricity / BTU-product (NG / methanol, 0.003; coal / methanol, 0; wood / methanol, 0.03; coal / corn-ethanol, 0.05; biomass / corn-ethanol, 0.05; wood / ethanol, -0.08; see DeLuchi, 1993)

293.1 = kWh per 10^6 BTUs

Ep = emissions from electricity generation in grams / kWh (generic out-of-state emission factors)

Note that the emission factors for NMHCs, CO, and NO_X are the same as the ones used in the greenhouse-gas analysis.

[a]Assuming the mix of feedstocks indicated in note b of Table 2.

[b]We estimated total emissions from the ethanol facility, and then allocated 67% of the total to fuel ethanol (DeLuchi, 1993). The remaining 33% is allocated to other products of the ethanol facility.)

[c]We assume that PM_{10} is 95% of TSP from NG-to-methanol plants and 75% of TSP from all other plants.

TABLE 28. EVAPORATIVE EMISSIONS FROM FUEL STORAGE, TRANSFER, DISTRIBUTION, AND DISPENSING (G/GALLON)

	Sacramento	San Francisco	Los Angeles	San Diego
Refueling emissions	3.48	2.06	2.31	2.37
Refueling spillage emissions	0.219	0.219	0.219	0.219
Other upstream emissions, excluding refineries	3.2	3.2	3.2	3.2
Total emissions, for gasoline	*6.90*	*5.48*	*5.72*	*5.78*
Total, for methanol	1.79	1.43	1.49	1.50
Total, for ethanol	1.10	0.88	0.92	0.93

Gasoline-cycle emissions are calculated as a function of temperatures and gasoline RVP, using equations from DeLuchi et al. (1992). We assume an RVP of 7.0 for gasoline (the value used in the EMFAC model), and the following temperatures:

	Sacramento	San Francisco	Los Angeles	San Diego
Average daily high temperature (July)	93.2	71.6	75.3	76.2
Average daily low temperature (July)	58.1	53.9	62.8	65.7
Temperature of dispensed fuel	79.2	60.9	64.0	64.8
Temperature of fuel in tank	88.5	68.0	71.5	72.4

The average high and low temperatures are from the Bureau of the Census, *Statistical Abstract of the United States* (1992).

We follow DeLuchi (1991) and assume that methanol-cycle emissions are 26% of gasoline cycle emissions, and ethanol-cycle emissions 16%.

TABLE 29. EMISSION FACTORS FOR NATURAL GAS AND DIESEL-FUEL USE BY BUILDINGS AND FUEL USE BY SERVICE VEHICLES

	Buildings[a]		Service vehicles[b]	
Pollutant	Natural gas *(g/1000 SCF)*	Fuel oil *(g/gallon)*	Diesel fuel *(g/gallon)*	Gasoline *(g/gallon)*
NMVOCs, vehicles	n.a.	n.a.	10.17	13.03[d]
NMOVCs, upstream	n.e	n.e.	0.00	4.00
NMOVCs, total	*3.30[c]*	*0.32*	*10.17*	*9.03*
CO	18.16	2.27	44.60	74.63
NO_x	42.68	8.17	35.67	7.65
SO_2[(e)]	0.29	70.79	2.87	0.22
PM_{10} exhaust	2.54	0.61	2.98	0.16
PM_{10} tire, brakewear	n.a.	n.a.	7.30	8.45
PM_{10} road dust	n.a.	n.a.	118.56	49.28
PM_{10}[(f)] total	*2.54*	*0.61*	*128.84*	*57.89*
C_6H_6	2.339	n.e.	0.00	0.46
HCHO	2.339	n.e.	0.87	0.09
CH_3CHO	2.339	n.e.	0.29	0.06
$CH_2CHCHCH_2$	2.339	n.e.	0.00	0.02
CH_2CH_2	2.339	n.e.	0.00	0.56
N_2O	2.063[g]	n.e.	0.06	1.00
CH_4	1.70[c]	0.81	0.48	0.68
GHGs from end use[h]	56,078	11,295	10,240	8,742
GHGs upstream[i]	9,809	2,070	2,047	2,784
Total GHGs	*65,887*	*13,365*	*12,287*	*11,525*

n.e. = not estimated; GHGs = greenhouse gases.

[a]Emission factors for NMVOCs, CO, NO_x, PM, and PM_{10} are EPA (*Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* , 1994) factors for uncontrolled residential furnaces. Factors for toxic air pollutants are those used here for natural-gas-fired utility boilers (Table 22), converted to g / 1000-SCF.

[b]Emissions from the gasoline and diesel service and administrative vehicles used by transit systems are calculated in the same way as are the emissions from all of the other passenger cars and vans and buses considered in this analysis (see the text for details, and for example

the results of Table 14). (We assume national average temperatures and trip characteristics for the service vehicles here.) They include evaporative emissions, and account for emissions from cold starts and hot starts. Emissions of toxic air pollutants are calculated as a fraction of NMVOC exhaust emissions from diesel vehicles (data of Table 13). Gram / mile emission factors are converted to the g / gal factors of this table by multiplying by miles / gallon (mpg). We assume 7 mpg for diesel vehicles, and 20 mpg for gasoline vehicles (the average fuel economy of vehicles in large Federal fleets, according to the General Services Administration, 1994?). We use g / gal factors in this table, rather than g / mile factors, because the reported activity data are gallons of fuel consumed, not miles of travel.

[c]Emission factors for uncontrolled commercial boilers (EPA, AP-42, 1994).

[d]Includes our estimate of 0.06 g / mile resting and diurnal losses: 2 grams / day (from EMFAC7F) x 365 days / year divided by an assumed13,000 miles / year (average yearly travel of vehicles in large Federal fleets, according to the General Services Administration, 1994?).

[e]SO_2 emissions are calculated on the basis of the sulfur content of the fuel (Table 23), on the assumption that all fuel sulfur oxidizes to SO_2.

[f]The PM_{10} emission factors for natural gas and fuel oil combustion are the average of "filterable PM" and "condensible PM". According to EPA, all PM from natural-gas combustion is $PM_{1.0}$ or less.

The EPA (AP-42, 1994) does not show the distribution of the size of PM emissions from residential furnaces. However, it does show the size distribution of PM emissions from commercial fuel-oil boilers. We assume that this distribution applies to PM emissions from residential heaters.

[g]We assume the same emission rate as from natural-gas-fired utility boilers (Table 22; factors converted to g / 1000-SCF). N2O NG

[h]Emissions from motor vehicles are calculated by the equation below. Emissions from natural gas and oil heaters are calculated with similar equations.

$$G = E_{NMOG} \times C_{NMOG} \times (G_{NMOG} - 3.667) + E_{CO} \times (G_{CO} - 0.429 \times 3.667) +$$
$$E_{CH4} \times (G_{CH4} - 0.75 \times 3.667) + E_{NOx} \times G_{NOx} + E_{N2O} \times G_{N2O} + C \times D \times 3.667$$

Where:

G = CO_2-equivalent emissions from gasoline or diesel vehicles (g / 10^6-BTU)

E_{NMOG} = emissions of NMOG from vehicles (g / 10^6-BTU; this table)

C_{NMOG} = carbon fraction of NMOG emissions from gasoline or diesel-fuel vehicles (0.85 for gasoline, 0.86 for diesel fuel; DeLuchi, 1993)

G_{NMOG} = global warming potential of NMOG emissions (Table 34)

3.667 = ratio of mass of CO_2 to mass of C

E_{CO} = emissions of CO from vehicles (g / mile; this table)

G_{CO} = global warming potential of CO emissions (Table 34)
0.429 = carbon fraction of CO
E_{CH4} = emissions of CH_4 from vehicles (g / mile; this table)
G_{CH4} = global warming potential of CH_4 emissions (Table 34)
0.75 = carbon fraction of CH_4
E_{NOx} = emissions of NO_x from vehicles (g / mile; this table)
G_{NOx} = global warming potential of NO_x emissions (Table 34)
E_{N2O} = emissions of N_2O from vehicles (g / mile; this table)
G_{N2O} = global warming potential of N_2O emissions (Table 34)
C = carbon fraction of reformulated gasoline or diesel fuel (Table 23)
D = energy content of reformulated gasoline or diesel fuel (g / gal, Table 23)

[i]These are the upstream greenhouse-gas emission factors of Table 31, multiplied by 10^6-BTU / gal.

TABLE 30. EMISSION OF TOXIC AIR POLLUTANTS IN CALIFORNIA IN 1989 (LBS)

	Toxic ID number -->	1110	1210	50000	67561	71432	75070	106990
SIC	Industry	Gas Vapors	Xylenes	Formal-dehyde	Methanol	Benzene	Acetal-dehyde	1-3 Butadien
1311	Crude petroleum & natural gas	10,101	115,787	247,130	38,583	231,460	22,430	2,699
1381	Drilling & oil & gas wells		21	427	431	64	16	
1382	Oil/gas exploration services			1,396		141		
1389	Oil/gas field services, n.e.c.	3,503	96	188		568		
2911	Petroleum refining	3,439,271	956,819	147,825	12,805	199,829	19,486	87,748
3711	Motor vehicle & car bodies	934	336,348	874	6,774	13		
3713	Truck and bus bodies		169,130	1,130	17,000	21		
3714	MV parts/accessories		59	980		0	5,591	
3715	Truck trailers		43,495		55			
3716	motor-home manufacturing	1,301	5,518		3,463			
4491	Marine cargo handling	179						
4911	Electric services	3,627	16,395	966,501		54,215	2,080	1,323
5171	Petrol bulk stations/terminals	3,160,208	44,278	45	6,696	26,630	1	
5172	Petrol products, n.e.c.	74,295	1,076		841	799		
5511	New & used car dealers	34	16,746			0		
5521	Used car dealers		86					
5541	Gasoline services stations	7,289	99			93		
7531	Top & body repair shops		8,479	0		31		
7532	Top & body repair/paint shops	172	90,615	0	656	14		
7533	Auto exhaust-system repair shops		1,066		278			
7534	Tire retreading & repair shops			1	4,355	270		
7535	Paints shops		1,029			0		
7538	General Auto Repair shops		502			0		
7539	Auto Repair shops, n.e.c.		117			2		
7542	Car washes			3		1		

Notes: see next page.

Source: The Special Pollutants Emission Inventory Section of the California Air Resources Board (1993) provided us with estimates of emissions of the toxics shown here from the largest emitters in each of the SICs shown here. (The largest emitters were those that emitted more than 25 tons per year of criteria pollutants VOCs, CO, NO_X, SO_X, or PM, or else were on the toxics emissions inventory list of an air-quality management district.)

SIC = Standard Industrial Classification of the U.S. Department of Commerce; n.e.c. = not elsewhere classified.

TABLE 31. GREENHOUSE-GAS EMISSION FACTORS, GRAMS CO_2-EQUIVALENT EMISSIONS FROM FUEL PRODUCTION AND TRANSPORT, PER MILLION BTU OF ENERGY DELIVERED TO END USERS (EXCEPT AS NOTED)

Coal	6,341
Reformulated gasoline	22,802
Conventional gasoline	20,338
Low-sulfur diesel	14,756
Residual fuel oil	13,828
Refinery gas	5,497
Petroleum coke	8,116
Natural gas for heat, CNG[a]	9,509
Nuclear power[b]	13,151
Methanol from natural gas	35,884
Methanol from coal	122,708
Methanol from wood	21,994
Ethanol from corn	118,548
Ethanol from wood[c]	(924)
Synthetic natural gas from wood	14,170
Hydrogen from solar power	100
LPG from a mix of NG and oil[d]	9,992
LPG from natural-gas liquids	7,824
LPG from petroleum	13,439
Wood for power production	5,521

Source: updated version of model documented in DeLuchi (1991, 1993).

[a]Emissions from the generation of electricity used to compress natural gas are calculated separately (as emissions from activities at service stations) and included in the final totals.

[b]Units are grams of CO_2 equivalents per million BTU of power generated.

[c]Negative value is due to emissions credit from the sale of excess power generated by burning portions of feedstock not converted to fuel.

[d]U.S.-average weighted mix of LPG from natural gas and LPG from petroleum.

TABLE 32. ENERGY USE BY REFINERIES IN CALIFORNIA AND NATIONALLY

	California 1991[a]		USA 1991[b]		Calif. 2000[c]
	Units	*Energy %*	*Units*	*Energy %*	*Energy %*
Crude oil (10^3 barrels)	0	0.00	0	0.00	0.00
Diesel fuel (10^3 barrels)	59	0.07	445	0.09	0.00
Residual oil (10^3 barrels)	413	0.56	10597	2.31	0.40
LPG (10^3 barrels)	4380	3.64	8105	1.09	3.00
Natural gas (10^3 cubic feet)	79360	17.61	698875	25.04	25.00
Refinery gas (10^3 barrels)	42308	54.60	230987	48.15	49.00
Marketable coke (10^3 barrels)	1810	2.35	3113	0.65	2.00
Petroleum coke (10^3 barrels)	10318	13.37	77503	16.22	13.00
Coal (10^3 short tons)	0	0.00	150	0.11	0.10
Electricity (10^6) kWh	5278	3.87	32858	3.89	4.00
Steam (10^6) pounds	13502	3.49	46476	1.94	3.50
H_2 (10^3 cubic feet)	0	0.00	24	0.00	0.00
Oils and other (10^3 barrels)	355	0.44	2474	0.50	0.00
Total process energy (10^{15} BTU)	**0.46**	**100.00**	**2.88**	**100.00**	**100.00**
Process energy/product energy[d]	**0.112**		**0.096**		**0.094**

[a]From unpublished state-level data provided by the EIA's Petroleum Supply Division (EIA, 1993).

[b]EIA, *Petroleum Supply Annual 1991* (1992).

[c]Our assumption, on the basis of the data in this Table and in DeLuchi (1993).

[d]Equal to the total amount of process energy (previous line) divided by the energy content of all of the products of the refinery.

TABLE 33. REFINERY RECEIPTS OF CRUDE OIL BY METHOD OF TRANSPORT, CALIFORNIA AND U.S., 1991

	USA[a]		**California**[b]	
	10^3 barrels	*Percent*	*10^3 barrels*	*Percent*
Pipeline				
Domestic	1,937,272	39%	283,010	41%
Foreign	803,511	16%	0	0%
Tanker				
Domestic	625,023	13%	348,407	51%
Foreign	1,369,021	28%	28,386	4%
Barge				
Domestic	111,900	2%	4,227	1%
Foreign	37,162	1%	1,230	0%
Tank cars				
Domestic	19,047	0%	11,799	2%
Foreign	0	0%	0	0%
Trucks				
Domestic	67,198	1%	7,536	1%
Foreign	0	0%	0	0%
Total				
Domestic	2,760,440	56%	654,979	96%
Foreign	2,209,694	44%	29,616	4%
Grand total	**4,970,134**	**100%**	**684,595**	**100%**

[a]EIA, *Petroleum Supply Annual 1991* (1992).

[b]From unpublished state-level data provided by the EIA's Petroleum Supply Division (EIA, 1993).

TABLE 34. GLOBAL WARMING POTENTIALS (GWPS) OF NON-CO_2 GREENHOUSE GASES, 100-YEAR TIME HORIZON

CH_4	N_2O	CO	NMHC	NO_2
21	270	2	5[a]	4[b]

Source: Delucchi (1995d), on the basis of analyses by Intergovernmental Panel on Climate Change (1992), Martin and Michaelis (1992), and other sources.

[a]Our GWP for NMHCs applies to the carbon mass of the NMHCs, not to the total mass of the NMHCs.

[b]This is the sum of a GWP of 2 due to ozone production (as estimated by Martin and Michaelis, 1992), and a GWP of 2 due to N_2O emissions from deposition of atmospheric nitrogen. The latter is our own estimate (see Delucchi, 1995d, for details).

TABLE 35. FRACTIONAL DISTRIBUTION OF MODES OF ACCESS TO BUS OR RAIL TRANSIT: GREATER SAN FRANCISCO BAY AREA (METROPOLITAN TRANSPORTATION COMMISSION REGION)

	Line-haul transit					
Mode of access to transit	*Local bus*	*Intercity bus*	*School bus*	*Light rail*	*Heavy rail*[a]	*Comm. rail*[b]
Walk	0.914	0.692	0.912	0.667	0.639	0.700
Drive alone	0.037	0.154	0.015	0.333	0.111	0.200
Car passenger	0.025	0.154	0.059	0.000	0.083	0.000
Bicycle	0.000	0.000	0.000	0.000	0.000	0.000
Local bus	0.012	0.000	0.000	0.000	0.000	0.000
Intercity bus	0.000	0.000	0.000	0.000	0.000	0.000
School bus	0.012	0.000	0.000	0.000	0.000	0.000
Light rail	0.000	0.000	0.000	0.000	0.000	0.000
Heavy rail[a]	0.000	0.000	0.000	0.000	0.056	0.100
Commuter rail[b]	0.000	0.000	0.000	0.000	0.028	0.000
Dial-a-ride	0.000	0.000	0.000	0.000	0.028	0.000
Other method	0.000	0.000	0.015	0.000	0.056	0.000
Transit trips in survey[c]	**81**	**13**	**68**	**9**	**36**	**10**
All transit/all trips[d]	*0.015*	*0.002*	*0.012*	*0.002*	*0.007*	*0.002*

Source: our analysis of the primary data from the 1991 statewide travel survey conducted by the California Department of Transportation (1993). n.a. = not applicable (no trips reported by that mode).

[a]BART, in the San Francisco Bay Area, was the only heavy-rail system in operation in California at the time of the 1991 survey.

[b]Caltrain, in the San Francisco Bay Area, was the only commuter-rail system in operation in California at the time of the 1991 survey.

[c]This is the actual number of daily trips by transit, *among those surveyed*. We have not scaled the results to represent total trips by transit for the entire population of the whole region. The extremely low number of intercity bus and rail riders in the survey increases the likelihood that the survey is not representative of the population of riders.

[d]The number of daily trips made by transit divided by the total number of daily trips, among those surveyed.

TABLE 36. FRACTIONAL DISTRIBUTION OF MODES OF ACCESS TO BUS OR RAIL TRANSIT: SACRAMENTO AREA (SACRAMENTO AREA COUNCIL OF GOVERNMENTS REGION)

	Line-haul transit					
Mode of access to transit	*Local bus*	*Intercity bus*	*School bus*	*Light rail*	*Heavy rail*[a]	*Comm. rail*[b]
Walk	0.818	0.917	0.793	0.864	n.a.	n.a.
Drive alone	0.000	0.000	0.027	0.000	n.a.	n.a.
Car passenger	0.159	0.083	0.180	0.000	n.a.	n.a.
Bicycle	0.000	0.000	0.000	0.000	n.a.	n.a.
Local bus	0.000	0.000	0.000	0.091	n.a.	n.a.
Intercity bus	0.000	0.000	0.000	0.000	n.a.	n.a.
School bus	0.000	0.000	0.000	0.000	n.a.	n.a.
Light rail	0.000	0.000	0.000	0.000	n.a.	n.a.
Heavy rail[a]	0.000	0.000	0.000	0.000	n.a.	n.a.
Commuter rail[b]	0.000	0.000	0.000	0.000	n.a.	n.a.
Dial-a-ride	0.000	0.000	0.000	0.000	n.a.	n.a.
Other method	0.023	0.000	0.000	0.045	n.a.	n.a.
Transit trips in survey[c]	**44**	**12**	**222**	**22**	**0**	**0**
All transit/all trips[d]	*0.004*	*0.001*	*0.022*	*0.002*	*0.000*	*0.000*

Source: our analysis of the primary data from the 1991 statewide travel survey conducted by the California Department of Transportation (1993). n.a. = not applicable (no trips reported by that mode).

[a]BART, in the San Francisco Bay Area, was the only heavy-rail system in operation in California at the time of the 1991 survey.

[b]Caltrain, in the San Francisco Bay Area, was the only commuter-rail system in operation in California at the time of the 1991 survey.

[c]This is the actual number of daily trips by transit, *among those surveyed.* We have not scaled the results to represent total trips by transit for the entire population of the whole region. The extremely low number of intercity bus and light-rail riders in the survey increases the likelihood that the survey is not representative of the population of riders.

[d]The number of daily trips made by transit divided by the total number of daily trips, among those surveyed.

TABLE 37. FRACTIONAL DISTRIBUTION OF MODES OF ACCESS TO BUS OR RAIL TRANSIT: LOS ANGELES AREA (SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS REGION)

	Line-haul transit					
Mode of access to transit	*Local bus*	*Intercity bus*	*School bus*	*Light rail*	*Heavy rail*[a]	*Comm. rail*[b]
Walk	0.819	0.857	0.860	0.667	n.a.	n.a.
Drive alone	0.067	0.020	0.017	0.167	n.a.	n.a.
Car passenger	0.022	0.041	0.118	0.000	n.a.	n.a.
Bicycle	0.008	0.000	0.000	0.000	n.a.	n.a.
Local bus	0.081	0.041	0.004	0.167	n.a.	n.a.
Intercity bus	0.000	0.041	0.000	0.000	n.a.	n.a.
School bus	0.000	0.000	0.000	0.000	n.a.	n.a.
Light rail	0.000	0.000	0.000	0.000	n.a.	n.a.
Heavy rail[a]	0.000	0.000	0.000	0.000	n.a.	n.a.
Commuter rail[b]	0.000	0.000	0.000	0.000	n.a.	n.a.
Dial-a-ride	0.000	0.000	0.000	0.000	n.a.	n.a.
Other method	0.003	0.000	0.000	0.000	n.a.	n.a.
Transit trips in survey[c]	**360**	**49**	**229**	**6**	**0**	**0**
All transit/all trips[d]	*0.013*	*0.002*	*0.008*	*0.000*	*0.000*	*0.000*

Source: our analysis of the primary data from the 1991 statewide travel survey conducted by the California Department of Transportation (1993). n.a. = not applicable (no trips reported by that mode).

[a]BART, in the San Francisco Bay Area, was the only heavy-rail system in operation in California at the time of the 1991 survey.

[b]Caltrain, in the San Francisco Bay Area, was the only commuter-rail system in operation in California at the time of the 1991 survey.

[c]This is the actual number of daily trips by transit, *among those surveyed*. We have not scaled the results to represent total trips by transit for the entire population of the whole region. The extremely low number light rail passengers in the survey increases the likelihood that the survey is not representative of the total population of light-rail users.

[d]The number of daily trips made by transit divided by the total number of daily trips, among those surveyed.

TABLE 38. FRACTIONAL DISTRIBUTION OF MODES OF ACCESS TO BUS OR RAIL TRANSIT: SAN DIEGO AREA

Mode of access to transit	Line-haul transit					
	Local bus	*Intercity bus*	*School bus*	*Light rail*	*Heavy rail*[a]	*Comm. rail*[b]
Walk	0.678	1.000	0.837	0.313	n.a.	n.a.
Drive alone	0.017	0.000	0.034	0.250	n.a.	n.a.
Car passenger	0.169	0.000	0.124	0.000	n.a.	n.a.
Bicycle	0.000	0.000	0.006	0.000	n.a.	n.a.
Local bus	0.085	0.000	0.000	0.250	n.a.	n.a.
Intercity bus	0.000	0.000	0.000	0.000	n.a.	n.a.
School bus	0.000	0.000	0.000	0.000	n.a.	n.a.
Light rail	0.017	0.000	0.000	0.125	n.a.	n.a.
Heavy rail[a]	0.000	0.000	0.000	0.000	n.a.	n.a.
Commuter rail[b]	0.000	0.000	0.000	0.000	n.a.	n.a.
Dial-a-ride	0.017	0.000	0.000	0.000	n.a.	n.a.
Other method	0.017	0.000	0.000	0.063	n.a.	n.a.
Transit trips in survey[c]	**59**	**6**	**178**	**16**	**0**	**0**
All transit/all trips[d]	*0.009*	*0.001*	*0.028*	*0.002*	*0.000*	*0.000*

Source: our analysis of the primary data from the 1991 statewide travel survey conducted by the California Department of Transportation (1993). n.a. = not applicable (no trips reported by that mode).

[a]BART, in the San Francisco Bay Area, was the only heavy-rail system in operation in California at the time of the 1991 survey.

[b]Caltrain, in the San Francisco Bay Area, was the only commuter-rail system in operation in California at the time of the 1991 survey.

[c]This is the actual number of daily trips by transit, *among those surveyed*. We have not scaled the results to represent total trips by transit for the entire population of the whole region. The extremely low number of intercity bus and light-rail riders in the survey increases the likelihood that the survey is not representative of the population of riders.

[d]The number of daily trips made by transit divided by the total number of daily trips, among those surveyed.

TABLE 39. FRACTIONAL DISTRIBUTION OF MODES OF ACCESS TO BUS OR RAIL TRANSIT: SAN FRANCISCO BAY AREA, SACRAMENTO AREA, LOS ANGELES AREA, SAN DIEGO AREA

	Line-haul transit					
Mode of access to transit	*Local bus*	*Intercity bus*	*School bus*	*Light rail*	*Heavy rail[a]*	*Comm. rail[b]*
Walk	0.818	0.850	0.838	0.642	0.639	0.700
Drive alone	0.051	0.038	0.024	0.151	0.111	0.200
Car passenger	0.050	0.063	0.133	0.000	0.083	0.000
Bicycle	0.006	0.000	0.001	0.000	0.000	0.000
Local bus	0.064	0.025	0.001	0.132	0.000	0.000
Intercity bus	0.000	0.025	0.000	0.000	0.000	0.000
School bus	0.002	0.000	0.000	0.000	0.000	0.000
Light rail	0.002	0.000	0.000	0.038	0.000	0.000
Heavy rail[a]	0.000	0.000	0.000	0.000	0.056	0.100
Commuter rail[b]	0.000	0.000	0.000	0.000	0.028	0.000
Dial-a-ride	0.002	0.000	0.000	0.000	0.028	0.000
Other method	0.006	0.000	0.001	0.038	0.056	0.000
Transit trips in survey[c]	**544**	**80**	**697**	**53**	**36**	**10**
All transit/all trips[d]	*0.011*	*0.002*	*0.014*	*0.001*	*0.001*	*0.000*

Source: our analysis of the primary data from the 1991 statewide travel survey conducted by the California Department of Transportation (1993). n.a. = not applicable (no trips reported by that mode).

[a]BART, in the San Francisco Bay Area, was the only heavy-rail system in operation in California at the time of the 1991 survey.

[b]Caltrain, in the San Francisco Bay Area, was the only commuter-rail system in operation in California at the time of the 1991 survey.

[c]This is the actual number of daily trips by transit, *among those surveyed*. We have not scaled the results to represent total trips by transit for the entire population of the whole region.

[d]The number of daily trips made by transit divided by the total number of daily trips, among those surveyed.

TABLE 40. SUMMARY OF SURVEYS OF MODES OF ACCESS TO TRANSIT

System	*Year*	Mode of access (fractional shares)				
		Drive car	*Car pass.*	*Walk*	*Feed Bus*	*Other*
Rapid Rail Transit						
Atlanta (WMATA)[a]	1980	0.125	0.076	0.275	0.515	0.009
Boston (MBTA)[a]	1978	0.066	0.036	0.642	0.231	0.025
San Francisco (BART)[a]	1976	0.276	0.206	0.302	0.201	0.015
San Francisco (BART)[b]	1973	0.350	0.240	0.240	0.140	0.030
Washington (WMATA)[a]	1984	0.175	0.123	0.319	0.336	0.047
Chicago (Orange line)[c]	1994	0.130[d]	0.113	0.261	0.407	0.089
Generic old heavy rail[e]	ca. 1977	0.400		0.400	0.200	0.000
Generic new heavy rail[e]	ca. 1977	0.700		0.200	0.100	0.000
Commuter Rail						
Philadelphia (Lindenwold line)[b]	1970	0.670[d]	0.230	0.050	0.050	0.000
Los Angeles (Metrolink)[f]	1994	0.674	0.250[g]	0.003	0.073	0.00
Generic commuter rail[e]	ca. 1977	0.800		0.150	0.050	0.000
Toronto GO-rail[h]	1987	0.725		n.e.	0.275	
Light rail						
San Diego Trolley[a]	1983	0.138	0.079	0.582	0.196	0.005
Generic light rail[e]	ca. 1977	0.300		0.500	0.200	0.000
Bus						
San Bernadino Busway[b]	1974	0.550[d]	0.170	0.230	0.050	0.000
Shirley Busway (Wash. D. C.)[b]	1973	0.240[d]	0.090	0.670	0.000	0.000
Generic express bus[e]	ca. 1977	0.250	n.e.	0.750	0.000	0.000

n.e. = not estimated.

[a]From Charles River Associates (1988). The original source is cited as "reports from individual study areas". The results for Boston (MBTA) are based on surveys from 6:00 AM to midnight; the results for San Francisco (BART) are based on surveys from 6:00 AM to 3:00 PM, and the results for Washington (WMATA) are based on surveys from 6:30 AM to 9:30 am. "Car passenger" column includes carpool and kiss-and-ride.

[b]From Curry (1976). The data for San Francisco (BART) are from the BART Office of Research; the results for Philadelphia (Lindenwold Line) are from onboard surveys; the results for the San Bernadino Busway are from an onboard survey; and the results for the Shirley Busway are from an onboard survey during the morning peak period.

[c]From a survey of riders in March , 1994 (LaBelle and Stuart, 1995). The Orange line, which opened October 31, 1993, runs around the Chicago Loop and then 11.75 miles out to Midway Airport.

[d]Park and ride.

[e]"Middle estimates" from the Congressional Budget Office (1977). The CBO also provides estimates of modes of access to BART, the Shirley Busway, and the South Shore Extension of the Boston rail system.

[f]From a survey of 288 passengers on the Metrolink's Riverside, California line on November 16, 1994 (Barth et al., 1996).

[g]Barth et al. (1996) reported that 15% of the rail passengers had been dropped off at the station, and that 10% had carpooled.

[h]From the 1987 survey of riders of the commuter rail system of the Greater Toronto Area (Fan et al., 1993). Fan et al. (1993) report access by "auto" and by "transit," with no further disaggregation.

TABLE 41. CBO (1977) ESTIMATE OF CIRCUITY OF TRANSIT TRIPS, AND FRACTION OF TRIP DEVOTED TO TRANSIT

Line-haul mode	Percent of trip devoted to access	Circuity relative to automobile trip
Automobile	0	1.0
Carpool	0	1.15
Vanpool	0	1.20
Dial-a-ride	0	1.40
Old heavy rail	15	1.20
New heavy rail[a]	18	1.30
Commuter rail[b]	18	1.30
Light rail	10	1.20
Express bus	10	1.10

Source: Congressional Budget Office (1977). The access modes are not specified here.

[a]LaBelle and Stuart (1995) surveyed riders of the Chicago rapid-rail “Orange” line in March 1994 and found that the average length of access by auto was 4.0 miles. The average line-haul distance appears to have been around 9 miles. The average distance of the door-to-door drive was 11.3 miles. These results indicate that for access by auto, about 30% of the total trip mileage was access, and the circuity relative to driving door-to-door was 1.15. The access percentage and the circuity estimated for all modes of access (bus, walk, car) would be lower.

[b]A survey of passengers on the Riverside Metrolink commuter rail in Los Angeles appears to support this estimate of the fraction of the trip devoted to access (Barth et al., 1996). Most of the rail passengers drove from home to the station, an average of 13 miles. It appears that the whole trip was on the order of 65 miles, of which then about 20% was access. However, the data of Barth et al. (1996) suggest that the circuity is less than 1.30.

TABLE 42. OUR ASSUMPTIONS: LENGTH OF ACCESS TRIPS TO TRANSIT, AND OF CARPOOL AND VANPOOL TRIPS, RELATIVE TO LENGTH OF BASELINE DIRECT SINGLE-PASSENGER-AUTO TRIP

mode	*Sacramento*	*San Francisco*	*Los Angeles*	*San Diego*	*Boston*	*Wash. D. C.*
Carpool	1.10	1.10	1.10	1.10	1.10	1.10
Vanpool	1.15	1.15	1.15	1.15	1.15	1.15
Bus						
Line haul	1.05	1.05	1.05	1.05	1.05	1.05
access by auto	0.15	0.15	0.15	0.15	0.15	0.15
access by car or vanpool	use access by auto multiplied by carpool or vanpool ratio above					
access by walk or other	0.04	0.04	0.04	0.04	0.04	0.04
LRT						
Line haul	1.00	1.00	1.00	1.00	1.00	1.00
access by auto	0.20	0.20	0.20	0.20	0.20	0.20
access by car or vanpool	use access by auto multiplied by carpool or vanpool ratio above					
access by bus	0.20	0.20	0.20	0.20	0.20	0.20
access by walk or other	0.05	0.05	0.05	0.05	0.05	0.05
HRT						
Line haul	1.00	1.00	1.00	1.00	1.00	1.00
access by auto	0.25	0.25	0.25	0.25	0.25	0.25
access by car or vanpool	use access by auto multiplied by carpool or vanpool ratio above					
access by bus	0.25	0.25	0.25	0.25	0.25	0.25
access by LRT	0.30	0.30	0.30	0.30	0.30	0.30
access by walk or other	0.05	0.05	0.05	0.05	0.05	0.05

Source: Table 41 and our estimates. LRT = light-rail transit, HRT = heavy-rail transit.

TABLE 43. OUR ASSUMPTIONS: DISTRIBUTION OF MODES OF ACCESS TO TRANSIT

mode	*Sacramento*	*San Francisco*	*Los Angeles*	*San Diego*	*Boston*	*Wash. D. C.*
Bus						
Line haul	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
access by car or van	0.10	0.10	0.10	0.10	0.10	0.10
access by walk or other	0.90	0.90	0.90	0.90	0.90	0.90
LRT						
Line haul	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
access by car or van	0.15	0.15	0.15	0.15	0.15	0.15
access by bus	0.15	0.15	0.15	0.15	0.15	0.15
access by walk or other	0.70	0.70	0.70	0.70	0.70	0.70
HRT						
Line haul	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
access by car or van	0.25	0.25	0.25	0.25	0.25	0.25
access by bus	0.05	0.05	0.05	0.05	0.05	0.05
access by LRT	0.02	0.02	0.02	0.02	0.02	0.02
access by walk or other	0.68	0.68	0.68	0.68	0.68	0.68

Source: Tables 39 and 40, and our estimates. LRT = light-rail transit, HRT = heavy-rail transit.

TABLE 44. INPUT "BASE-CASE" PARAMETERS FOR MOTOR VEHICLES USED IN DIRECT DOOR-TO-DOOR TRIP AND TO ACCESS BUSES AND TRAINS.

	Sacramento		**San Francisco**		**Los Angeles**		**San Diego**	
	Direct	*Access*	*Direct*	*Access*	*Direct*	*Access*	*Direct*	*Access*
Fuel for cars	gasoline	LPG	EV	EV	EtOH	EV	CNG	MeOH
Fuel for buses	CNG	CNG	diesel	diesel	MeOH	MeOH	CNG	CNG
Car or van	car	van	car	van	car	van	car	van
Transit mode	n.a.	LRT	n.a.	HRT	n.a.	bus	n.a.	LRT
Carpool or vanpool?	no	no	yes	yes	yes	no	no	no

CNG = compressed natural gas; LPG = liquefied petroleum gas; EV = electric vehicle; EtOH = ethanol; MeOH = methanol; LRT = light-rail transit; HRT = heavy-rail transit; n.a. = not applicable.

The base-case is just a scenario, not a prediction of fuels, modes, vehicle occupancy or anything else in a particular region. We examine many other scenarios.

TABLE 45. PERCENTAGE CHANGE IN EMISSIONS PER PASSENGER TRIP, FULL TRIPS INVOLVING TRANSIT VERSUS DOOR-TO-DOOR TRIP BY MOTOR VEHICLES

	Sacra-mento	San Fran-cisco	Los Angeles	San Diego	Boston	Washing-ton D. C.
NMHC	-97.5%	301.3%	-44.4%	-7.2%	90.2%	-51.6%
CO	-91.3%	87.3%	48.6%	-83.7%	27.9%	-95.2%
NO_x	-70.5%	39.9%	148.4%	-71.2%	793.0%	95.2%
SO_x	84.7%	-5.4%	-89.5%	66.0%	251.4%	708.9%
PM_{10}	-91.5%	-93.1%	-12.0%	-92.3%	94.6%	-94.2%
C_6H_6	-99.0%	87.5%	1013.2%	93.1%	29.7%	353.8%
HCHO	-87.9%	111.1%	1845.7%	-67.8%	706.2%	-74.3%
CH_3CHO	-88.4%	4490.4%	-82.5%	-91.4%	660.4%	-94.9%
$CH_2CHCHCH_2$	-98.6%	infinite	375.9%	infinite	1530.6%	infinite
CH_2CH_2	-93.6%	infinite	25.2%	-94.2%	-90.3%	-99.1%
Fuelcycle GHG	-87.5%	19.1%	52.8%	-59.4%	107.3%	27.6%

CNG = compressed natural gas; LPG = liquefied petroleum gas; EV = electric vehicle; LRT = light-rail transit; HRT = heavy-rail transit; n.a. = not applicable; NMHC = nonmethane hydrocarbons; CO = carbon monoxide; NOx = nitrogen oxides; SOx = sulfur oxides; PM_{10} = particulate matter of less than 10 microns; C_6H_6 = benzene; HCHO = formaldehyde; CH_3CHO = acetaldehyde; $CH_2CHCHCH_2$ = 1,3 butadiene; CH_2CH_2 = ethylene (ethene).

Percentage change is calculated as 100*(Tr-Ad) / Ad, where Tr is grams emitted per passenger trip involving transit, and Ad is grams emitted per door-to-door auto trip. A negative percentage change means that transit reduces emissions per passenger trip. If the direct motor-vehicle trip emits zero, then any emissions from transit will be an "infinite" increase.

These results are for the “base-case” parameters presented in tables throughout this report (e.g., Tables 1, 3, 42, 43, 44).

Emissions from fuel production and station and infrastructure operation and maintenance are included. For transit, emissions from access trips are included.

Because we could not find data on emissions of emissions of acetaldehyde, 1,3-butadiene, and ethylene from power plants (Table 22), the percentage changes shown here overstate the benefit of using electric transportation options.

SCENARIO ANALYSES

SEPARATE SPREADSHEET TABLES NOT AVAILABLE IN THIS VERSION

THE PRESIDENT'S CLIMATE ACTION PLAN

Executive Office of the President

June 2013

THE WHITE HOUSE
WASHINGTON

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PRESIDENT OBAMA'S CLIMATE ACTION PLAN

"We, the people, still believe that our obligations as Americans are not just to ourselves, but to all posterity. We will respond to the threat of climate change, knowing that the failure to do so would betray our children and future generations. Some may still deny the overwhelming judgment of science, but none can avoid the devastating impact of raging fires and crippling drought and more powerful storms.

The path towards sustainable energy sources will be long and sometimes difficult. But America cannot resist this transition, we must lead it. We cannot cede to other nations the technology that will power new jobs and new industries, we must claim its promise. That's how we will maintain our economic vitality and our national treasure -- our forests and waterways, our croplands and snow-capped peaks. That is how we will preserve our planet, commanded to our care by God. That's what will lend meaning to the creed our fathers once declared."

-- President Obama, Second Inaugural Address, January 2013

THE CASE FOR ACTION

While no single step can reverse the effects of climate change, we have a moral obligation to future generations to leave them a planet that is not polluted and damaged. Through steady, responsible action to cut carbon pollution, we can protect our children's health and begin to slow the effects of climate change so that we leave behind a cleaner, more stable environment.

In 2009, President Obama made a pledge that by 2020, America would reduce its greenhouse gas emissions in the range of 17 percent below 2005 levels if all other major economies agreed to limit their emissions as well. Today, the President remains firmly committed to that goal and to building on the progress of his first term to help put us and the world on a sustainable long-term trajectory. Thanks in part to the Administration's success in doubling America's use of wind, solar, and geothermal energy and in establishing the toughest fuel economy standards in our history, we are creating new jobs, building new industries, and reducing dangerous carbon pollution which contributes to climate change. In fact, last year, carbon emissions from the energy sector fell to the lowest level in two decades. At the same time, while there is more work to do, we are more energy secure than at any time in recent history. In 2012, America's net oil imports fell to the lowest level in 20 years and we have become the world's leading producer of natural gas – the cleanest-burning fossil fuel.

While this progress is encouraging, climate change is no longer a distant threat – we are already feeling its impacts across the country and the world. Last year was the warmest year ever in the contiguous United States and about one-third of all Americans experienced 10 days or more of 100-degree heat. The 12 hottest years on record have all come in the last 15 years. Asthma rates have doubled in the past 30 years and our children will suffer more asthma attacks as air pollution gets worse. And increasing floods, heat waves, and droughts have put farmers out of business, which is already raising food prices dramatically.

These changes come with far-reaching consequences and real economic costs. Last year alone, there were 11 different weather and climate disaster events with estimated losses exceeding $1 billion each across the United States. Taken together, these 11 events resulted in over $110 billion in estimated damages, which would make it the second-costliest year on record.

In short, America stands at a critical juncture. Today, President Obama is putting forward a broad-based plan to cut the carbon pollution that causes climate change and affects public health. Cutting carbon pollution will help spark business innovation to modernize our power plants, resulting in cleaner forms of American-made energy that will create good jobs and cut our dependence on foreign oil. Combined with the Administration's other actions to increase the efficiency of our cars and household appliances, the President's plan will reduce the amount of energy consumed by American families, cutting down on their gas and utility bills. The plan, which consists of a wide variety of executive actions, has three key pillars:

1) **Cut Carbon Pollution in America:** In 2012, U.S. carbon emissions fell to the lowest level in two decades even as the economy continued to grow. To build on this progress, the Obama Administration is putting in place tough new rules to cut carbon pollution – just like we have for other toxins like mercury and arsenic – so we protect the health of our children and move our economy toward American-made clean energy sources that will create good jobs and lower home energy bills.

2) **Prepare the United States for the Impacts of Climate Change:** Even as we take new steps to reduce carbon pollution, we must also prepare for the impacts of a changing climate that are already being felt across the country. Moving forward, the Obama Administration will help state and local governments strengthen our roads, bridges, and shorelines so we can better protect people's homes, businesses and way of life from severe weather.

3) **Lead International Efforts to Combat Global Climate Change and Prepare for its Impacts:** Just as no country is immune from the impacts of climate change, no country can meet this challenge alone. That is why it is imperative for the United States to couple action at home with leadership internationally. America must help forge a truly global solution to this global challenge by galvanizing international action to significantly reduce emissions (particularly among the major emitting countries), prepare for climate impacts, and drive progress through the international negotiations.

Climate change represents one of our greatest challenges of our time, but it is a challenge uniquely suited to America's strengths. Our scientists will design new fuels, and our farmers will grow them. Our engineers to devise new sources of energy, our workers will build them, and our businesses will sell them. All of us will need to do our part. If we embrace this challenge, we will not just create new jobs and new industries and keep America on the cutting edge; we will save lives, protect and preserve our treasured natural resources, cities, and coastlines for future generations.

What follows is a blueprint for steady, responsible national and international action to slow the effects of climate change so we leave a cleaner, more stable environment for future generations. It highlights progress already set in motion by the Obama Administration to advance these goals and sets forth new steps to achieve them.

CUT CARBON POLLUTION IN AMERICA

In 2009, President Obama made a commitment to reduce U.S. greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020. The President remains firmly committed to achieving that goal. While there is more work to do, the Obama Administration has already made significant progress by doubling generation of electricity from wind, solar, and geothermal, and by establishing historic new fuel economy standards. Building on these achievements, this document outlines additional steps the Administration will take – in partnership with states, local communities, and the private sector – to continue on a path to meeting the President's 2020 goal.

I. Deploying Clean Energy

Cutting Carbon Pollution from Power Plants: Power plants are the largest concentrated source of emissions in the United States, together accounting for roughly one-third of all domestic greenhouse gas emissions. We have already set limits for arsenic, mercury, and lead, but there is no federal rule to prevent power plants from releasing as much carbon pollution as they want. Many states, local governments, and companies have taken steps to move to cleaner electricity sources. More than 35 states have renewable energy targets in place, and more than 25 have set energy efficiency targets.

Despite this progress at the state level, there are no federal standards in place to reduce carbon pollution from power plants. In April 2012, as part of a continued effort to modernize our electric power sector, the Obama Administration proposed a carbon pollution standard for new power plants. The Environmental Protection Agency's proposal reflects and reinforces the ongoing trend towards cleaner technologies, with natural gas increasing its share of electricity generation in recent years, principally through market forces and renewables deployment growing rapidly to account for roughly half of new generation capacity installed in 2012.

With abundant clean energy solutions available, and building on the leadership of states and local governments, we can make continued progress in reducing power plant pollution to improve public health and the environment while supplying the reliable, affordable power needed for economic growth. By doing so, we will continue to drive American leadership in clean energy technologies, such as efficient natural gas, nuclear, renewables, and clean coal technology.

To accomplish these goals, President Obama is issuing a Presidential Memorandum directing the Environmental Protection Agency to work expeditiously to complete carbon pollution standards for both new and existing power plants. This work will build on the successful first-term effort to develop greenhouse gas and fuel economy standards for cars and trucks. In developing the standards, the President has asked the Environmental Protection Agency to build on state leadership, provide flexibility, and take advantage of a wide range of energy sources and technologies including many actions in this plan.

Promoting American Leadership in Renewable Energy: During the President's first term, the United States more than doubled generation of electricity from wind, solar, and geothermal sources. To ensure America's continued leadership position in clean energy, President Obama has set a goal to double renewable electricity generation once again by 2020. In order to meet this ambitious target, the Administration is announcing a number of new efforts in the following key areas:

- **Accelerating Clean Energy Permitting:** In 2012 the President set a goal to issue permits for 10 gigawatts of renewables on public lands by the end of the year. The Department of the Interior achieved this goal ahead of schedule and the President has directed it to permit an additional 10 gigawatts by 2020. Since 2009, the Department of Interior has approved 25 utility-scale solar facilities, nine wind farms, and 11 geothermal plants, which will provide enough electricity to power 4.4 million homes and support an estimated 17,000 jobs. The Administration is also taking steps to encourage the development of hydroelectric power at existing dams. To develop and demonstrate improved permitting procedures for such projects, the Administration will designate the Red Rock Hydroelectric Plant on the Des Moines River in Iowa to participate in its Infrastructure Permitting Dashboard for high-priority projects. Also, the Department of Defense – the single largest consumer of energy in the United States – is committed to deploying 3 gigawatts of renewable energy on military installations, including solar, wind, biomass, and geothermal, by 2025. In addition, federal agencies are setting a new goal of reaching 100 megawatts of installed renewable capacity across the federally subsidized housing stock by 2020. This effort will include conducting a survey of current projects in order to track progress and facilitate the sharing of best practices.

- **Expanding and Modernizing the Electric Grid:** Upgrading the country's electric grid is critical to our efforts to make electricity more reliable, save consumers money on their energy bills, and promote clean energy sources. To advance these important goals, President Obama signed a Presidential Memorandum this month that directs federal agencies to streamline the siting, permitting and review process for transmission projects across federal, state, and tribal governments.

Unlocking Long-Term Investment in Clean Energy Innovation: The Fiscal Year 2014 Budget continues the President's commitment to keeping the United States at the forefront of clean energy research, development, and deployment by increasing funding for clean energy technology across all agencies by 30 percent, to approximately $7.9 billion. This includes investment in a range of energy technologies, from advanced biofuels and emerging nuclear technologies – including small modular reactors – to clean coal. To continue America's leadership in clean energy innovation, the Administration will also take the following steps:

- **Spurring Investment in Advanced Fossil Energy Projects:** In the coming weeks, the Department of Energy will issue a Federal Register Notice announcing a draft of a solicitation that would make up to $8 billion in (self-pay) loan guarantee authority available for a wide array of advanced fossil energy projects under its Section 1703 loan guarantee program. This solicitation is designed to support investments in innovative technologies that can cost-effectively meet financial and policy goals, including the avoidance, reduction, or sequestration of anthropogenic emissions of greenhouse gases. The proposed solicitation will cover a broad range of advanced fossil energy projects. Reflecting the Department's commitment to continuous improvement in program management, it will take comment on the draft solicitation, with a plan to issue a final solicitation by the fall of 2013.

- **Instituting a Federal Quadrennial Energy Review:** Innovation and new sources of domestic energy supply are transforming the nation's energy marketplace, creating economic opportunities at the same time they raise environmental challenges. To ensure that federal energy policy meets our economic, environmental, and security goals in this changing landscape, the Administration will conduct a Quadrennial Energy Review which will be led by the White House Domestic Policy Council and Office of Science and Technology Policy, supported by a Secretariat established at the Department of Energy, and involving the robust engagement of federal agencies and outside stakeholders. This first-ever review will focus on infrastructure challenges, and will identify the threats, risks, and opportunities for U.S. energy and climate security, enabling the federal government to translate policy goals into a set of analytically based, clearly articulated, sequenced and integrated actions, and proposed investments over a four-year planning horizon.

II. Building a 21st-Century Transportation Sector

Increasing Fuel Economy Standards: Heavy-duty vehicles are currently the second largest source of greenhouse gas emissions within the transportation sector. In 2011, the Obama Administration finalized the first-ever fuel economy standards for Model Year 2014-2018 for heavy-duty trucks, buses, and vans. These standards will reduce greenhouse gas emissions by approximately 270 million metric tons and save 530 million barrels of oil. During the President's second term, the Administration will once again partner with industry leaders and other key stakeholders to develop post-2018 fuel economy standards for heavy-duty vehicles to further reduce fuel consumption through the application of advanced cost-effective technologies and continue efforts to improve the efficiency of moving goods across the United States.

The Obama Administration has already established the toughest fuel economy standards for passenger vehicles in U.S. history. These standards require an average performance equivalent of 54.5 miles per gallon by 2025, which will save the average driver more than $8,000 in fuel costs over the lifetime of the vehicle and eliminate six billion metric tons of carbon pollution – more than the United States emits in an entire year.

Developing and Deploying Advanced Transportation Technologies: Biofuels have an important role to play in increasing our energy security, fostering rural economic development, and reducing greenhouse gas emissions from the transportation sector. That is why the Administration supports the Renewable Fuels Standard, and is investing in research and development to help bring next-generation biofuels on line. For example, the United States Navy and Departments of Energy and Agriculture are working with the private sector to accelerate the development of cost-competitive advanced biofuels for use by the military and commercial sectors. More broadly, the Administration will continue to leverage partnerships between the private and public sectors to deploy cleaner fuels, including advanced batteries and fuel cell technologies, in every transportation mode. The Department of Energy's eGallon informs drivers about electric car operating costs in their state – the national average is only $1.14 per gallon of gasoline equivalent, showing the promise for consumer pocketbooks of electric-powered vehicles. In addition, in the coming months, the Department of Transportation will work with other agencies to further explore strategies for integrating alternative fuel vessels into the U.S. flag fleet. Further, the Administration will continue to work with states, cities and towns through the Department of Transportation, the Department of Housing and Urban Development, and the Environmental Protection Agency to improve transportation options, and lower transportation costs while protecting the environment in communities nationwide.

III. Cutting Energy Waste in Homes, Businesses, and Factories

Reducing Energy Bills for American Families and Businesses: Energy efficiency is one of the clearest and most cost-effective opportunities to save families money, make our businesses more competitive, and reduce greenhouse gas emissions. In the President's first term, the Department of Energy and the Department of Housing and Urban Development completed efficiency upgrades in more than one million homes, saving many families more than $400 on their heating and cooling bills in the first year alone. The Administration will take a range of new steps geared towards achieving President Obama's goal of doubling energy productivity by 2030 relative to 2010 levels:

- **Establishing a New Goal for Energy Efficiency Standards:** In President Obama's first term, the Department of Energy established new minimum efficiency standards for dishwashers, refrigerators, and many other products. Through 2030, these standards will cut consumers' electricity bills by hundreds of billions of dollars and save enough electricity to power more than 85 million homes for two years. To build on this success, the Administration is setting a new goal: Efficiency standards for appliances and federal buildings set in the first and second terms combined will reduce carbon pollution by at least 3 billion metric tons cumulatively by 2030 – equivalent to nearly one-half of the carbon pollution from the entire U.S. energy sector for one year – while continuing to cut families' energy bills.

- **Reducing Barriers to Investment in Energy Efficiency:** Energy efficiency upgrades bring significant cost savings, but upfront costs act as a barrier to more widespread investment. In response, the Administration is committing to a number of new executive actions. As soon as this fall, the Department of Agriculture's Rural Utilities Service will finalize a proposed update to its Energy Efficiency and Conservation Loan Program to provide up to $250 million for rural utilities to finance efficiency investments by businesses and homeowners across rural America. The Department is also streamlining its Rural Energy for America program to provide grants and loan guarantees directly to agricultural producers and rural small businesses for energy efficiency and renewable energy systems.

  In addition, the Department of Housing and Urban Development's efforts include a $23 million Multifamily Energy Innovation Fund designed to enable affordable housing providers, technology firms, academic institutions, and philanthropic organizations to test new approaches to deliver cost-effective residential energy. In order to advance ongoing efforts and bring stakeholders together, the Federal Housing Administration will convene representatives of the lending community and other key stakeholders for a mortgage roundtable in July to identify options for factoring energy efficiency into the mortgage underwriting and appraisal process upon sale or refinancing of new or existing homes.

- **Expanding the President's Better Buildings Challenge:** The Better Buildings Challenge, focused on helping American commercial and industrial buildings become at least 20 percent more energy efficient by 2020, is already showing results. More than 120 diverse organizations, representing over 2 billion square feet are on track to meet the 2020 goal: cutting energy use by an average 2.5 percent annually, equivalent to about $58 million in energy savings per year. To continue this success, the Administration will expand the program to multifamily housing – partnering both with private and affordable building owners and public housing agencies to cut energy waste. In addition, the Administration is launching the Better Buildings Accelerators, a new track that will support and encourage adoption of State and local policies to cut energy waste, building on the momentum of ongoing efforts at that level.

IV. Reducing Other Greenhouse Gas Emissions

Curbing Emissions of Hydrofluorocarbons: Hydrofluorocarbons (HFCs), which are primarily used for refrigeration and air conditioning, are potent greenhouse gases. In the United States, emissions of HFCs are expected to nearly triple by 2030, and double from current levels of 1.5 percent of greenhouse gas emissions to 3 percent by 2020.

To reduce emissions of HFCs, the United States can and will lead both through international diplomacy as well as domestic actions. In fact, the Administration has already acted by including a flexible and powerful incentive in the fuel economy and carbon pollution standards for cars and trucks to encourage automakers to reduce HFC leakage and transition away from the most potent HFCs in vehicle air conditioning systems. Moving forward, the Environmental Protection Agency will use its authority through the Significant New Alternatives Policy Program to encourage private sector investment in low-emissions technology by identifying and approving climate-friendly chemicals while prohibiting certain uses of the most harmful chemical alternatives. In addition, the President has directed his Administration to purchase cleaner alternatives to HFCs whenever feasible and transition over time to equipment that uses safer and more sustainable alternatives.

Reducing Methane Emissions: Curbing emissions of methane is critical to our overall effort to address global climate change. Methane currently accounts for roughly 9 percent of domestic greenhouse gas emissions and has a global warming potential that is more than 20 times greater than carbon dioxide. Notably, since 1990, methane emissions in the United States have decreased by 8 percent. This has occurred in part through partnerships with industry, both at home and abroad, in which we have demonstrated that we have the technology to deliver emissions reductions that benefit both our economy and the environment. To achieve additional progress, the Administration will:

- **Developing an Interagency Methane Strategy:** The Environmental Protection Agency and the Departments of Agriculture, Energy, Interior, Labor, and Transportation will develop a comprehensive, interagency methane strategy. The group will focus on assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions, and identifying existing authorities and incentive-based opportunities to reduce methane emissions.

- **Pursuing a Collaborative Approach to Reducing Emissions:** Across the economy, there are multiple sectors in which methane emissions can be reduced, from coal mines and landfills to agriculture and oil and gas development. For example, in the agricultural sector, over the last three years, the Environmental Protection Agency and the Department of Agriculture have worked with the dairy industry to increase the adoption of methane digesters through loans, incentives, and other assistance. In addition, when it comes to the oil and gas sector, investments to build and upgrade gas pipelines will not only put more Americans to work, but also reduce emissions and enhance economic productivity. For example, as part of the Administration's effort to improve federal permitting for infrastructure projects, the interagency Bakken Federal Executive Group is working with industry, as well as state and tribal agencies, to advance the production of oil and gas in the Bakken while helping to reduce venting and flaring. Moving forward, as part of the effort to develop an interagency methane strategy, the Obama Administration will work collaboratively with state governments, as well as the private sector, to reduce emissions across multiple sectors, improve air quality, and achieve public health and economic benefits.

Preserving the Role of Forests in Mitigating Climate Change: America's forests play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. In the face of a changing climate and increased risk of wildfire, drought, and pests, the capacity of our forests to absorb carbon is diminishing. Pressures to develop forest lands for urban or agricultural uses also contribute to the decline of forest carbon sequestration. Conservation and sustainable management can help to ensure our forests continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk, and otherwise managing forests to be more resilient in the fact of climate change. The Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate.

V. Leading at the Federal Level

Leading in Clean Energy: President Obama believes that the federal government must be a leader in clean energy and energy efficiency. Under the Obama Administration, federal agencies have reduced greenhouse gas emissions by more than 15 percent – the equivalent of permanently taking 1.5 million cars off the road. To build on this record, the Administration is establishing a new goal: The federal government will consume 20 percent of its electricity from renewable sources by 2020 – more than double the current goal of 7.5 percent. In addition, the federal government will continue to pursue greater energy efficiency that reduces greenhouse gas emissions and saves taxpayer dollars.

Federal Government Leadership in Energy Efficiency: On December 2, 2011, President Obama signed a memorandum entitled "Implementation of Energy Savings Projects and Performance-Based Contracting for Energy Savings," challenging federal agencies, in support of the Better Buildings Challenge, to enter into $2 billion worth of performance-based contracts within two years. Performance contracts drive economic development, utilize private sector innovation, and increase efficiency at minimum costs to the taxpayer, while also providing long-term savings in energy costs. Federal agencies have committed to a pipeline of nearly $2.3 billion from over 300 reported projects. In coming months, the Administration will take a number of actions to strengthen efforts to promote energy efficiency, including through performance contracting. For example, in order to increase access to capital markets for investments in energy efficiency, the Administration will initiate a partnership with the private sector to work towards a standardized contract to finance federal investments in energy efficiency. Going forward, agencies will also work together to synchronize building codes – leveraging those policies to improve the efficiency of federally owned and supported building stock. Finally, the Administration will leverage the "Green Button" standard – which aggregates energy data in a secure, easy to use format – within federal facilities to increase their ability to manage energy consumption, reduce greenhouse gas emissions, and meet sustainability goals.

PREPARE THE UNITED STATES FOR THE IMPACTS OF CLIMATE CHANGE

As we act to curb the greenhouse gas pollution that is driving climate change, we must also prepare for the impacts that are too late to avoid. Across America, states, cities, and communities are taking steps to protect themselves by updating building codes, adjusting the way they manage natural resources, investing in more resilient infrastructure, and planning for rapid recovery from damages that nonetheless occur. The federal government has an important role to play in supporting community-based preparedness and resilience efforts, establishing policies that promote preparedness, protecting critical infrastructure and public resources, supporting science and research germane to preparedness and resilience, and ensuring that federal operations and facilities continue to protect and serve citizens in a changing climate.

The Obama Administration has been working to strengthen America's climate resilience since its earliest days. Shortly after coming into office, President Obama established an Interagency Climate Change Adaptation Task Force and, in October 2009, the President signed an Executive Order directing it to recommend ways federal policies and programs can better prepare the Nation for change. In May 2010, the Task Force hosted the first National Climate Adaptation Summit, convening local and regional stakeholders and decision-makers to identify challenges and opportunities for collaborative action.

In February 2013, federal agencies released Climate Change Adaptation Plans for the first time, outlining strategies to protect their operations, missions, and programs from the effects of climate change. The Department of Transportation, for example, is developing guidance for incorporating climate change and extreme weather event considerations into coastal highway projects, and the Department of Homeland Security is evaluating the challenges of changing conditions in the Arctic and along our Nation's borders. Agencies have also partnered with communities through targeted grant and technical-assistance programs—for example, the Environmental Protection Agency is working with low-lying communities in North Carolina to assess the vulnerability of infrastructure investments to sea level rise and identify solutions to reduce risks. And the Administration has continued, through the U.S. Global Change Research Program, to support science and monitoring to expand our understanding of climate change and its impacts.

Going forward, the Administration will expand these efforts into three major, interrelated initiatives to better prepare America for the impacts of climate change:

I. Building Stronger and Safer Communities and Infrastructure

By necessity, many states, cities, and communities are already planning and preparing for the impacts of climate change. Hospitals must build capacity to serve patients during more frequent heat waves, and urban planners must plan for the severe storms that infrastructure will need to withstand. Promoting on-the-ground planning and resilient infrastructure will be at the core of our work to strengthen America's communities. Specific actions will include:

Directing Agencies to Support Climate-Resilient Investment: The President will direct federal agencies to identify and remove barriers to making climate-resilient investments; identify and remove counterproductive policies that increase vulnerabilities; and encourage and support smarter, more resilient investments, including through agency grants, technical assistance, and other programs, in sectors from transportation and water management to conservation and disaster relief. Agencies will also be directed to ensure that climate risk-management considerations are fully integrated into federal infrastructure and natural resource management planning. To begin meeting this challenge, the Environmental Protection Agency is committing to integrate considerations of climate change impacts and adaptive measures into major programs, including its Clean Water and Drinking Water State Revolving Funds and grants for brownfields cleanup, and the Department of Housing and Urban Development is already requiring grant recipients in the Hurricane Sandy–affected region to take sea-level rise into account.

Establishing a State, Local, and Tribal Leaders Task Force on Climate Preparedness: To help agencies meet the above directive and to enhance local efforts to protect communities, the President will establish a short-term task force of state, local, and tribal officials to advise on key actions the federal government can take to better support local preparedness and resilience-building efforts. The task force will provide recommendations on removing barriers to resilient investments, modernizing grant and loan programs to better support local efforts, and developing information and tools to better serve communities.

Supporting Communities as they Prepare for Climate Impacts: Federal agencies will continue to provide targeted support and assistance to help communities prepare for climate-change impacts. For example, throughout 2013, the Department of Transportation's Federal Highway Administration is working with 19 state and regional partners and other federal agencies to test approaches for assessing local transportation infrastructure vulnerability to climate change and extreme weather and for improving resilience. The Administration will continue to assist tribal communities on preparedness through the Bureau of Indian Affairs, including through pilot projects and by supporting participation in federal initiatives that assess climate change vulnerabilities and develop regional solutions. Through annual federal agency "Environmental Justice Progress Reports," the Administration will continue to identify innovative ways to help our most vulnerable communities prepare for and recover from the impacts of climate change. The importance of critical infrastructure independence was brought home in the Sandy response. The Federal Emergency Management Agency and the Department of Energy are working with the private sector to address simultaneous restoration of electricity and fuels supply.

Boosting the Resilience of Buildings and Infrastructure: The National Institute of Standards and Technology will convene a panel on disaster-resilience standards to develop a comprehensive, community-based resilience framework and provide guidelines for consistently safe buildings and infrastructure – products that can inform the development of private-sector standards and codes. In addition, building on federal agencies' "Climate Change Adaptation Plans," the Administration will continue efforts to increase the resilience of federal facilities and infrastructure. The Department of Defense, for example, is assessing the relative vulnerability of its coastal facilities to climate change. In addition, the President's FY 2014 Budget proposes $200 million through the Transportation Leadership Awards program for Climate Ready Infrastructure in communities that build enhanced preparedness into their planning efforts, and that have proposed or are ready to break ground on infrastructure projects, including transit and rail, to improve resilience.

Rebuilding and Learning from Hurricane Sandy: In August 2013, President Obama's Hurricane Sandy Rebuilding Task Force will deliver to the President a rebuilding strategy to be implemented in Sandy-affected regions and establishing precedents that can be followed elsewhere. The Task Force and federal agencies are also piloting new ways to support resilience in the Sandy-affected region; the Task Force, for example, is hosting a regional "Rebuilding by Design" competition to generate innovative solutions to enhance resilience. In the transportation sector, the Department of Transportation's Federal Transit Administration (FTA) is dedicating $5.7 billion to four of the area's most impacted transit agencies, of which $1.3 billion will be allocated to locally prioritized projects to make transit systems more resilient to future disasters. FTA will also develop a competitive process for additional funding to identify and support larger, stand-alone resilience projects in the impacted region. To build coastal resilience, the Department of the Interior will launch a $100 million competitive grant program to foster partnerships and promote resilient natural systems while enhancing green spaces and wildlife habitat near urban populations. An additional $250 million will be allocated to support projects for coastal restoration and resilience across the region. Finally, with partners, the U.S. Army Corps of Engineers is conducting a $20 million study to identify strategies to reduce the vulnerability of Sandy-affected coastal communities to future large-scale flood and storm events, and the National Oceanic and Atmospheric Administration will strengthen long-term coastal observations and provide technical assistance to coastal communities.

II. Protecting our Economy and Natural Resources

Climate change is affecting nearly every aspect of our society, from agriculture and tourism to the health and safety of our citizens and natural resources. To help protect critical sectors, while also targeting hazards that cut across sectors and regions, the Administration will mount a set of sector- and hazard-specific efforts to protect our country's vital assets, to include:

Identifying Vulnerabilities of Key Sectors to Climate Change: The Department of Energy will soon release an assessment of climate-change impacts on the energy sector, including power-plant disruptions due to drought and the disruption of fuel supplies during severe storms, as well as potential opportunities to make our energy infrastructure more resilient to these risks. In 2013, the Department of Agriculture and Department of the Interior released several studies outlining the challenges a changing climate poses for America's agricultural enterprise, forests, water supply, wildlife, and public lands. This year and next, federal agencies will report on the impacts of climate change on other key sectors and strategies to address them, with priority efforts focusing on health, transportation, food supplies, oceans, and coastal communities.

Promoting Resilience in the Health Sector: The Department of Health and Human Services will launch an effort to create sustainable and resilient hospitals in the face of climate change. Through a public-private partnership with the healthcare industry, it will identify best practices and provide guidance on affordable measures to ensure that our medical system is resilient to climate impacts. It will also collaborate with partner agencies to share best practices among federal health facilities. And, building on lessons from pilot projects underway in 16 states, it will help train public-health professionals and community leaders to prepare their communities for the health consequences of climate change, including through effective communication of health risks and resilience measures.

Promoting Insurance Leadership for Climate Safety: Recognizing the critical role that the private sector plays in insuring assets and enabling rapid recovery after disasters, the Administration will convene representatives from the insurance industry and other stakeholders to explore best practices for private and public insurers to manage their own processes and investments to account for climate change risks and incentivize policy holders to take steps to reduce their exposure to these risks.

Conserving Land and Water Resources: America's ecosystems are critical to our nation's economy and the lives and health of our citizens. These natural resources can also help ameliorate the impacts of climate change, if they are properly protected. The Administration has invested significantly in conserving relevant ecosystems, including working with Gulf State partners after the Deepwater Horizon spill to enhance barrier islands and marshes that protect communities from severe storms. The Administration is also implementing climate-adaptation strategies that promote resilience in fish and wildlife populations, forests and other plant communities, freshwater resources, and the ocean. Building on these efforts, the President is also directing federal agencies to identify and evaluate additional approaches to improve our natural defenses against extreme weather, protect biodiversity and conserve natural resources in the face of a changing climate, and manage our public lands and natural systems to store more carbon.

Maintaining Agricultural Sustainability: Building on the existing network of federal climate-science research and action centers, the Department of Agriculture is creating seven new Regional Climate Hubs to deliver tailored, science-based knowledge to farmers, ranchers, and forest landowners. These hubs will work with universities and other partners, including the Department of the Interior and the National Oceanic and Atmospheric Administration, to support climate resilience. Its Natural Resources Conservation Service and the Department of the Interior's Bureau of Reclamation are also providing grants and technical support to agricultural water users for more water-efficient practices in the face of drought and long-term climate change.

Managing Drought: Leveraging the work of the National Disaster Recovery Framework for drought, the Administration will launch a cross-agency National Drought Resilience Partnership as a "front door" for communities seeking help to prepare for future droughts and reduce drought impacts. By linking information (monitoring, forecasts, outlooks, and early warnings) with drought preparedness and longer-term resilience strategies in critical sectors, this effort will help communities manage drought-related risks.

Reducing Wildfire Risks: With tribes, states, and local governments as partners, the Administration has worked to make landscapes more resistant to wildfires, which are exacerbated by heat and drought conditions resulting from climate change. Federal agencies will expand and prioritize forest and rangeland restoration efforts in order to make natural areas and communities less vulnerable to catastrophic fire. The Department of the Interior and Department of Agriculture, for example, are launching a Western Watershed Enhancement Partnership – a pilot effort in five western states to reduce wildfire risk by removing extra brush and other flammable vegetation around critical areas such as water reservoirs.

Preparing for Future Floods: To ensure that projects funded with taxpayer dollars last as long as intended, federal agencies will update their flood-risk reduction standards for federally funded projects to reflect a consistent approach that accounts for sea-level rise and other factors affecting flood risks. This effort will incorporate the most recent science on expected rates of sea-level rise (which vary by region) and build on work done by the Hurricane Sandy Rebuilding Task Force, which announced in April 2013 that all federally funded Sandy-related rebuilding projects must meet a consistent flood risk reduction standard that takes into account increased risk from extreme weather events, sea-level rise, and other impacts of climate change.

III. Using Sound Science to Manage Climate Impacts

Scientific data and insights are essential to help government officials, communities, and businesses better understand and manage the risks associated with climate change. The Administration will continue to lead in advancing the science of climate measurement and adaptation and the development of tools for climate-relevant decision-making by focusing on increasing the availability, accessibility, and utility of relevant scientific tools and information. Specific actions will include:

Developing Actionable Climate Science: The President's Fiscal Year 2014 Budget provides more than $2.7 billion, largely through the 13-agency U.S. Global Change Research Program, to increase understanding of climate-change impacts, establish a public-private partnership to explore risk and catastrophe modeling, and develop the information and tools needed by decision-makers to respond to both long-term climate change impacts and near-term effects of extreme weather.

Assessing Climate-Change Impacts in the United States: In the spring of 2014, the Obama Administration will release the third U.S. National Climate Assessment, highlighting new advances in our understanding of climate-change impacts across all regions of the United States and on critical sectors of the economy, including transportation, energy, agriculture, and ecosystems and biodiversity. For the first time, the National Climate Assessment will focus not only on dissemination of scientific information but also on translating scientific insights into practical, useable knowledge that can help decision-makers anticipate and prepare for specific climate-change impacts.

Launching a Climate Data Initiative: Consistent with the President's May 2013 Executive Order on Open Data – and recognizing that freely available open government data can fuel entrepreneurship, innovation, scientific discovery, and public benefits – the Administration is launching a Climate Data Initiative to leverage extensive federal climate-relevant data to stimulate innovation and private-sector entrepreneurship in support of national climate-change preparedness.

Providing a Toolkit for Climate Resilience: Federal agencies will create a virtual climate-resilience toolkit that centralizes access to data-driven resilience tools, services, and best practices, including those developed through the Climate Data Initiative. The toolkit will provide easy access to existing resources as well as new tools, including: interactive sea-level rise maps and a sea-level-rise calculator to aid post-Sandy rebuilding in New York and New Jersey, new NOAA storm surge models and interactive maps from the National Oceanic and Atmospheric Administration that provide risk information by combining tidal data, projected sea levels and storm wave heights, a web-based tool that will allow developers to integrate NASA climate imagery into websites and mobile apps, access to the U.S. Geological Survey's "visualization tool" to assess the amount of carbon absorbed by landscapes, and a Stormwater Calculator and Climate Assessment Tool developed to help local governments assess stormwater-control measures under different precipitation and temperature scenarios.

LEAD INTERNATIONAL EFFORTS TO ADDRESS GLOBAL CLIMATE CHANGE

The Obama Administration is working to build on the actions that it is taking domestically to achieve significant global greenhouse gas emission reductions and enhance climate preparedness through major international initiatives focused on spurring concrete action, including bilateral initiatives with China, India, and other major emitting countries. These initiatives not only serve to support the efforts of the United States and others to achieve our goals for 2020, but also will help us move beyond those and bend the post-2020 global emissions trajectory further. As a key part of this effort, we are also working intensively to forge global responses to climate change through a number of important international negotiations, including the United Nations Framework Convention on Climate Change.

I. Working with Other Countries to Take Action to Address Climate Change

Enhancing Multilateral Engagement with Major Economies: In 2009, President Obama launched the Major Economies Forum on Energy and Climate, a high-level forum that brings together 17 countries that account for approximately 75 percent of global greenhouse gas emissions, in order to support the international climate negotiations and spur cooperative action to combat climate change. The Forum has been successful on both fronts – having contributed significantly to progress in the broader negotiations while also launching the Clean Energy Ministerial to catalyze the development and deployment of clean energy and efficiency solutions. We are proposing that the Forum build on these efforts by launching a major initiative this year focused on further accelerating efficiency gains in the buildings sector, which accounts for approximately one-third of global carbon pollutions from the energy sector.

Expanding Bilateral Cooperation with Major Emerging Economies:
From the outset, the Obama Administration has sought to intensify bilateral climate cooperation with key major emerging economies, through initiatives like the U.S.-China Clean Energy Research Center, the U.S.-India Partnership to Advance Clean Energy, and the Strategic Energy Dialogue with Brazil.

We will be building on these successes and finding new areas for cooperation in the second term, and we are already making progress: Just this month, President Obama and President Xi Jinping of China reached an historic agreement at their first summit to work to use the expertise and institutions of the Montreal Protocol to phase down the consumption and production of HFCs, a highly potent greenhouse gas. The impact of phasing out HFCs by 2050 would be equivalent to the elimination of two years' worth of greenhouse gas emissions from all sources.

Combatting Short-Lived Climate Pollutants: Pollutants such as methane, black carbon, and many HFCs are relatively short-lived in the atmosphere, but have more potent greenhouse effects than carbon dioxide. In February 2012, the United States launched the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollution, which has grown to include more than 30 country partners and other key partners such as the World Bank and the U.N. Environment Programme. Major efforts include reducing methane and black carbon from waste and landfills. We are also leading through the Global Methane Initiative, which works with 42 partner countries and an extensive network of over 1,100 private sector participants to reduce methane emissions.

<u>Reducing Emissions from Deforestation and Forest Degradation:</u> Greenhouse gas emissions from deforestation, agriculture, and other land use constitute approximately one-third of global emissions. In some developing countries, as much as 80 percent of these emissions come from the land sector. To meet this challenge, the Obama Administration is working with partner countries to put in place the systems and institutions necessary to significantly reduce global land-use-related emissions, creating new models for rural development that generate climate benefits, while conserving biodiversity, protecting watersheds, and improving livelihoods.

In 2012 alone, the U.S. Agency for International Development's bilateral and regional forestry programs contributed to reducing more than 140 million tons of carbon dioxide emissions, including through support for multilateral initiatives such as the Forest Investment Program and the Forest Carbon Partnership Facility. In Indonesia, the Millennium Challenge Corporation is funding a five-year "Green Prosperity" program that supports environmentally sustainable, low carbon economic development in select districts.

The Obama Administration is also working to address agriculture-driven deforestation through initiatives such as the Tropical Forest Alliance 2020, which brings together governments, the private sector, and civil society to reduce tropical deforestation related to key agricultural commodities, which we will build upon.

<u>Expanding Clean Energy Use and Cut Energy Waste:</u> Roughly 84 percent of current carbon dioxide emissions are energy-related and about 65 percent of all greenhouse gas emissions can be attributed to energy supply and energy use. The Obama Administration has promoted the expansion of renewable, clean, and efficient energy sources and technologies worldwide through:

- Financing and regulatory support for renewable and clean energy projects
- Actions to promote fuel switching from oil and coal to natural gas or renewables
- Support for the safe and secure use of nuclear power
- Cooperation on clean coal technologies
- Programs to improve and disseminate energy efficient technologies

In the past three years we have reached agreements with more than 20 countries around the world, including Mexico, South Africa, and Indonesia, to support low emission development strategies that help countries to identify the best ways to reduce greenhouse gas emissions while growing their economies. Among the many initiatives that we have launched are:

- The U.S. Africa Clean Energy Finance Initiative, which aligns grant-based assistance with project planning expertise from the U.S. Trade and Development Agency and financing and risk mitigation tools from the U.S. Overseas Private Investment Corporation to unlock up to $1 billion in clean energy financing.

- The U.S.-Asia Pacific Comprehensive Energy Partnership, which has identified $6 billion in U.S. export credit and government financing to promote clean energy development in the Asia-Pacific region.

Looking ahead, we will target these and other resources towards greater penetration of renewables in the global energy mix on both a small and large scale, including through our participation in the Sustainable Energy for All Initiative and accelerating the commercialization of renewable mini-grids. These efforts include:

- **Natural Gas.** Burning natural gas is about one-half as carbon-intensive as coal, which can make it a critical "bridge fuel" for many countries as the world transitions to even cleaner sources of energy. Toward that end, the Obama Administration is partnering with states and private companies to exchange lessons learned with our international partners on responsible development of natural gas resources. We have launched the Unconventional Gas Technical Engagement Program to share best practices on issues such as water management, methane emissions, air quality, permitting, contracting, and pricing to help increase global gas supplies and facilitate development of the associated infrastructure that brings them to market. Going forward, we will promote fuel-switching from coal to gas for electricity production and encourage the development of a global market for gas. Since heavy-duty vehicles are expected to account for 40 percent of increased oil use through 2030, we will encourage the adoption of heavy duty natural gas vehicles as well.

- **Nuclear Power.** The United States will continue to promote the safe and secure use of nuclear power worldwide through a variety of bilateral and multilateral engagements. For example, the U.S. Nuclear Regulatory Commission advises international partners on safety and regulatory best practices, and the Department of Energy works with international partners on research and development, nuclear waste and storage, training, regulations, quality control, and comprehensive fuel leasing options. Going forward, we will expand these efforts to promote nuclear energy generation consistent with maximizing safety and nonproliferation goals.

- **Clean Coal.** The United States works with China, India, and other countries that currently rely heavily on coal for power generation to advance the development and deployment of clean coal technologies. In addition, the U.S. leads the Carbon Sequestration Leadership Forum, which engages 23 other countries and economies on carbon capture and sequestration technologies. Going forward, we will continue to use these bilateral and multilateral efforts to promote clean coal technologies.

- **Energy Efficiency.** The Obama Administration has aggressively promoted energy efficiency through the Clean Energy Ministerial and key bilateral programs. The cost-effective opportunities are enormous: The Ministerial' s Super-Efficient Equipment and Appliance Deployment Initiative and its Global Superior Energy Performance Partnership are helping to accelerate the global adoption of standards and practices that would cut energy waste equivalent to more than 650 mid-size power plants by 2030. We will work to expand these efforts focusing on several critical areas, including: improving building efficiency, reducing energy consumption at water and wastewater treatment facilities, and expanding global appliance standards.

Negotiating Global Free Trade in Environmental Goods and Services: The U.S. will work with trading partners to launch negotiations at the World Trade Organization towards global free trade in environmental goods, including clean energy technologies such as solar, wind, hydro and geothermal. The U.S. will build on the consensus it recently forged among the 21 Asia-Pacific Economic Cooperation (APEC) economies in this area. In 2011, APEC economies agreed to reduce tariffs to 5 percent or less by 2015 on a negotiated list of 54 environmental goods. The

APEC list will serve as a foundation for a global agreement in the WTO, with participating countries expanding the scope by adding products of interest. Over the next year, we will work towards securing participation of countries which account for 90 percent of global trade in environmental goods, representing roughly $481 billion in annual environmental goods trade. We will also work in the Trade in Services Agreement negotiations towards achieving free trade in environmental services.

Phasing Out Subsidies that Encourage Wasteful Consumption of Fossil Fuels: The International Energy Agency estimates that the phase-out of fossil fuel subsidies – which amount to more than $500 billion annually – would lead to a 10 percent reduction in greenhouse gas emissions below business as usual by 2050. At the 2009 G-20 meeting in Pittsburgh, the United States successfully advocated for a commitment to phase out these subsidies, and we have since won similar commitments in other fora such as APEC. President Obama is calling for the elimination of U.S. fossil fuel tax subsidies in his Fiscal Year (FY) 2014 budget, and we will continue to collaborate with partners around the world toward this goal.

Leading Global Sector Public Financing Towards Cleaner Energy: Under this Administration, the United States has successfully mobilized billions of dollars for clean energy investments in developing countries, helping to accelerate their transition to a green, low-carbon economy. Building on these successes, the President calls for an end to U.S. government support for public financing of new coal plants overseas, except for (a) the most efficient coal technology available in the world's poorest countries in cases where no other economically feasible alternative exists, or (b) facilities deploying carbon capture and sequestration technologies. As part of this new commitment, we will work actively to secure the agreement of other countries and the multilateral development banks to adopt similar policies as soon as possible.

Strengthening Global Resilience to Climate Change: Failing to prepare adequately for the impacts of climate change that can no longer be avoided will put millions of people at risk, jeopardizing important development gains, and increasing the security risks that stem from climate change. That is why the Obama Administration has made historic investments in bolstering the capacity of countries to respond to climate-change risks. Going forward, we will continue to:

- Strengthen government and local community planning and response capacities, such as by increasing water storage and water use efficiency to cope with the increased variability in water supply

- Develop innovative financial risk management tools such as index insurance to help smallholder farmers and pastoralists manage risk associated with changing rainfall patterns and drought

- Distribute drought-resistant seeds and promote management practices that increase farmers' ability to cope with climate impacts.

Mobilizing Climate Finance: International climate finance is an important tool in our efforts to promote low-emissions, climate-resilient development. We have fulfilled our joint developed country commitment from the Copenhagen Accord to provide approximately $30 billion of climate assistance to developing countries over FY 2010-FY 2012. The United States contributed approximately $7.5 billion to this effort over the three year period. Going forward, we will seek to build on this progress as well as focus our efforts on combining our public resources with smart policies to mobilize much larger flows of private investment in low-emissions and climate resilient infrastructure.

II. Leading Efforts to Address Climate Change through International Negotiations

The United States has made historic progress in the international climate negotiations during the past four years. At the Copenhagen Conference of the United Nations Framework Convention on Climate Change (UNFCCC) in 2009, President Obama and other world leaders agreed for the first time that all major countries, whether developed or developing, would implement targets or actions to limit greenhouse emissions, and do so under a new regime of international transparency. And in 2011, at the year-end climate meeting in Durban, we achieved another breakthrough: Countries agreed to negotiate a new agreement by the end of 2015 that would have equal legal force and be applicable to all countries in the period after 2020. This was an important step beyond the previous legal agreement, the Kyoto Protocol, whose core obligations applied to developed countries, not to China, India, Brazil or other emerging countries.
The 2015 climate conference is slated to play a critical role in defining a post-2020 trajectory. We will be seeking an agreement that is ambitious, inclusive and flexible. It needs to be ambitious to meet the scale of the challenge facing us. It needs to be inclusive because there is no way to meet that challenge unless all countries step up and play their part. And it needs to be flexible because there are many differently situated parties with their own needs and imperatives, and those differences will have to be accommodated in smart, practical ways.

At the same time as we work toward this outcome in the UNFCCC context, we are making progress in a variety of other important negotiations as well. At the Montreal Protocol, we are leading efforts in support of an amendment that would phase down HFCs; at the International Maritime Organization, we have agreed to and are now implementing the first-ever sector-wide, internationally applicable energy efficiency standards; and at the International Civil Aviation Organization, we have ambitious aspirational emissions and energy efficiency targets and are working towards agreement to develop a comprehensive global approach.

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

METHANOL TANK EXPLOSION AND FIRE

(2 Dead, 1 Critically Injured)

BETHUNE POINT WASTEWATER TREATMENT PLANT

CITY OF DAYTONA BEACH, FLORIDA

JANUARY 11, 2006

KEY ISSUES:

- HAZARD COMMUNICATION
- HOT WORK CONTROL
- PLASTIC PIPE IN FLAMMABLE SERVICE
- FLAME ARRESTER MAINTENANCE
- FLORIDA PUBLIC EMPLOYEE SAFETY PROGRAMS

REPORT NO. 2006-03-I-FL

MARCH 2007

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Acronyms and Abbreviations

ASME	American Society of Mechanical Engineers
BNR	Biological Nutrient Removal
BOCA	Building Officials Code Administrators
CDM	Camp Dresser & McKee Inc.
CFR	Code of Federal Regulations
CSB	U. S. Chemical Safety and Hazard Investigation Board
FAC	Florida Administrative Code
HAZCOM	Hazard Communication
IRIC	Indian River Industrial Contractors
MSDS	Material Safety Data Sheet
NACE	National Association of Corrosion Engineers
NFPA	National Fire Protection Association
NPS	Nominal Pipe Size
OJT	On-the-Job Training
OSHA	Occupational Safety and Health Administration
pH	Hydrogen Ion Concentration
PVC	Polyvinyl Chloride
SCBA	Self Contained Breathing Apparatus
WEF	Water Environment Federation
WWTP	Wastewater Treatment Plant

Executive Summary

On January 11, 2006, an explosion and fire occurred at the City of Daytona Beach, Bethune Point Wastewater Treatment Plant (Bethune Point WWTP) in Daytona Beach, Florida, killing two employees and severely burning a third.

The Bethune Point WWTP processes wastewater using a treatment that requires the addition of methanol, a highly flammable liquid. The methanol is stored in an aboveground storage tank.

The U.S. Chemical Safety and Hazard Investigation Board (CSB) determined that maintenance workers using a cutting torch on a roof above the methanol storage tank accidentally ignited vapors coming from the tank vent. The flame flashed back into the storage tank, causing an explosion inside the tank that precipitated multiple methanol piping failures and a large fire that engulfed the tank and workers.

The investigation identified the following root causes:

The City of Daytona Beach

- did not implement adequate controls for hot work at the Bethune Point WWTP, and
- had a hazard communication program that did not effectively communicate the hazards associated with methanol at the Bethune Point WWTP.

The investigation identified the following contributing causes:

- The City of Daytona Beach has no program to evaluate the safety of non-routine tasks.
- The piping and valves in the methanol system were constructed of polyvinyl chloride in lieu of steel.

- An aluminum flame arrester was installed on the methanol tank vent even though methanol corrodes aluminum.
- The operation and maintenance manual for the Bethune Point WWTP did not include a requirement to maintain the flame arrester.

This CSB report makes recommendations to the Governor and Legislature of the State of Florida; the City of Daytona Beach; the U.S. Department of Labor, Occupational Safety and Health Administration; the National Fire Protection Association; the Water Environment Federation; the Methanol Institute; and Camp Dresser & McKee Inc.

1.0 INTRODUCTION

1.1 Background

On January 11, 2006, an explosion and fire occurred at the City of Daytona Beach, Bethune Point WWTP in Daytona Beach, Florida. Two employees died and one was severely burned after a worker using a cutting torch accidentally ignited vapors coming from the methanol storage tank vent. An explosion inside the tank followed, causing the attached piping to fail and release about 3,000 gallons of methanol, which burned.

1.2 Investigative Process

Investigators from the U.S. Chemical Safety and Hazard Investigation Board (CSB) arrived at the facility on January 13, 2006. The CSB examined and collected physical evidence from the incident, interviewed Bethune WWTP employees and others, and reviewed relevant documents. The CSB coordinated its work with a number of other investigative organizations, including:

- Division of the State Fire Marshal, State of Florida;
- City of Daytona Beach Police Department; and
- City of Daytona Beach Fire Department.

1.3 City of Daytona Beach

The City of Daytona Beach, located on the east coast of central Florida in Volusia County, has about 64,000 residents and is governed by a city commission composed of a mayor and six elected commissioners. The commission hires a city manager who presents a budget for the commission's approval, oversees city operations, and manages about 800 city employees.

The Bethune Point WWTP is part of the Waste/Water group in the Utilities department, whose director reports to the city manager.

1.4 Bethune Wastewater Treatment Plant

Eleven city employees operate the Bethune Point WWTP, treating about 13 million gallons per day before discharging to the Halifax River (Figure 1).

Figure 1. Bethune Point WWTP.
(Picture courtesy of the City of Daytona Beach)

The plant originally used conventional wastewater treatment. This treatment is appropriate for the wastewater that Bethune Point receives, but is ineffective at removing nitrogen and phosphorus compounds that promote algae growth.

In the late 1980s, the State of Florida required wastewater treatment plants to reduce the discharge of compounds that promote algae growth. The City of Daytona Beach contracted Camp Dresser & McKee Inc.[1] (CDM) in 1989 to redesign the Bethune Point plant to incorporate an advanced wastewater treatment process to remove nitrogen and phosphorus compounds. CDM's scope of work was to specify the process, develop the conceptual and detailed designs, prepare construction and project specifications, and oversee construction. The City of Daytona Beach separately contracted Indian River Industrial Contractors (IRIC) to build the advanced wastewater treatment process. Operation of the new process started in 1993.

1.5 Advanced Wastewater Treatment Process

Advanced wastewater treatment is a biological nutrient removal (BNR) process where specialized bacteria, with the addition of an organic nutrient, convert nitrogen compounds into nitrogen gas. The Bethune Point WWTP uses methanol as the organic nutrient for the bacteria. Chemical metering pumps continuously fed methanol to the process from a 10,000-gallon carbon steel storage tank.

In 1999, the City of Daytona Beach modified the BNR process to operate without the continuous methanol feed; however, the facility continued to use the methanol system and 10,000-gallon storage tank for sporadic methanol addition. As a result, the facility maintained a large inventory of methanol even though demand was substantially reduced. The methanol storage tank contained between 2,000 and 3,000 gallons when the incident occurred.

[1] CDM is a multinational consulting, engineering, and construction firm specializing in water and wastewater treatment facilities.

1.6 Methanol

Methanol (commonly known as methyl or wood alcohol) is a Class 1B flammable liquid with a flash point of 54ºF (12ºC); its explosive limits are 6 to 36.5 volume percent in air. Methanol vapors are heavier than air with a vapor density (air=1) of 1.1.[2]

Methanol vapors burn with a colorless flame in daylight, although the presence of other materials can color the flame. Methanol is a skin and eye irritant and highly toxic when ingested.[3]

In addition to wastewater treatment, methanol is used in the manufacture of numerous consumer products including plastics, paints, adhesives, and fuels.[4]

The Methanol Institute represents manufacturers of methanol and distributes health, safety, and environmental information on the use and distribution of methanol.

1.7 Water Environment Federation

The Water Environment Federation (WEF) is a not-for-profit technical and educational organization with members from the wastewater industry. WEF offers training programs, workshops, and seminars. In addition, WEF publishes technical manuals and other information for the wastewater industry.

[2] Lewis, R., 2000. *Sax's Dangerous Properties of Industrial Materials* (10th Edition).
[3] Ibid.
[4] Methanol Institute website, 2006, www.methanol.org.

2.0 Incident Description

2.1 Pre-Incident Events

In 2004 and 2005, several hurricanes damaged the Bethune Point WWTP, including two metal roofs used to shade two chemical storage areas. Facility personnel removed one of the damaged metal roofs in 2005 without incident. The second metal roof, installed over the methanol storage tank, was about 30 feet above the ground and more difficult to access. In consultation with the facility superintendent, the lead mechanic determined that facility personnel could remove the second damaged metal roof using a city-owned crane and a rented man-lift. The lead mechanic planned the job to remove the metal roof. The facility superintendent did not review details of the job and possible hazards.

On Monday, January 9, 2006, the lead mechanic and a mechanic prepared to remove the metal roof. They retrieved the man-lift and crane from other city facilities. The lead mechanic then familiarized himself with the operation of the man-lift. Workers at the Bethune Point WWTP had previously used the city crane and were familiar with its operation.

On Tuesday, January 10, 2006, the lead mechanic, the mechanic, and a third worker began removing the metal roof over the methanol storage tank. Standing in the man-lift, the lead mechanic and mechanic cut the metal roof into sections with an oxy-acetylene cutting torch and attached the cut sections to the crane hook. The third worker operated the crane to lower the cut sections to the ground. While cutting the metal roof, sparks from the torch ignited a grass fire. The crane operator extinguished the grass fire with a garden hose. In the early afternoon, the workers ran out of oxygen for the cutting torch and stopped work for the day. The lead mechanic ordered another oxygen cylinder so the job could resume on Wednesday.

2.2 The Incident

On Wednesday, January 11, 2006, three workers[5] continued the roof removal. About 11:15 a.m., the lead mechanic and the third worker were cutting the metal roof directly above the methanol tank vent. Sparks, showering down from the cutting torch, ignited methanol vapors coming from the vent, creating a fireball on top of the tank. The fire flashed through a flame arrester on the vent, igniting methanol vapors and air inside the tank, causing a explosion inside the steel tank. Figure 2 is an overview of the accident site showing the crane, man-lift, and tank after the incident.

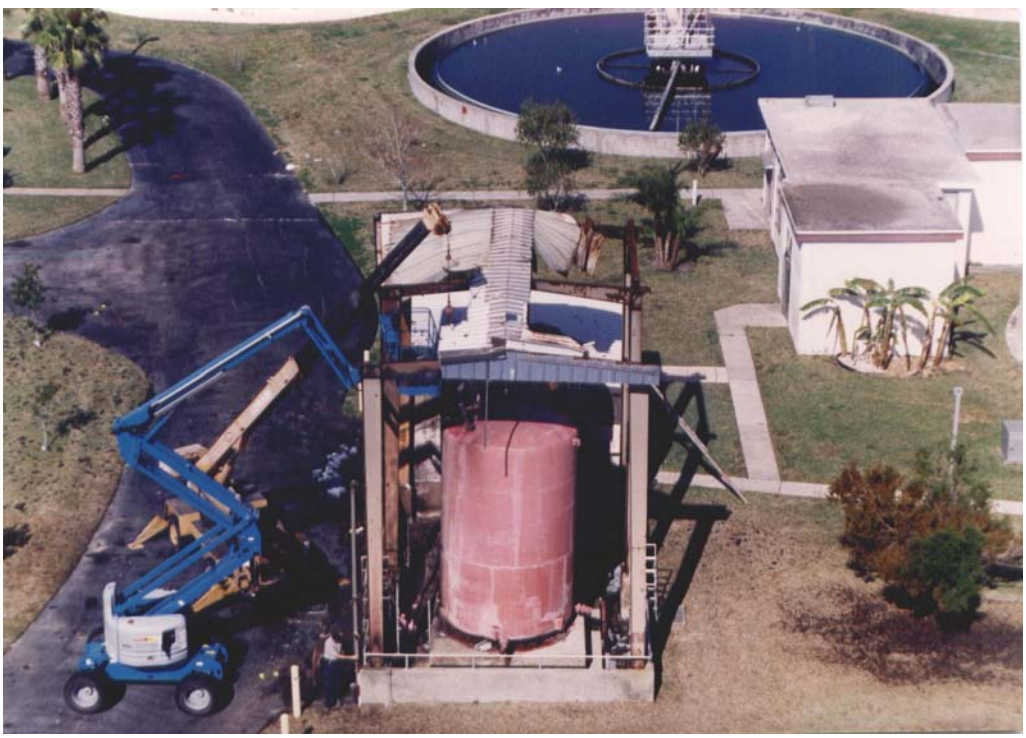

Figure 2. Bethune Point WWTP accident site.

(Picture courtesy of the City of Daytona Beach)

[5] The workers included the lead mechanic and mechanic who worked on January 9 and 10, 2006 and a new worker from the facility.

The explosion inside the methanol storage tank

- rounded the tank's flat bottom, permanently deforming the tank and raising the side wall about one foot;
- ripped the nuts from six bolts used to anchor the tank to a concrete foundation;
- blew the flame arrester off the tank vent pipe;
- blew a level sensor off a 4-inch flange on the tank top;
- separated two 1-inch pipes, valves, and an attached level switch from flanges on the side of the tank;
- separated a 4-inch tank outlet pipe from the tank outlet valve; and
- separated a 4-inch tank fill pipe near the top the tank.

Methanol discharged from the separated pipes ignited and burned, spreading the fire. Methanol also flowed into the containment around the tank and through a drain to the WWTP where it was diluted and harmlessly processed.

The lead mechanic and the third worker were in the man-lift basket over the methanol tank when the ignition occurred. They were likely burned from the initial fireball and burning methanol vapors discharging from the tank vent under pressure from the explosion. The lead mechanic, fully engulfed in fire, likely jumped or fell from the man-lift. Emergency responders found his body within the concrete containment next to the tank.

The third worker stated that he had been partially out of the man-lift basket leaning over the roof when the fire ignited. On fire, he climbed onto the roof to escape. Co-workers, unable to reach him with a ladder, told him to jump to an adjacent lower roof and then to the ground. He sustained second- and third-degree burns over most of his body, and was hospitalized for 4 months before being released to a medical rehabilitation facility.

Methanol sprayed from separated pipes onto the crane, burning the crane cab with the mechanic inside. On fire, he exited the cab and was assisted by co-workers. He died in the hospital the following day.

2.3 Emergency Response

Bethune Point WWTP workers heard the explosion and immediately went to the scene of the fire and aided the victims. The facility superintendent and a facility operator called 911 to report the incident and request fire and medical assistance. City Fire Station # 1 dispatched the first unit at 11:18 a.m., which arrived at Bethune Point WWTP at 11:22 a.m. When the unit arrived, the methanol and an adjacent empty tank were fully involved in the fire.

Firefighters provided first aid to the two burn victims and set up a fire monitor to provide a continuous stream of water onto burning insulation on the adjacent tank. Firefighters then evacuated everyone to an assembly point outside the main gate. The Volusia County Hazardous Materials (HAZMAT) Team also responded and assumed control of the firefighting effort. Firefighters extinguished the fire later that afternoon. The HAZMAT Team emergency responders recovered the body of the first victim the following day.

In addition to the three victims of the fire, 14 people sought medical evaluation. They included nine firefighters, four Bethune Point WWTP employees, and one police officer. After evaluation, one firefighter was transported to the hospital, treated, and released. There were no off-site consequences from this incident.

3.0 Analysis

The following sections analyze several causes CSB identified (Appendix A) including

- a lack of methanol hazard recognition;
- a lack of safety and hazard review in job planning;
- methanol piping failure; and
- an ineffective flame arrester.

3.1 Chemical Hazard Recognition

Chemical hazard recognition is commonly addressed through a hazard communication (HAZCOM) program that provides employees with information on chemical hazards and trains them on specific hazards and the use of available information. OSHA standards[6] require HAZCOM programs, however the City of Daytona Beach is not required to comply with these standards (Section 4.0). Although not required by regulation, the City of Daytona Beach maintains and makes available written information on chemical hazards and conducts safety and HAZCOM training.

As part of the investigation, the CSB analyzed Bethune Point WWTP employee continuing training records for safety and HAZCOM for 12 years preceding the incident; Table 1 lists these safety training topics. Of these, the City offered HAZCOM (also known as Right-to-Know) training only seven times and not since 2002. OSHA standards require employers to conduct HAZCOM training annually.

[6] 29 CFR Part 1910, Occupational Safety and Health Standards.

Table 1. Bethune Point WWTP safety training classes from 1994-2005.

Safety Training Topic	Sessions Conducted	Last Year Conducted
Gas Detector	2	2005
Lockout Tagout	3	2004
Self Contained Breathing Apparatus (SCBA)	11	2003
Fire Extinguisher	1	2003
Confined Space	2	2002
Right-to-Know – Material Safety Data Sheets (HAZCOM)	7	2002
Heat Exhaustion - Hot Environment	3	2001
Blood Borne Pathogens	2	2000
Fall Arrester	2	2000
Ultra Violet Lamps	1	2000
Uninterruptible Power Supply	1	2000
Air Pac (SCBA)	6	1999
Process Hazard Analysis Team Meeting	1	1998
Vehicular safety	1	1997
Fire Safety	1	1997
Foot Protection Awareness	1	1997
Entry Retrieval System	1	1996
Back Safety	1	1995

The city used a variety of training resources, including the Daytona Beach Fire Department; private contractors; equipment suppliers; and city personnel.

The contract for the 1993 plant upgrade that added the methanol system included a requirement for staff training; however, a detailed record of this training was unavailable. While a training abstract found in the contract files listed training topics, the CSB could not determine from this abstract if the methanol storage tank, flame arrester, and methanol hazards were covered. Interviewed employees remembered some methanol system training in 1993, but none could identify the purpose of the flame arrester or how the tank vented. In addition, employees could not remember if any of the HAZCOM (Right-to-Know) training sessions covered methanol hazards.

Up to calendar year 2000, the City offered an average of five safety-related training sessions at Bethune Point WWTP each year; however, since 2000 the number of such sessions[7] declined steadily (Figure 3). This decline may have been influenced by the repeal of the Florida public employee safety law (2000) and the elimination of City of Daytona Beach full-time Safety Position (2004).

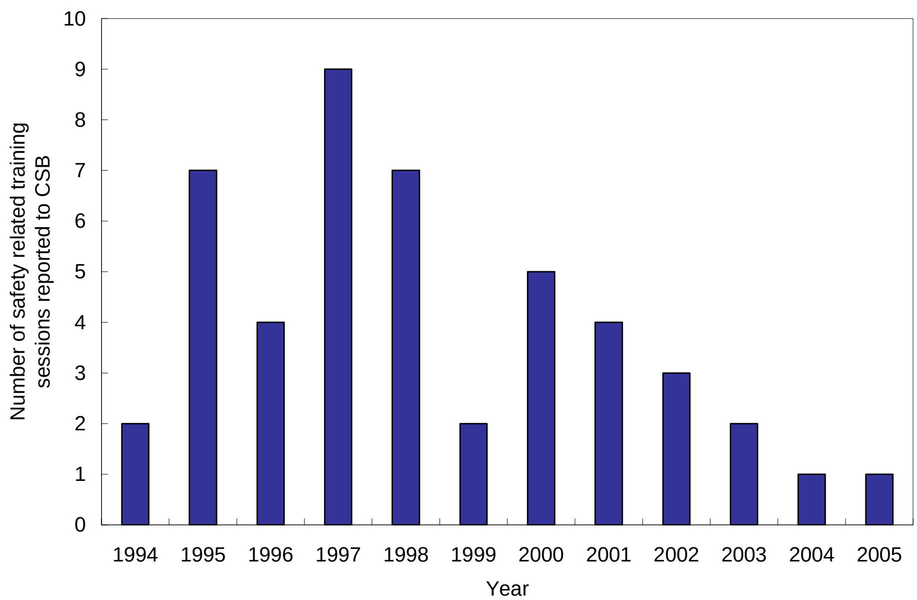

Figure 3. Bethune Point WWTP safety related training sessions.

In summary, the CSB found that the scope, content, and frequency of the HAZCOM training provided to Bethune Point WWTP employees did not adequately prepare them to deal with the hazards associated with flammable materials such as methanol.

[7] Many of the sessions were less than 1 hour in length.

3.2 Safety and Hazard Review in Job Planning

The CSB found that the City of Daytona Beach had not implemented a systematic method for identifying hazards during non-routine work,[8] nor did the City have a permit-to-work system. Non-routine tasks can be among the most hazardous at any facility. The lack of formal written procedures and general unfamiliarity with the work increase the risk of these tasks. A permit-to-work system is a widely used technique for evaluating hazards of non-routine work. Had the city used a permit-to-work system or other work control practice, this incident may have been prevented.

The objective of permit-to-work systems is to ensure that non-routine work is properly planned and authorized prior to commencing. Generally, a designated individual who is not the planner or executor of the work signs the permit authorizing the work to proceed. This individual is typically a supervisor, safety technician, or senior operator.

Permits can be issued to control any type of work, but those that are inherently hazardous are the most important. Lees (2001) and the Center for Chemical Process Safety (CCPS) (1995) list hazardous activities, including hot work[9], that especially warrant inclusion in a permit system

[8] Examples of non-routine work can include repairs, corrective maintenance, troubleshooting, and infrequent tasks.

[9] Hot work is defined as any work that may be a source of ignition, including open flames, cutting and welding, sparking of electrical equipment, grinding, buffing, drilling, chipping, sawing, or other similar operations that create hot metal sparks or hot surfaces from friction or impact.

3.3 Methanol Piping

3.3.1 Piping Design

CDM, the methanol system designer, specified[10] polyvinyl chloride (PVC) piping, valves, and fittings for all of the above- and below ground piping in the methanol system.

The aboveground PVC piping (Figure 4) included:

- a 4-inch nominal pipe size (NPS) fill pipe that connected a flange on the top of the tank to a fill connection near ground level;
- a 4-inch NPS outlet pipe, connected to a valve on a flange near the bottom of the tank that supplied the methanol pumps;
- two 1-inch NPS pipes and PVC valves that connected a level switch to two flanges near the bottom of the tank; and
- a 4-inch NPS vent pipe connected to a flange on the top of the tank to the flame arrester. The flame arrester end of this pipe was threaded.

[10] Bethune Point WWTP Facility Upgrade project specifications prepared by CDM, under contract to the City of Daytona Beach, section 11354, Methanol Feed System.

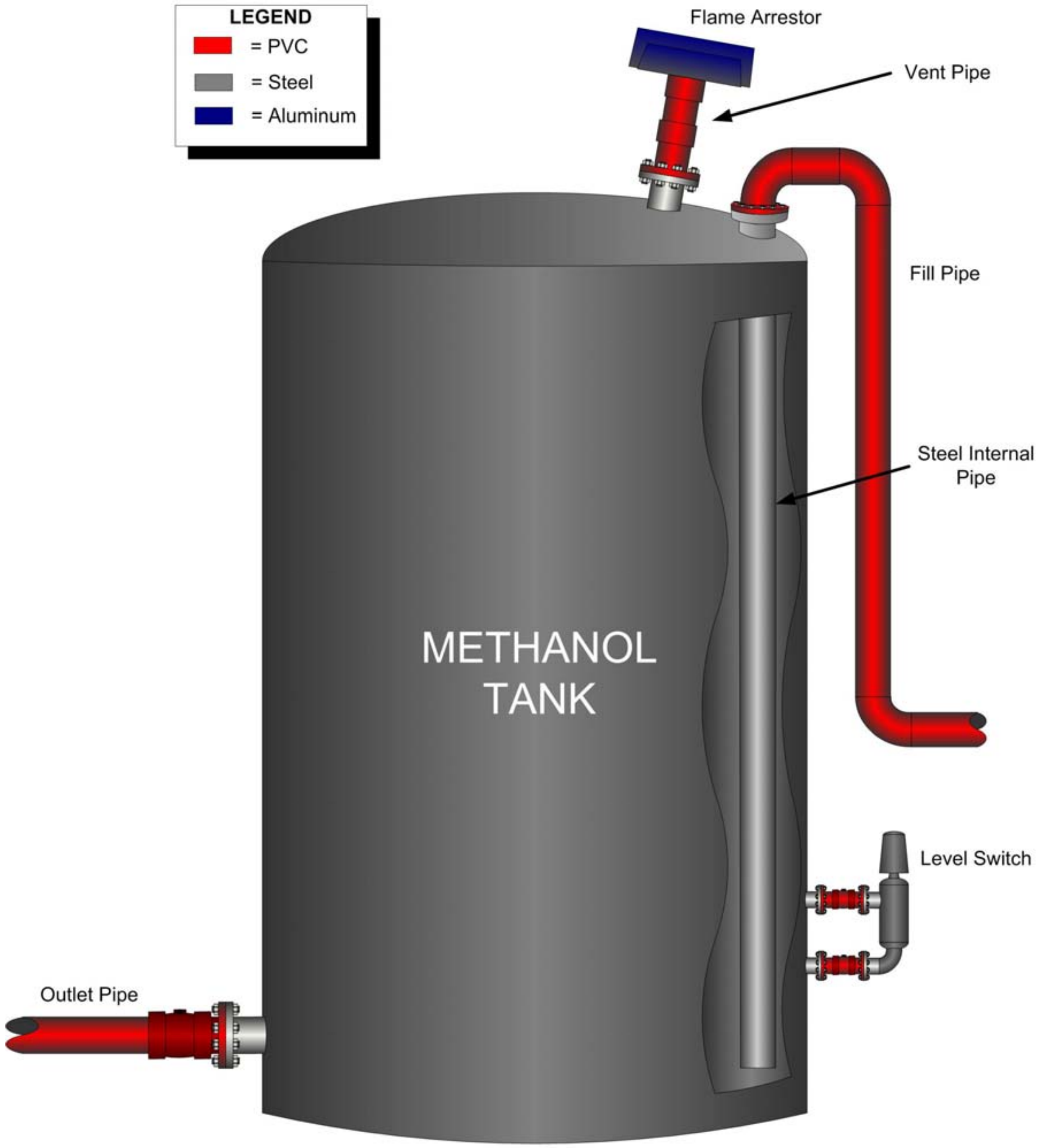

Figure 4. Aboveground PVC methanol pipes

3.3.2 Piping Specifications and Standards

The CDM methanol system specification[11] required that "[t]he entire system shall comply with all applicable OSHA rules and regulations." Therefore, OSHA standard 1910.106, "Flammable and Combustible Liquids," would have applied to this installation. This standard requires that all aboveground piping containing flammable liquids be steel, nodular iron, or malleable iron. The tensile strength and fracture toughness[12] of steel is more than ten times greater than the PVC plastic pipe used for the methanol system.

OSHA standard 1910.106 does allow materials that soften on fire exposure such as plastics, but only when "necessary." CDM stated[13] that it specified PVC for its compatibility with methanol and its ability to withstand the system pressure. The CSB noted that published corrosion data indicate that steel is compatible with methanol, that steel piping is widely used in flammable liquid systems, and that the methanol tank specified by CDM was made of steel. From this, the CSB concluded that no necessity to use PVC pipe existed.

The CDM methanol tank specification[14] required that the tank comply with National Fire Protection Association Standard (NFPA) 30, Flammable and Combustible Liquids Code (1990). NFPA 30 section 3-3.3 requires that all valves connected to storage tanks be steel. Despite this requirement, CDM

[11] Bethune Point WWTP Upgrade project specifications (idem).

[12] Fracture toughness is a measure of a materials ability to resist brittle failure.

[13] In response to an interrogatory in which the CSB asked CDM to describe the necessity for using PVC piping.

[14] Bethune WWTP Upgrade project specifications prepared by CDM, under contract to the City of Daytona Beach, section 13515, Methanol Chemical Storage Tank.

informed Indian River Industrial Contractor Inc. (IRIC), the facility constructor, that PVC ball valves could be used.[15]

Although NFPA 30 and OSHA standard 1910.106 permit plastic materials in aboveground flammable liquid systems under certain conditions, other widely recognized standards prohibit them. These include the American Society of Mechanical Engineers (ASME) Process Piping Code, ASME B31.3[16] and the Building Officials Code Administrators (BOCA) National Mechanical Code, Seventh Edition.[17]

3.3.3 Piping Failure

The physical evidence indicates that the PVC piping connected to the methanol tank mechanically failed in multiple locations from the upward movement of the tank caused by the internal explosion. This evidence includes:

- The burn pattern on the side of the tank, which most likely occurred when pressure from the internal explosion forced methanol up an internal pipe and sprayed it out of the separated fill pipe onto the side of the tank.

- The burn pattern on the ground east of the tank, which most likely occurred when pressure from the explosion sprayed methanol onto the ground through the failed outlet pipe connected near the bottom of the tank.

- Two PVC valves and a portion of the connected pipe found in the concrete containment that surrounded the tank. These valves and their associated PVC pipe and flanges were installed between

[15] CDM response to an IRIC request for information dated May 12, 1993.
[16] Chapter VII, Nonmetallic Piping and Piping Lined with Nonmetals, paragraph A323.4.2 (a) (1).
[17] Article 9, Flammable and Combustible Liquid Storage and Piping Systems, paragraph M-901.5.

steel flanges on the tank and steel flanges on the level switch. A recovered valve shows the fractured PVC pipe between the valve and flange (Figure 5).

Figure 5. Failed 1-inch PVC pipe showing fracture surface

- PVC material lodged in the threads of the flame arrester and visible damage to the threads on the end of the PVC vent pipe.

The two fractured PVC pipes supporting the level switch pointed directly toward the crane cab where the mechanic was sitting. Methanol discharging under pressure most likely sprayed the cab, ignited and seriously burned the mechanic inside. Figure 6 shows the burned-out cab aligned with the 1-inch pipe flanges on the tank.

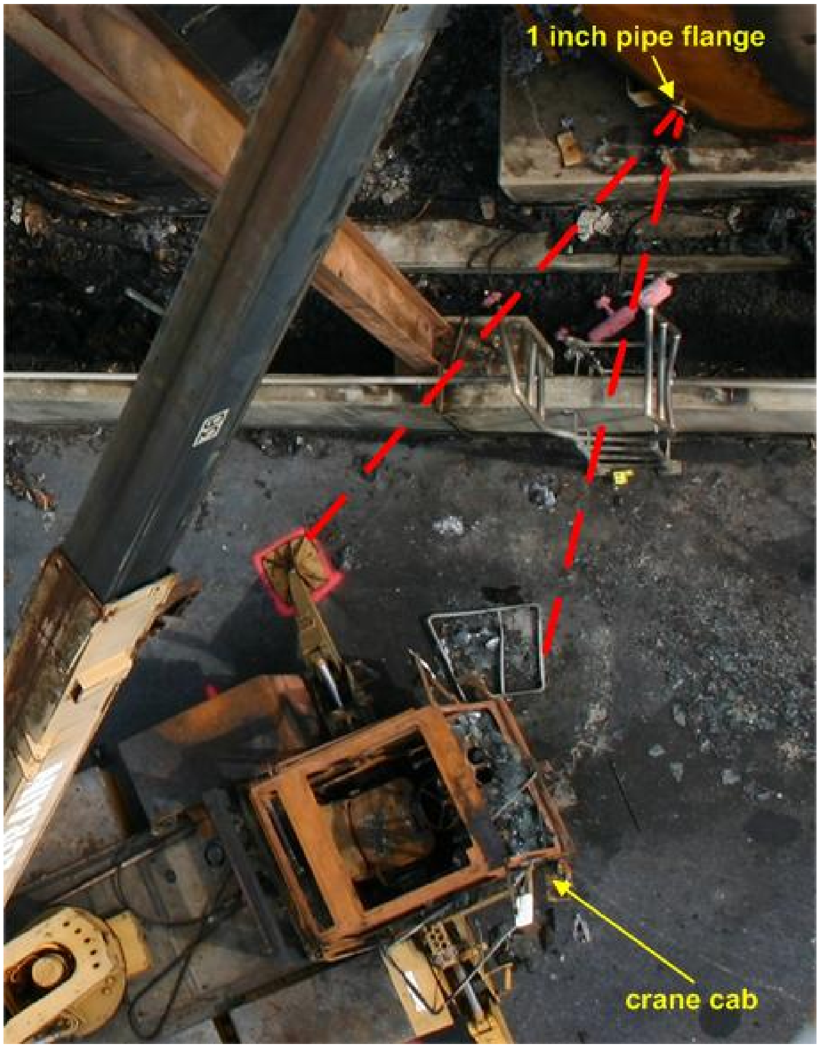

Figure 6. Methanol spray from 1-inch pipe flanges onto the crane cab.

The PVC vent pipe was below the man-lift basket. After the flame arrester blew off the vent pipe, burning methanol vapors under pressure would have likely discharged into the basket where two workers were standing. Figure 7 shows the location of the basket relative to the vent pipe.

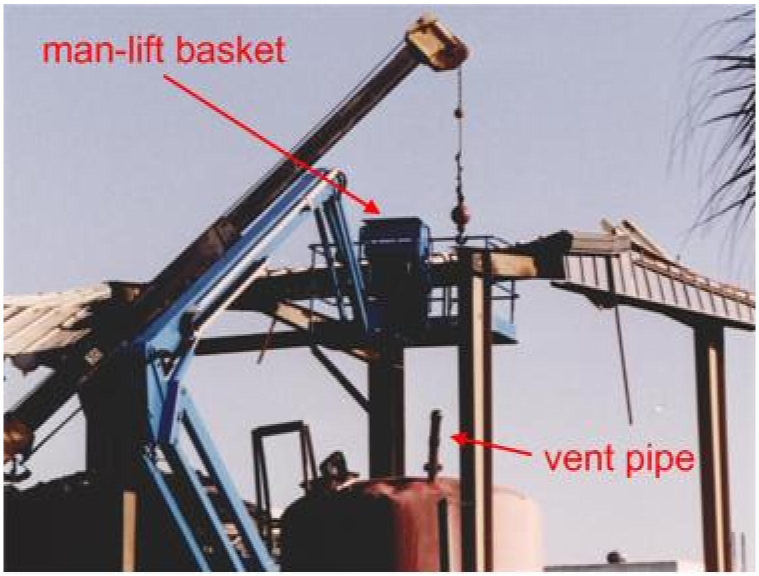

Figure 7. Location of man-lift basket and 4-inch vent pipe

Had the methanol piping and valves been constructed of steel, the system would most likely have remained intact. The mechanic in the crane would likely not have been killed, and the other two workers may have been less severely injured.

3.4 Methanol Tank Flame Arrester

The methanol storage tank vent was equipped with a flame arrester in accordance with NFPA 30. Flame arresters are devices that stop a flame while allowing gases and vapors to flow freely and work by channeling gas and/or vapor through narrow gaps between metal plates. The transfer of heat to the plates extinguishes a flame moving through the gaps. Proper sizing of the gaps and plates is critical to the flame arrester performance. Any blockage in the gaps or corrosion of the plates can render a flame arrester ineffective.

The flame arrester on the methanol storage tank vent pipe was a Protectoseal Model No. 864 (Figure 8). Because the vent through the flame arrester was always open, the tank discharged methanol vapors when filled or warmed and took in air when drained or cooled.

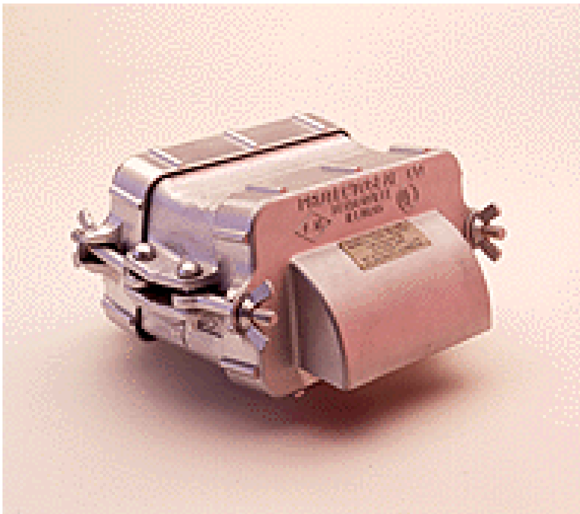

Figure 8. Protectoseal Model No. 864 flame arrester

(picture courtesy of Protectoseal)

The flame arrester plates and housing were aluminum. Published corrosion data[18] indicates that methanol corrodes aluminum. The flame arrester was severely corroded on the interior surface, the plates were clogged with aluminum oxide scale, and plates were broken with portions missing (Figure 9 and Figure 10). Corrosion on the broken plate edges indicates that the broken plate damage most likely occurred prior to the incident.

[18] NACE International, The Corrosion Society (2002). Corrosion Survey Database (COR·SUR). NACE International.

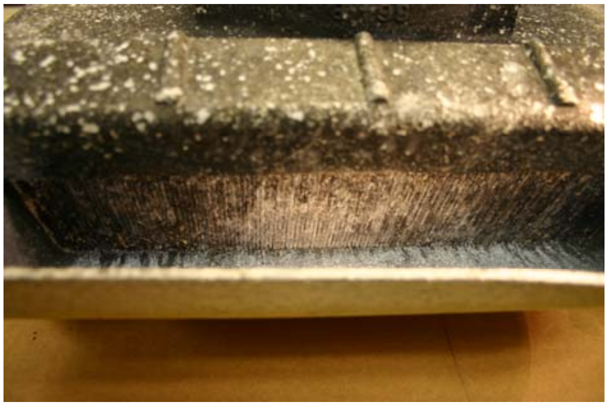

Figure 9. Flame arrester plate corrosion (outside)

Figure 10. Flame arrester plate corrosion (inside)

Correspondence among the construction company (IRIC); the construction manager (CDM); and the City of Daytona Beach indicated that the need for a flame arrester was identified late in the project. IRIC proposed three models for purchase, all of which had aluminum plates installed in an aluminum housing. CDM selected the Protectoseal Model 864 because it was readily available. Although Protectoseal offered flame arresters made of materials not corroded by methanol, none of these was proposed or selected.

Flame arresters require regular inspection and maintenance (cleaning) to maintain functionality. Dirt and small particles collecting in the narrow gaps between the flame arrester plates, insects nesting in the housing, and corrosion can degrade performance. Regular inspection can identify excessive corrosion. In 1993, when the methanol system became operational, both Protectoseal[19] and a major methanol producer[20] recommended regular flame arrester maintenance and inspection. However, no requirement for flame arrester maintenance and inspection was included with the operation and maintenance instructions CDM provided the City. Interviews indicate that Bethune Point WWTP personnel were unaware of the need to inspect and maintain the flame arrester.

The CSB concluded that the flame arrester did not prevent the fire outside the tank from igniting the tank contents. Routine inspections would have detected the corrosion in the flame arrester that occurred over 12 years. The use of an aluminum flame arrester in methanol service, coupled with the lack of inspection and maintenance, allowed the flame arrester to corrode to the point that it no longer functioned.

[19] From literature normally provided by Protectoseal with flame arresters.

[20] Based on a DuPont methanol product guide provided by CDM and found in the City of Daytona Beach contract file for the 1993 upgrades to the Bethune Point WWTP.

4.0 Regulatory Analysis

4.1 OSHA Regulations

The City of Daytona Beach was not required to comply with or implement OSHA regulations. Had the city implemented hot work and HAZCOM programs conforming to OSHA safety standards, the hazards of using a torch in proximity to the methanol tank would likely have been identified and possibly prevented.

Public employers are not covered by the Occupational Safety and Health Act of 1970 because section 3(5) of the act defines "employer" as "a person engaged in a business affecting commerce that has employees, but does not include the United States (not including the United States Postal Service) or any State or political subdivision of a State."

The Occupational Safety and Health Act includes two opportunities for city, county, and state employers to provide OSHA coverage: "state plans" and "public employee-only plans." Section 18 of the Act authorizes states to establish their own occupational safety and health programs, or "state plans," and Section 18(c)(6) requires all states that run their own state plans to establish "an effective and comprehensive occupational safety and health program applicable to all employees of public agencies of the State and its political subdivisions." Twenty one states have adopted OSHA state plans. OSHA regulation 29 CFR 1956.1 allows states that do not have state plans to adopt "public employee-only plans" to provide OSHA coverage even where no state plan covering private employers is in effect. Three states have adopted these "public employee plans" Appendix B includes a list of states and their OSHA coverage.

The federal government establishes staffing and enforcement benchmarks for "state plans" and "public employee-only plans" to ensure enforcement and standards are "at least as effective" as the federal program. The state programs must also adopt all OSHA standards or issue their own standards that are "at least as effective as" OSHA standards. The federal government matches funding for approved "state plans" and "public employee-only plans."[21]

OSHA coverage provides four major benefits to employees:

- Coverage by OSHA standards (or equivalent state standards). Most of these are in 29 CFR 1910 (General Industry) and 1926 (Construction).

- Ability to file a complaint and receive an OSHA inspection without fear of employer retaliation.

- Right to participate in, receive the results of OSHA inspections, and have an opening and closing conference with the OSHA inspector separate from the employer.

- Ability to request and receive information from the employer on workplace monitoring of chemicals, noise and radiation levels, and chemical hazards covered by the OSHA HAZCOM standard. The Occupational Safety and Health Act also gives employees the right to review their employer's injury and illness log and relevant exposure and medical records.

Some of the remaining 26 states without "state plans" and "public employee-only plans" provide safety and health protection to public employees, although these programs do not receive federal funding and are not subject to federal OSHA oversight. Florida had such a program until it was eliminated in 2000.

[21] Further information about state plans is available at http://www.osha.gov/dcsp/osp/index.html.

4.2 Florida Public Employee Safety

4.2.1 History

The Florida Occupational Safety and Health Act, [22] enacted in 1982, directed the Florida Division of Safety (a division within the Department of Labor and Employment Security) to assist employers (both private and public, including cities and counties) to make their workplaces safer and decrease the frequency and severity of on-the-job injuries. State, city, and county employers were required to comply with most OSHA regulations and the state had the authority to cite public employers.

The Florida legislature repealed Chapter 442 in 1999.[23] Until its repeal, the Florida legislature appropriated approximately $11 million per year for occupational safety and health programs, which funded a statewide staff of 146 employees, 21 of whom worked in a consulting program for private small businesses that received matching funds from the federal government. The remaining 125 staff members addressed public sector (i.e., state and municipal employers) occupational safety and health compliance.

Following the repeal of Chapter 442, the governor issued an executive order[24] addressing public employee safety and health. State agencies listed in the executive order were directed “to voluntarily comply” with General Industry OSHA standards.[25] The executive order recommends that each city and county (as well as state agencies not specifically covered in the first part of the executive order) “review… existing policies, practices and procedures concerning workplace safety and implement any policies, practices or

[22] Florida Statutes, Chapter 442.20.
[23] Chapter 2001-65, House Bill No. 669. The repeal was effective July 1, 2000.
[24] Florida Executive Order Number 2000-292 dated September 25, 2000.
[25] 29 CFR 1910, Subparts C through T and Subpart Z. Construction standards in 29 CFR 1926 are excluded.

procedures made necessary by the repeal of Chapter 442." [26] The Florida legislature provided no funding to state agencies, cities or counties to implement the executive order.

Today, no Florida state laws or regulations exist to require municipalities to implement safe work practices for or communicate chemical hazards to municipal employees.

4.2.2 Florida Municipal Safety Program Survey

The CSB conducted a telephone survey of six Florida cities and three Florida counties to determine the extent of their voluntary compliance with OSHA standards. As part of the survey, the CSB investigators interviewed occupational safety and health or loss control managers.

Most entities surveyed reported having policies requiring compliance with OSHA standards. In some cases, the CSB also spoke with union representatives at the surveyed city or county. Some union representatives confirmed voluntary compliance with OSHA standards, but others described hazardous conditions and incidents indicating that OSHA standards and good safety practices are not fully implemented and that conditions are not evaluated or remedied, despite employee complaints.

Voluntary compliance with OSHA standards does not provide public sector employees with all the rights conveyed to private sector employees (and covered public sector employees) under the Occupational Safety and Health Act. Even if the employer conforms with all OSHA General Industry standards, employees remain without the legal right to receive an OSHA inspection or to review relevant records and medical and exposure information. Additionally, non-mandatory safety programs are vulnerable to changes in budgetary priorities.

[26] Although mandatory for state agencies, other political subdivisions and the public have no legal obligation to comply with an executive order issued by the governor.

4.2.3 Florida Public Facility Chemical Incidents

In addition to surveying several Florida cities and counties, the CSB researched[27] the frequency and severity of chemical incidents at Florida public facilities. In addition to the incident at the Bethune WWTP, the CSB found 33 additional chemical incidents at public facilities in the last five years. The incidents resulted in 9 injuries, 23 medical evaluations for chemical exposure, and 15 evacuations involving the facility or surrounding community. All of these incidents involved chemicals that would normally be included in an OSHA compliant hazard communication program.

4.2.4 Safety Consultation

The University of South Florida administers a voluntary private sector worker safety consultation program for the State of Florida. Half of the program funding comes from the Florida's Workers' Compensation Trust Fund, the other half as matching funds from the U.S. Department of Labor.[28] The program has a state-wide staff of 17 and offers confidential health and safety compliance consulting to private small business owners, with the goal of encouraging them to voluntarily improve workplace safety. Because of restrictions on federal funding, the program is prohibited from offering consultation to Florida's public employers.

[27] Media reports, National Response Center reports and the EPA Risk Management Program database.

[28] Section 21(d) of the Occupational Safety and Health Act of 1970 authorizes states to enter into a cooperative agreement with OSHA and receive matching Federal funds for consultation programs.

5.0 Key Findings

1. The City of Daytona Beach has no program, written or otherwise, to control hot work at city facilities.

2. The CSB found no evidence that workers at the Bethune Point WWTP received any methanol hazard training in the last 10 years.

3. The City of Daytona Beach does not require work plan reviews to evaluate the safety of non-routine tasks.

4. OSHA 1910.106 permits the use of plastic piping in flammable liquid piping systems when necessary but does not define necessary.

5. NFPA 30 permits the use of plastic piping in flammable liquid piping systems under certain conditions.

6. The methanol tank did not comply with NFPA 30. Valves and their connection to the tank were PVC instead of steel.

7. The failure of the PVC piping attached to the tank and in the methanol system greatly increased the consequences of the incident.

8. Flame arrester maintenance requirements were not included in the operation and maintenance manual for the methanol system.

9. An aluminum flame arrester was installed on the methanol tank; methanol corrodes aluminum.

10. The flame arrester was not inspected or cleaned since its installation in 1993.

11. The flame arrester was so degraded (gaps between the plates inside the flame arrester were plugged with dirt and aluminum oxide and portions of the plates were corroded away) that it did not prevent a flame from entering the tank which greatly increased the consequences of the incident.

12. No Florida state laws or regulations exist to require municipalities to implement safe work practices.

13. No Florida state laws or regulations exist to require municipalities to communicate chemical hazards to municipal employees.

14. Florida municipalities are not covered by OSHA workplace safety standards.

15. No state or federal oversight of public employee safety exists in the State of Florida.

6.0 Root and Contributing Causes

6.1 Root Causes

The City of Daytona Beach

1. did not implement adequate controls for hot work at the Bethune Point WWTP; and

2. had an ineffective HAZCOM program.

6.2 Contributing Causes

1. The City of Daytona Beach has no systematic program to evaluate the safety of non-routine tasks.

2. The aboveground piping and valves in the methanol system were constructed of PVC in lieu of steel.

3. An aluminum flame arrester was installed on the methanol tank even though methanol is known to corrode aluminum.

4. The operation and maintenance manual for the Bethune Point WWTP did not include a requirement to maintain the flame arrester.

7.0 Recommendations

The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the facility where the incident occurred, the parent company, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations and labor unions.

Governor and Legislature of the State of Florida

2006-03-I-FL-R1

Enact legislation requiring state agencies and each political subdivision (i.e. counties and municipalities) of Florida to implement policies, practices, procedures, including chemical hazards covering the workplace health and safety of Florida public employees that are at least as effective as OSHA. Establish and fund a mechanism to ensure compliance with these standards.

Consider legislation providing coverage of Florida public employees under an occupational safety and health program in accordance with Section 18(b) of the Occupational Safety and Health Act of 1970, and Code of Federal Regulations 29 CFR 1956.1.

2006-03-I-FL-R2

Develop and fund a workplace safety and health consultation program for Florida public employees similar to the private sector program currently administered by the Florida Safety Consultation Program at the University of South Florida.

City of Daytona Beach

2006-03-I-FL-R3

Adopt city ordinances to require departments to implement policies, practices, and procedures concerning safety and health in the workplace for city employees that are at least as effective as relevant OSHA standards. Emphasize compliance with chemical standards, including hot work procedures (OSHA Welding, Cutting, and Brazing Standard, Sections 1910.251 and 1910.252) and chemical hazard communication (OSHA Hazard Communication Standard 29 CFR 1910.1200). Implement procedures to ensure compliance with these policies, practices and procedures.

2006-03-I-FL-R4

Ensure that flammable liquid storage tanks used throughout the city comply with NFPA 30 and minimum federal standards in 29 CFR 1910.106, including appropriate piping and flame arresters.

National Fire Protection Association

2006-03-I-FL-R5

Revise NFPA 30 to specifically exclude the use of thermoplastics in aboveground flammable liquid service.

U.S. Department of Labor, Occupational Safety and Health Administration

2006-03-I-FL-R6

Revise 29 CFR 1910.106 to specifically exclude the use of thermoplastics in aboveground flammable liquid service.

Water Environment Federation

2006-03-I-FL-R7

Work with the Methanol Institute to prepare and distribute a technical bulletin containing information on the safe receipt, storage, use, and dispensing of methanol in wastewater treatment plants. In addition, include information on basic fire and explosion prevention measures when using bulk methanol (e.g., flame arrester maintenance, hot work programs, electrical classification).

2006-03-I-FL-R8

Work with the Methanol Institute to prepare safety training materials for wastewater treatment facilities that use methanol.

Methanol Institute

2006-03-I-FL-R9

Work with the Water Environment Federation to prepare and distribute a technical bulletin containing information on the safe receipt, storage, use, and dispensing of methanol in wastewater treatment plants. In addition, include information on basic fire and explosion prevention measures when using bulk methanol (e.g., flame arrester maintenance, hot work programs, electrical classification).

2006-03-I-FL-R10

Work with the Water Environment Federation to prepare safety training materials for wastewater treatment facilities that use methanol.

Camp Dresser & McKee Inc.

2006-03-I-FL-R11

Revise CDM policies and procedures to ensure that appropriate quality control measures are applied so that designs specify appropriate materials and comply with applicable safety standards. Ensure that wastewater treatment plant design engineers are aware of the importance of proper material selection as well as the findings and recommendations of this report.

2006-03-I-FL-R12

Communicate the findings and recommendations of this report to all companies that contracted with CDM for methanol and other flammable liquid systems that were constructed with aboveground plastic pipe. Recommend replacing plastic pipe with an appropriate material in accordance with NFPA 30 and OSHA 1910.106.

2006-03-I-FL-R13

Communicate the findings and recommendations of this report to all companies that contracted with CDM for flammable liquid systems that included a flame arrester. Emphasize the importance of periodic maintenance of the flame arrester to ensure its effective performance.

By the

U.S. Chemical Safety and Hazard Investigation Board

Carolyn W. Merritt
Chair

John S. Bresland
Member

Gary Visscher
Member

William Wark
Member

William Wright
Member

Date of Board Approval

8.0 References

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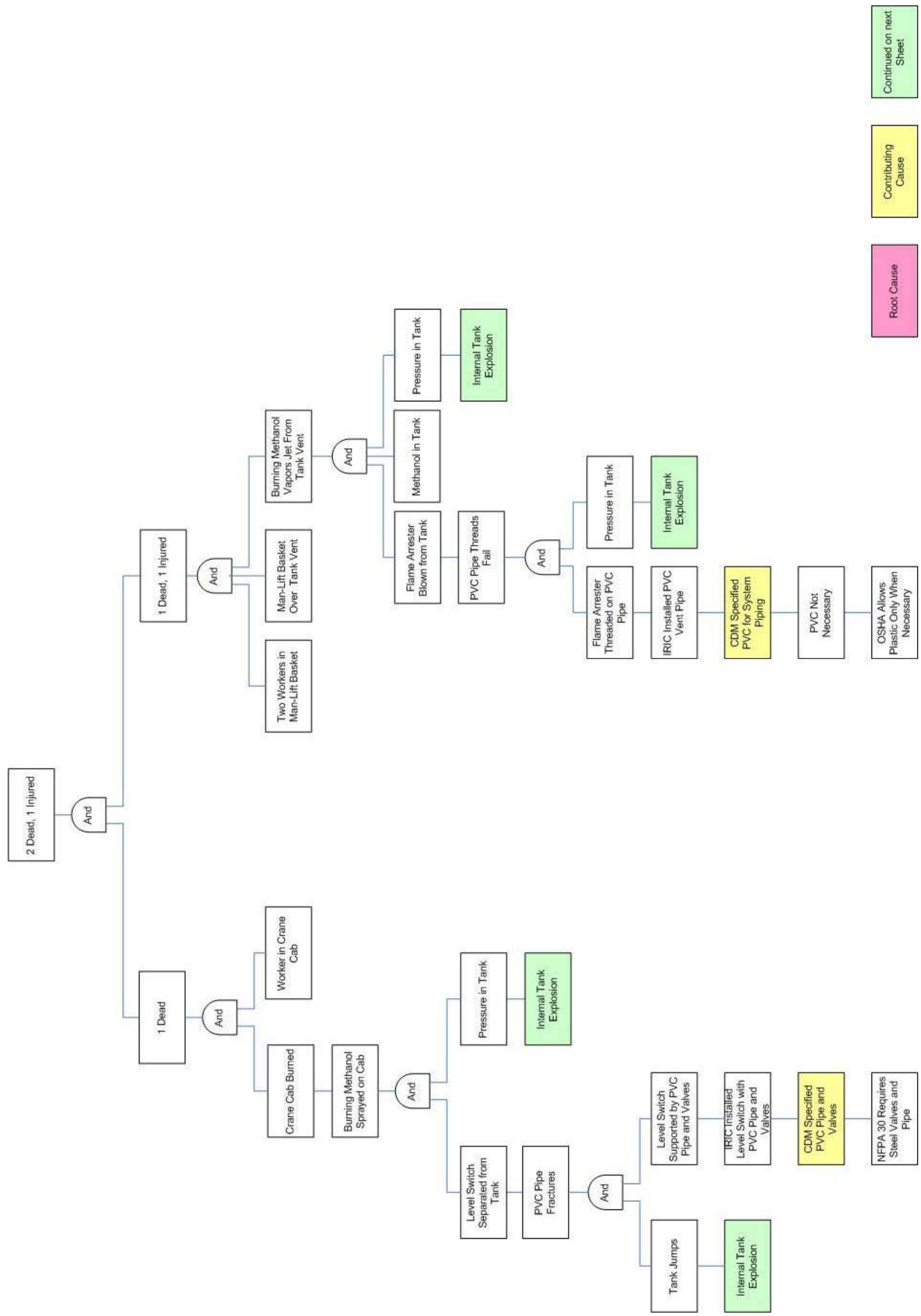
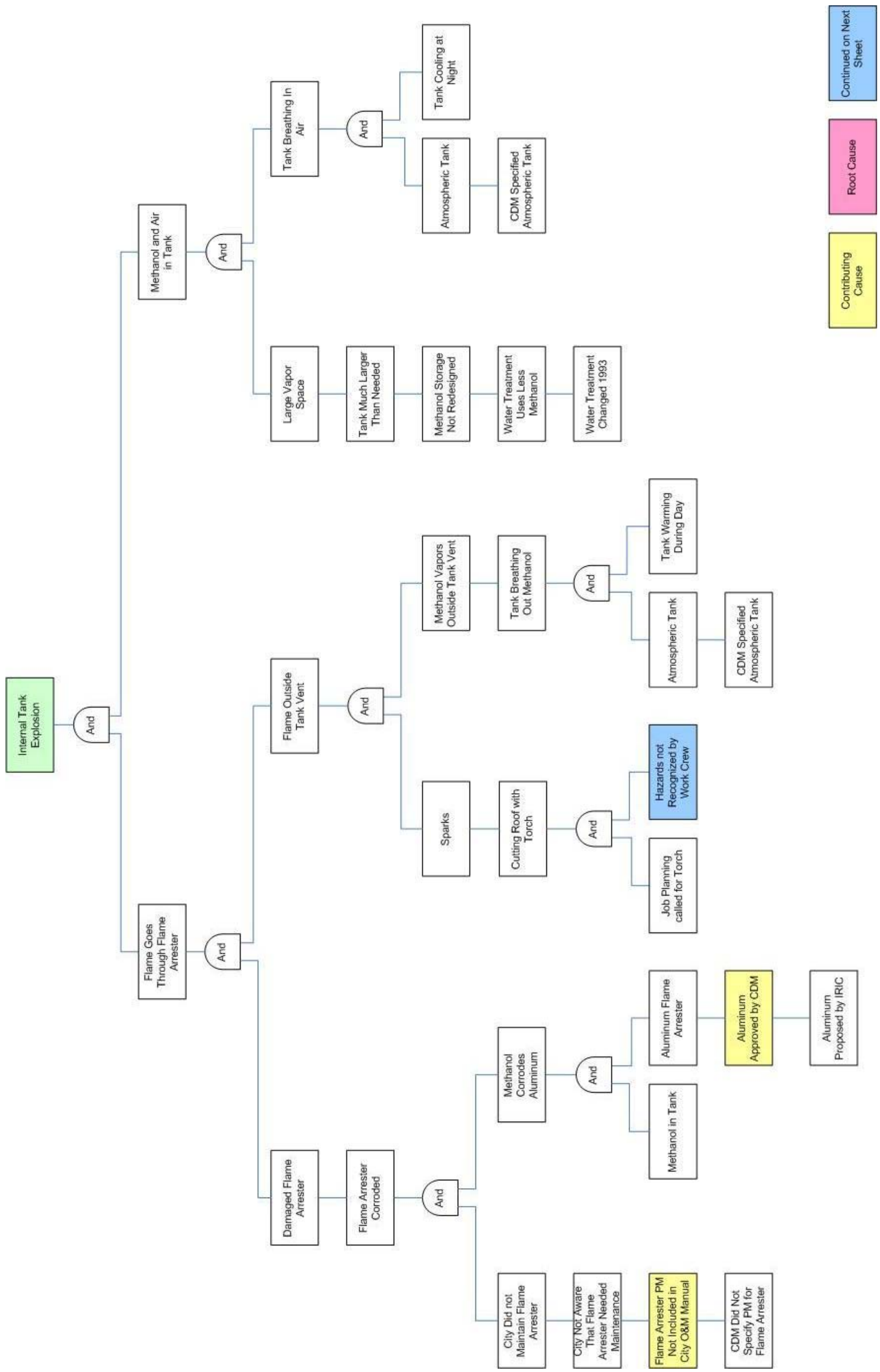
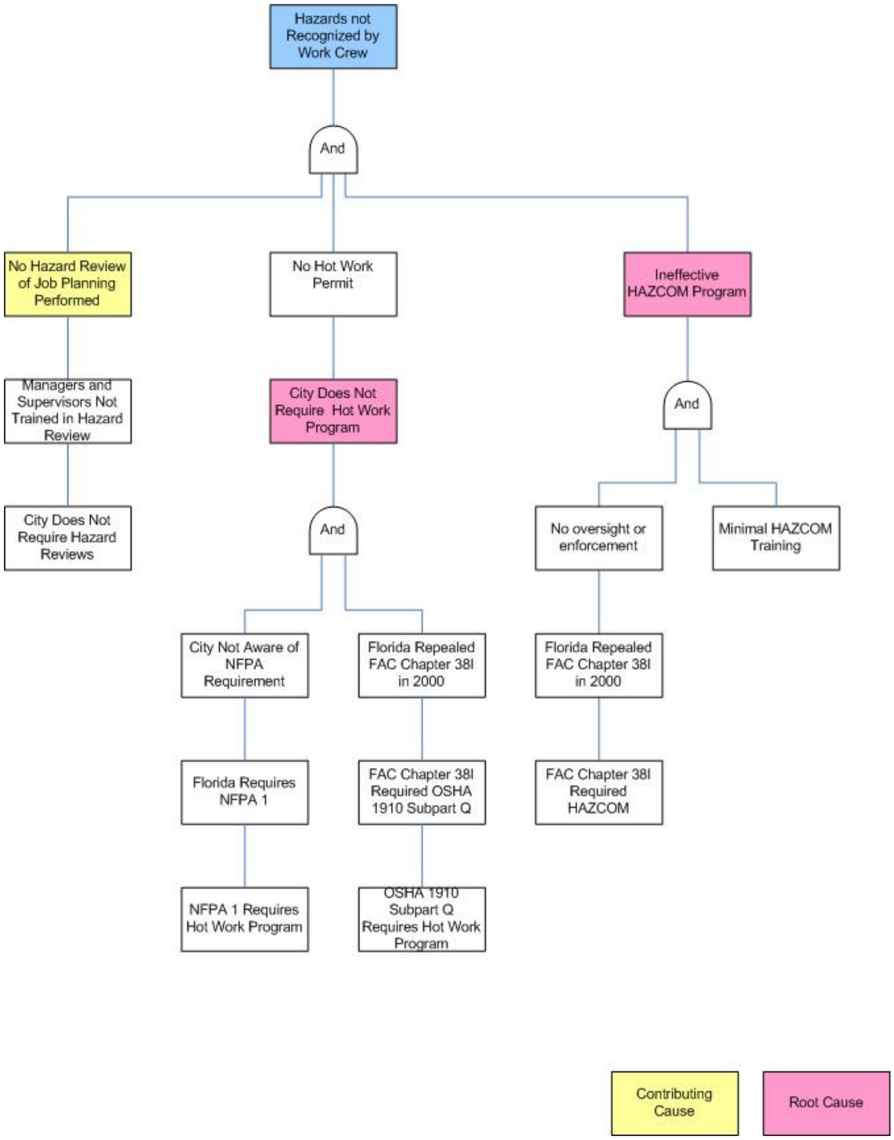
Appendix A: ROOT CAUSE LOGIC DIAGRAM


2 Dead, 1 Injured
And
1 Dead
And
Worker in Crane Cab
Crane Cab Burned
Burning Methanol Sprayed on Cab
And
Pressure in Tank
Internal Tank Explosion
Level Switch Separated from Tank
PVC Pipe Fractures
And
Tank Jumps
Internal Tank Explosion
Level Switch Supported by PVC Pipe and Valves
IRIC Installed Level Switch with PVC Pipe and Valves
CDM Specified PVC Pipe and Valves
NFPA 30 Requires Steel Valves and Pipe
1 Dead, 1 Injured
And
Two Workers in Man-Lift Basket
Man-Lift Basket Over Tank Vent
Burning Methanol Vapors Jet From Tank Vent
And
Flame Arrester Blown from Tank
Methanol in Tank
Pressure in Tank
Internal Tank Explosion
PVC Pipe Threads Fail
And
Flame Arrester Threaded on PVC Pipe
Pressure in Tank
Internal Tank Explosion
IRIC Installed PVC Vent Pipe
CDM Specified PVC for System Piping
PVC Not Necessary
OSHA Allows Plastic Only When Necessary
Root Cause
Contributing Cause
Continued on next Sheet


Internal Tank Explosion
And
Methanol and Air in Tank
And
Tank Breathing In Air
And
Tank Cooling at Night
Atmospheric Tank
CDM Specified Atmospheric Tank
Large Vapor Space
Tank Much Larger Than Needed
Methanol Storage Not Redesigned
Water Treatment Uses Less Methanol
Water Treatment Changed 1993
Flame Goes Through Flame Arrester
And
Flame Outside Tank Vent
And
Methanol Vapors Outside Tank Vent
Tank Breathing Out Methanol
And
Tank Warming During Day
Atmospheric Tank
CDM Specified Atmospheric Tank
Sparks
Cutting Roof with Torch
And
Hazards not Recognized by Work Crew
Job Planning called for Torch
Damaged Flame Arrester
Flame Arrester Corroded
And
Methanol Corrodes Aluminum
And
Aluminum Flame Arrester
Aluminum Approved by CDM
Aluminum Proposed by IRIC
Methanol in Tank
City Did not Maintain Flame Arrester
City Not Aware That Flame Arrester Needed Maintenance
Flame Arrester PM Not Included in City O&M Manual
CDM Did Not Specify PM for Flame Arrester
Continued on Next Sheet
Root Cause
Contributing Cause


Hazards not Recognized by Work Crew
And
No Hazard Review of Job Planning Performed
No Hot Work Permit
Ineffective HAZCOM Program
Managers and Supervisors Not Trained in Hazard Review
City Does Not Require Hot Work Program
And
City Does Not Require Hazard Reviews
And
No oversight or enforcement
Minimal HAZCOM Training
City Not Aware of NFPA Requirement
Florida Repealed FAC Chapter 38I in 2000
Florida Repealed FAC Chapter 38I in 2000
Florida Requires NFPA 1
FAC Chapter 38I Required OSHA 1910 Subpart Q
FAC Chapter 38I Required HAZCOM
NFPA 1 Requires Hot Work Program
OSHA 1910 Subpart Q Requires Hot Work Program
Contributing Cause
Root Cause

Appendix B: PUBLIC EMPLOYEE OSHA COVERAGE

PUBLIC EMPLOYEE OSHA COVERAGE

State	OSHA Coverage
Alabama	
Alaska	State Plan
Arizona	State Plan
Arkansas	
California	State Plan
Colorado	
Connecticut	Public Employee Only Plan
Delaware	
Florida	
Georgia	
Hawaii	State Plan
Illinois	
Indiana	State Plan
Iowa	State Plan
Kansas	
Kentucky	State Plan
Louisiana	
Maine	
Maryland	State Plan
Massachusetts	
Michigan	State Plan
Minnesota	State Plan
Mississippi	
Missouri	
Montana	
Nebraska	
Nevada	State Plan
New Hampshire	
New Jersey	Public Employee Only Plan
New Mexico	State Plan

State	OSHA Coverage
New York	Public Employee Only Plan
North Carolina	State Plan
North Dakota	
Ohio	
Oklahoma	
Oregon	State Plan
Pennsylvania	
Puerto Rico	State Plan
Rhode Island	
South Carolina	State Plan
Tennessee	State Plan
Texas	
Utah	State Plan
Vermont	State Plan
Virgin Islands	Public Employee Only Plan
Virginia	State Plan
Washington	State Plan
West Virginia	
Wisconsin	
Wyoming	State Plan

United States Government Accountability Office

GAO

Report to Congressional Requesters

September 2012

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

GAO

Accountability * Integrity * Reliability

GAO-12-732

September 2012

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

GAO Accountability * Integrity * Reliability

Highlights

Highlights of GAO-12-732, a report to congressional requesters

Why GAO Did This Study

New applications of horizontal drilling techniques and hydraulic fracturing—in which water, sand, and chemical additives are injected under high pressure to create and maintain fractures in underground formations—allow oil and natural gas from shale formations (known as "shale oil" and "shale gas") to be developed. As exploration and development of shale oil and gas have increased—including in areas of the country without a history of oil and natural gas development—questions have been raised about the estimates of the size of these resources, as well as the processes used to extract them.

GAO was asked to determine what is known about the (1) size of shale oil and gas resources and the amount produced from 2007 through 2011 and (2) environmental and public health risks associated with the development of shale oil and gas. GAO reviewed estimates and data from federal and nongovernmental organizations on the size and production of shale oil and gas resources. GAO also interviewed federal and state regulatory officials, representatives from industry and environmental organizations, oil and gas operators, and researchers from academic institutions.

GAO is not making any recommendations in this report. We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review. The Department of the Interior and the Environmental Protection Agency provided technical comments, which we incorporated as appropriate. The Department of Energy did not provide comments.

View GAO-12-732. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

Estimates of the size of shale oil and gas resources in the United States by the Energy Information Administration (EIA), U.S. Geological Survey (USGS), and the Potential Gas Committee—three organizations that estimate the size of these resources—have increased over the last 5 years, which could mean an increase in the nation's energy portfolio. For example, in 2012, EIA estimated that the amount of technically recoverable shale gas in the United States was 482 trillion cubic feet—an increase of 280 percent from EIA's 2008 estimate. However, according to EIA and USGS officials, estimates of the size of shale oil and gas resources in the United States are highly dependent on the data, methodologies, model structures, and assumptions used to develop them. In addition, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. Estimates are based on data available at a given point in time and will change as additional information becomes available. In addition, domestic shale oil and gas production has experienced substantial growth; shale oil production increased more than fivefold from 2007 to 2011, and shale gas production increased more than fourfold from 2007 to 2011.

Oil and gas development, whether conventional or shale oil and gas, pose inherent environmental and public health risks, but the extent of these risks associated with shale oil and gas development is unknown, in part, because the studies GAO reviewed do not generally take into account the potential long-term, cumulative effects. For example, according to a number of studies and publications GAO reviewed, shale oil and gas development poses risks to air quality, generally as the result of (1) engine exhaust from increased truck traffic, (2) emissions from diesel-powered pumps used to power equipment, (3) gas that is flared (burned) or vented (released directly into the atmosphere) for operational reasons, and (4) unintentional emissions of pollutants from faulty equipment or impoundments—temporary storage areas. Similarly, a number of studies and publications GAO reviewed indicate that shale oil and gas development poses risks to water quality from contamination of surface water and groundwater as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gases and chemicals. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In addition, shale oil and gas development poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting fluids underground. However, the extent of these risks is unknown. For example, the studies and publications GAO reviewed on air quality conditions provide information for a specific site at a specific time but do not provide the information needed to determine the overall cumulative effects that shale oil and gas activities may have on air quality. Further, the extent and severity of environmental and public health risks identified in the studies and publications GAO reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations; climatic conditions; business practices; and regulatory and enforcement activities.

Contents

Abbreviations

BLM	Bureau of Land Management
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
NORM	naturally occurring radioactive materials
Tcf	technically recoverable gas
USGS	U.S. Geological Survey

GAO
Accountability * Integrity * Reliability

United States Government Accountability Office
Washington, DC 20548

September 5, 2012

Congressional Requesters

For decades, the United States has relied on imports of oil and natural gas to meet domestic needs. As recently as 2007, the expectation was that the nation would increasingly rely on imports of natural gas to meet its growing demand. However, recent improvements in technology have allowed companies that develop petroleum resources to extract oil and natural gas from shale formations,[1] known as "shale oil" and "shale gas," respectively, which were previously inaccessible because traditional techniques did not yield sufficient amounts for economically viable production. In particular, as we reported in January 2012, new applications of horizontal drilling techniques and hydraulic fracturing—a process that injects a combination of water, sand, and chemical additives under high pressure to create and maintain fractures in underground rock formations that allow oil and natural gas to flow—have prompted a boom in shale oil and gas production.[2] According to the Department of Energy (DOE), America's shale gas resource base is abundant, and development of this resource could have beneficial effects for the nation, such as job creation.[3] According to a report by the Baker Institute, domestic shale gas development could limit the need for expensive imports of these resources—helping to reduce the U.S. trade deficit.[4] In addition, replacing older coal burning power generation with new natural gas-fired generators could reduce greenhouse gas emissions and result in fewer air pollutants

[1]Shale oil differs from "oil shale." Shale is a sedimentary rock that is predominantly composed of consolidated clay-sized particles. Oil shale requires a different process to extract. Specifically, to extract the oil from oil shale, the rock needs to be heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. Oil shale is not currently economically viable to produce. For additional information on oil shale, see GAO, *Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development*, GAO-11-35 (Washington, D.C.: Oct. 29, 2010).

[2]GAO, *Energy-Water Nexus: Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production*, GAO-12-156 (Washington, D.C.: Jan. 9, 2012).

[3]EIA is a statistical agency within DOE that provides independent data, forecasts, and analyses.

[4]The Baker Institute is a public policy think tank located on the Rice University campus.

for the same amount of electric power generated.[5] Early drilling activity in shale formations was centered primarily on natural gas, but with the falling price of natural gas companies switched their focus to oil and natural gas liquids, which are a more valuable product.[6]

As exploration and development of shale oil and gas have increased in recent years—including in areas of the country without a history of oil and natural gas activities—questions have been raised about the estimates of the size of domestic shale oil and gas resources, as well as the processes used to extract them.[7] For example, some organizations have questioned the accuracy of the estimates of the shale gas supply. In particular, some news organizations have reported concerns that such estimates may be inflated. In addition, concerns about environmental and public health effects of the increased use of horizontal drilling and hydraulic fracturing, particularly on air quality and water resources, have garnered extensive public attention. According to the International Energy Agency, some questions also exist about whether switching from coal to natural gas will lead to a reduction in greenhouse gas emissions—based, in part, on uncertainty about additional emissions from the development of shale gas. These concerns and other considerations have led some communities and certain states to impose restrictions or moratoriums on drilling operations to allow time to study and better understand the potential risks associated with these practices.

In this context, you asked us to provide information on shale oil and gas. This report describes what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.[8]

[5]EIA reported that using natural gas over coal would lower emissions in the United States, but some researchers have reported that greater reliance on natural gas would fail to significantly slow climate change.

[6]The natural gas liquids include propane, butane, and ethane, and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants.

[7]For the purposes of this report, resources represent all oil or natural gas contained within a formation and can be divided into resources and reserves.

[8]For the purposes of this report, we refer to risk as a threat or vulnerability that has potential to cause harm.

To determine what is known about the size of shale oil and gas resources and the amount of shale oil and gas produced, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the EIA, the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academics and industry representatives. We interviewed key officials from these agencies and the committee about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators—companies that develop petroleum resources to extract oil and natural gas.[9] To determine what is known about the amount of shale oil and gas produced from 2007 through 2011, we obtained data from EIA—which is responsible for estimating and reporting this and other energy information. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection efforts. We also met with officials from states, representatives from private industry, and researchers from academic institutions who are familiar with these data and EIA's methodology. We discussed the sources and reliability of the data with these officials and found the data sufficiently reliable for the purposes of this report. For all estimates we report, we reviewed the methodologies used to derive them and also found them sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas,[10] we reviewed studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. We identified these studies by conducting

[9]Proved reserves refer to the amount of oil and gas that have been discovered and defined.

[10]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale, but for the purposes of this report we focused on development of shale formations. Specifically, coalbed methane and tight sandstone formations may rely on these practices and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on shale formations.

a literature search, and by asking for recommendations during interviews with federal, state, and tribal officials; representatives from industry, trade organizations, environmental, and other nongovernmental groups; and researchers from academic institutions. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified currently known potential risks for shale oil and gas development. However, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas wells may be constructed. Second, the extent to which operators use effective best management practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few studies that are based on comparing predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse conditions to shale oil and gas development. In addition, changes to the federal, state, and local regulatory environments and the effectiveness of implementing and enforcing regulations will affect operators' future activities and, therefore, the level of risk associated with future development of oil and gas resources. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices which, in turn, may vary across oil and gas companies, making it difficult to distinguish between risks associated with the process to develop shale oil and gas from risks that are specific to particular business practices. To obtain additional perspectives on issues related to environmental and public health risks, we interviewed federal officials from DOE's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management (BLM) and Bureau of Indian Affairs, and the Environmental Protection Agency (EPA); state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas;[11] tribal officials from the Osage Nation; shale oil and gas operators;

[11]We selected these states because they are involved with shale oil and gas development.

representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. Appendix I provides additional information on our scope and methodology.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

This section includes (1) an overview of oil and natural gas, (2) the shale oil and gas development process, (3) the regulatory framework, (4) the location of shale oil and gas in the United States, and (5) information on estimating the size of these resources.

Overview

Oil and natural gas are found in a variety of geologic formations. Conventional oil and natural gas are found in deep, porous rock or reservoirs and can flow under natural pressure to the surface after drilling. In contrast to the free-flowing resources found in conventional formations, the low permeability of some formations, including shale, means that oil and gas trapped in the formation cannot move easily within the rock. On one extreme—oil shale, for example—the hydrocarbon trapped in the shale will not reach a liquid form without first being heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. In contrast, to extract shale oil and gas from the rock, fluids and proppants (usually sand or ceramic beads used to hold fractures open in the formation) are injected under high pressure to create and maintain fractures to increase permeability, thus allowing oil or gas to be extracted. Other formations, such as coalbed methane formations and tight sandstone formations,[12] may also require stimulation to allow oil or gas to be extracted.[13]

Most of the energy used in the United States comes from fossil fuels such as oil and natural gas. Oil supplies more than 35 percent of all the energy the country consumes, and almost the entire U.S. transportation fleet—cars, trucks, trains, and airplanes—depends on fuels made from oil. Natural gas is an important energy source to heat buildings, power the industrial sector, and generate electricity. Natural gas provides more than 20 percent of the energy used in the United States,[14] supplying nearly half of all the energy used for cooking, heating, and powering other home appliances, and generating almost one-quarter of U.S. electricity supplies.

The Shale Oil and Gas Development Process

The process to develop shale oil and gas is similar to the process for conventional onshore oil and gas, but shale formations may rely on the use of horizontal drilling and hydraulic fracturing—which may or may not be used on conventional wells. Horizontal drilling and hydraulic fracturing are not new technologies, as seen in figure 1, but advancements, refinements, and new uses of these technologies have greatly expanded oil and gas operators' abilities to use these processes to economically develop shale oil and gas resources. For example, the use of multistage hydraulic fracturing within a horizontal well has only been widely used in the last decade.[15]

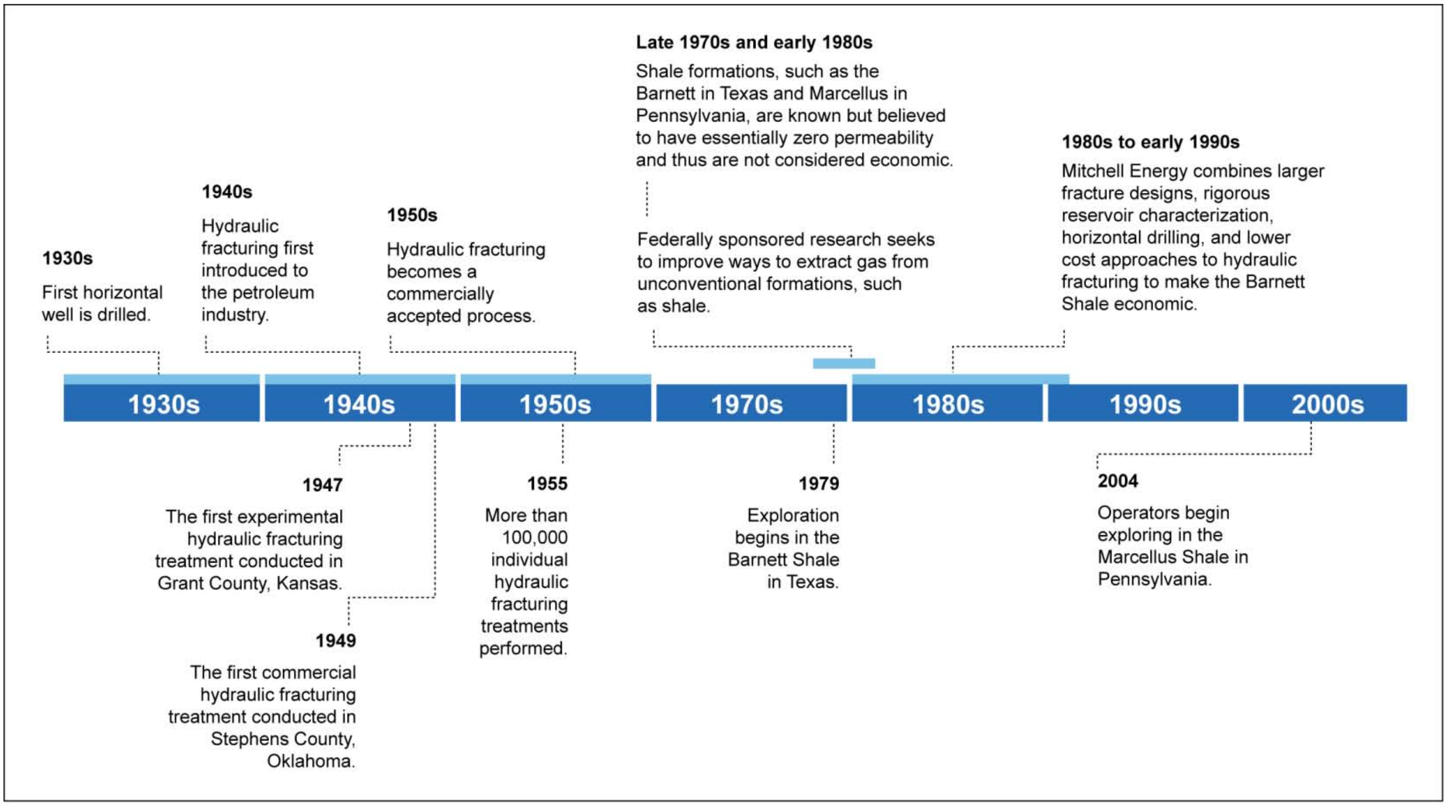
[12]Conventional sandstone has well-connected pores, but tight sandstone has irregularly distributed and poorly connected pores. Due to this low connectivity or permeability, gas trapped within tight sandstone is not easily produced.

[13]For coalbed methane formations, the reduction in pressure needed to extract gas is achieved through dewatering. As water is pumped out of the coal seams, reservoir pressure decreases, allowing the natural gas to release (desorb) from the surface of the coal and flow through natural fracture networks into the well.

[14]Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, a special report prepared at the request of the Department of Energy (Washington, D.C.: April 2009).

[15]Hydraulic fracturing is often conducted in stages. Each stage focuses on a limited linear section and may be repeated numerous times.

Figure 1: History of Horizontal Drilling and Hydraulic Fracturing



Source: GAO.

First, operators locate suitable shale oil and gas targets using seismic methods of exploration,[16] negotiate contracts or leases that allow mineral development, identify a specific location for drilling, and obtain necessary permits; then, they undertake a number of activities to develop shale oil and gas. The specific activities and steps taken to extract shale oil and gas vary based on the characteristics of the formation, but the development phase generally involves the following stages: (1) well pad

[16]The seismic method of exploration introduces energy into the subsurface through explosions in shallow “shot holes” by striking the ground forcefully (with a truck-mounted thumper), or by vibration methods. A portion of the energy returns to the surface after being reflected from the subsurface strata. This energy is detected by surface instruments, called geophones, and the information carried by the energy is processed by computers to interpret subsurface conditions.

preparation and construction, (2) drilling and well construction, and (3) hydraulic fracturing.[17]

Well Pad Preparation and Construction

The first stage in the development process is to prepare and construct the well pad site. Typically, operators must clear and level surface vegetation to make room for numerous vehicles and heavy equipment—such as the drilling rig—and to build infrastructure—such as roads—needed to access the site.[18] Then operators must transport the equipment that mixes the additives, water, and sand needed for hydraulic fracturing to the site—tanks, water pumps, and blender pumps, as well as water and sand storage tanks, monitoring equipment, and additive storage containers . Based on the geological characteristics of the formation and climatic conditions, operators may (1) excavate a pit or impoundment to store freshwater, drilling fluids, or drill cuttings—rock cuttings generated during drilling; (2) use tanks to store materials; or (3) build temporary transfer pipes to transport materials to and from an off-site location.

Drilling and Well Construction

The next stage in the development process is drilling and well construction. Operators drill a hole (referred to as the wellbore) into the earth through a combination of vertical and horizontal drilling techniques. At several points in the drilling process, the drill string and bit are removed from the wellbore so that casing and cement may be inserted. Casing is a metal pipe that is inserted inside the wellbore to prevent high-pressure fluids outside the formation from entering the well and to prevent drilling mud inside the well from fracturing fragile sections of the wellbore. As drilling progresses with depth, casings that are of a smaller diameter than the hole created by the drill bit are inserted into the wellbore and bonded in place with cement, sealing the wellbore from the surrounding formation.

Drilling mud (a lubricant also known as drilling fluid) is pumped through the wellbore at different densities to balance the pressure inside the wellbore and bring rock particles and other matter cut from the formation back to the rig. A blowout preventer is installed over the well as a safety measure to prevent any uncontrolled release of oil or gas and help

[17]The specific order of activities and steps may vary.

[18]According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, the average size of a well pad is 3.5 acres.

maintain control over pressures in the well. Drill cuttings, which are made up of ground rock coated with a layer of drilling mud or fluid, are brought to the surface. Mud pits provide a reservoir for mixing and holding the drilling mud. At the completion of drilling, the drilling mud may be recycled for use at another drilling operation.

Instruments guide drilling operators to the "kickoff point"—the point that drilling starts to turn at a slight angle and continues turning until it nears the shale formation and extends horizontally. Production casing and cement are then inserted to extend the length of the borehole to maintain wellbore integrity and prevent any communication between the formation fluids and the wellbore. After the casing is set and cemented, the drilling operator may run a cement evaluation log by lowering an electric probe into the well to measure the quality and placement of the cement. The purpose of the cement evaluation log is to confirm that the cement has the proper strength to function as designed—preventing well fluids from migrating outside the casing and infiltrating overlying formations. After vertical drilling is complete, horizontal drilling is conducted by slowly angling the drill bit until it is drilling horizontally. Horizontal stretches of the well typically range from 2,000 to 6,000 feet long but can be as long as 12,000 feet long, in some cases.

Throughout the drilling process, operators may vent or flare some natural gas, often intermittently, in response to maintenance needs or equipment failures. This natural gas is either released directly into the atmosphere (vented) or burned (flared). In October 2010, we reported on venting and flaring of natural gas on public lands.[19] We reported that vented and flared gas on public lands represents potential lost royalties for the federal government and contributes to greenhouse gas emissions. Specifically, venting releases methane and volatile organic compounds, and flaring emits carbon dioxide, both greenhouse gases that contribute to global climate change. Methane is a particular concern since it is a more potent greenhouse gas than carbon dioxide.

Hydraulic Fracturing

The next stage in the development process is stimulation of the shale formation using hydraulic fracturing. Before operators or service companies perform a hydraulic fracture treatment of a well, a series of

[19]GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 (Washington, D.C.: Oct. 29, 2010).

tests may be conducted to ensure that the well, wellhead equipment, and fracturing equipment can safely withstand the high pressures associated with the fracturing process. Minimum requirements for equipment pressure testing can be determined by state regulatory agencies for operations on state or private lands. In addition, fracturing is conducted below the surface of the earth, sometimes several thousand feet below, and can only be indirectly observed. Therefore, operators may collect subsurface data—such as information on rock stresses[20] and natural fault structures—needed to develop models that predict fracture height, length, and orientation prior to drilling a well. The purpose of modeling is to design a fracturing treatment that optimizes the location and size of induced fractures and maximizes oil or gas production.

To prepare a well to be hydraulically fractured, a perforating tool may be inserted into the casing and used to create holes in the casing and cement. Through these holes, fracturing fluid—that is injected under high pressures—can flow into the shale (fig. 2 shows a used perforating tool).

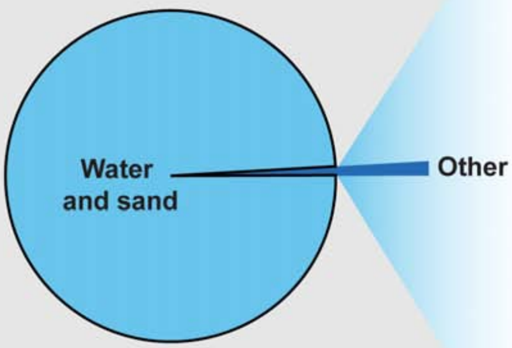
[20]Stresses in the formation generally define a maximum and minimum stress direction that influence the direction a fracture will grow.

Figure 2: Perforating Tool

Source: GAO.

Fracturing fluids are tailored to site specific conditions, such as shale thickness, stress, compressibility, and rigidity. As such, the chemical additives used in a fracture treatment vary. Operators may use computer models that consider local conditions to design site-specific hydraulic fluids. The water, chemicals, and proppant used in fracturing fluid are typically stored on-site in separate tanks and blended just before they are injected into the well. Figure 3 provides greater detail about some chemicals commonly used in fracturing.

Figure 3: Examples of Common Ingredients Found in Fracturing Fluid



Additive type	Use	Main compound
Acid	Removes near well damage	Hydrochloric acid
Biocide	Controls bacterial growth	Glutaraldehyde
Breaker	Delays breakdown of the geling agent	Ammonium persulfate
Corrosion inhibitor	Prevent corrosion of pipe	N,n-dimethyl formamide
Crosslinker	Maintains fluid viscosity as temperature increases	Borate salts
Friction reducers	Decreases pumping friction	Polyacrylamide
Gelling agents	Improves proppant placement	Guar gum
KCl	Creates a brine carrier fluid	Potassium chloride
Oxygen scavenger	Prevents corrosion of well tubulars	Ammonium bisulfite
pH adjusting agent	Adjusts the pH of fluid to maintain the effectiveness of other components	Sodium carbonate
Scale inhibitor	Prevents scale deposits in the pipe	Ethylene glycol
Surfactant	Winterizing agent	Isopropanol

Sources: Department of Energy and Groundwater Protection Council.

The operator pumps the fracturing fluid into the wellbore at pressures high enough to force the fluid through the perforations into the surrounding formation—which can be shale, coalbeds, or tight sandstone—expanding existing fractures and creating new ones in the process. After the fractures are created, the operator reduces the pressure. The proppant stays in the formation to hold open the fractures and allow the release of oil and gas. Some of the fracturing fluid that was injected into the well will return to the surface (commonly referred to as flowback) along with water that occurs naturally in the oil- or gas-bearing formation—collectively referred to as produced water. The produced water is brought to the surface and collected by the operator, where it can be stored on-site in impoundments, injected into underground wells, transported to a wastewater treatment plant, or reused by the operator in other ways.[21] Given the length of horizontal wells, hydraulic fracturing is often conducted in stages, where each stage focuses on a limited linear section and may be repeated numerous times.

Once a well is producing oil or natural gas, equipment and temporary infrastructure associated with drilling and hydraulic fracturing operations is no longer needed and may be removed, leaving only the parts of the infrastructure required to collect and process the oil or gas and ongoing produced water. Operators may begin to reclaim the part of the site that will not be used by restoring the area to predevelopment conditions. Throughout the producing life of an oil or gas well, the operator may find it necessary to periodically restimulate the flow of oil or gas by repeating the hydraulic fracturing process. The frequency of such activity depends on the characteristics of the geologic formation and the economics of the individual well. If the hydraulic fracturing process is repeated, the site and surrounding area will be further affected by the required infrastructure, truck transport, and other activity associated with this process.

Regulatory Framework

Shale oil and gas development, like conventional onshore oil and gas production, is governed by a framework of federal, state, and local laws and regulations. Most shale development in the near future is expected to occur on nonfederal lands and, therefore, states will typically take the lead in regulatory activities. However, in some cases, federal agencies oversee shale oil and gas development. For example, BLM oversees shale oil and gas development on federal lands. In large part, the federal laws, regulations, and permit requirements that apply to conventional onshore oil and gas exploration and production activities also apply to shale oil and gas development.

- *Federal*. A number of federal agencies administer laws and regulations that apply to various phases of shale oil and gas development. For example, BLM manages federal lands and approximately 700 million acres of federal subsurface minerals, also known as the federal mineral estate. EPA administers and enforces key federal laws, such as the Safe Drinking Water Act, to protect

[21]Underground injection is the predominant practice for disposing of produced water. In addition to underground injection, a limited amount of produced water is managed by discharging it to surface water, storing it in surface impoundments, and reusing it for irrigation or hydraulic fracturing.

human health and the environment. Other federal land management agencies, such as the U.S. Department of Agriculture's Forest Service and the Department of the Interior's Fish and Wildlife Service, also manage federal lands, including shale oil and gas development on those lands.

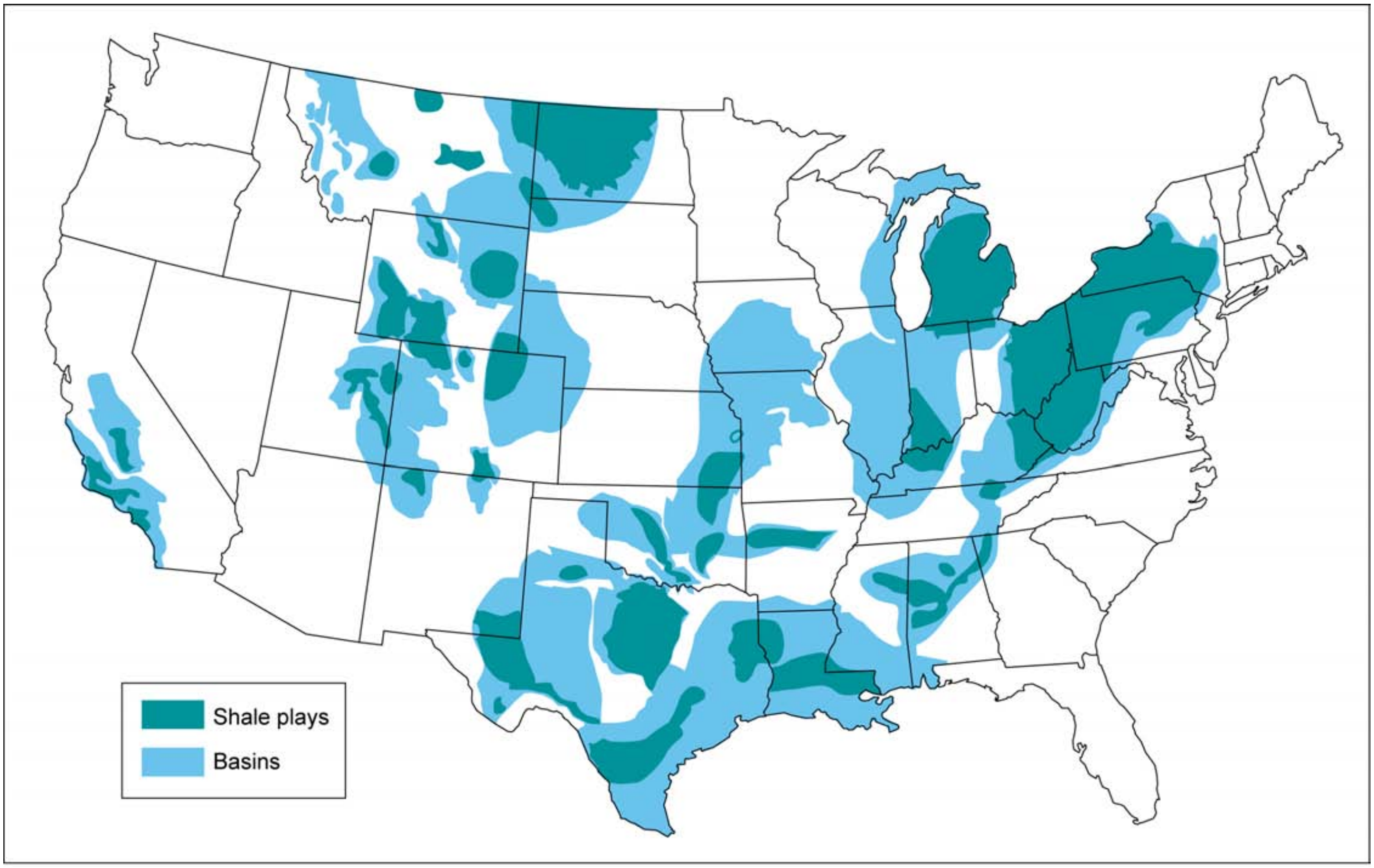
- *State.* State agencies implement and enforce many of the federal environmental regulations and may also have their own set of state laws covering shale oil and gas development.
- *Other.* Additional requirements regarding shale oil and gas operations may be imposed by various levels of government for specific locations. Entities such as cities, counties, tribes, and regional water authorities may set additional requirements that affect the location and operation of wells.

GAO is conducting a separate and more detailed review of the federal and state laws and regulations that apply to unconventional oil and gas development, including shale oil and gas.

Location of Shale Oil and Gas in the United States

Shale oil and gas are found in shale plays—a set of discovered or undiscovered oil and natural gas accumulations or prospects that exhibit similar geological characteristics—on private, state-owned, and federal lands across the United States. Shale plays are located within basins, which are large-scale geological depressions, often hundreds of miles across, that also may contain other oil and gas resources. Figure 4 shows the location of shale plays and basins in the contiguous 48 states.

Figure 4: Shale Plays and Basins in the Contiguous 48 States



Sources: Energy Information Administration (shale location data); (map) copyright © Corel Corp., all rights reserved.

A shale play can be developed for oil, natural gas, or both. In addition, a shale gas play may contain "dry" or "wet" natural gas. Dry natural gas is a mixture of hydrocarbon compounds that exists as a gas both underground in the reservoir and during production under standard temperature and pressure conditions. Wet natural gas contains natural gas liquids, or the portion of the hydrocarbon resource that exists as a gas when in natural underground reservoir conditions but that is liquid at surface conditions. The natural gas liquids are typically propane, butane, and ethane and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants. Operators may then sell the natural gas liquids, which may give wet shale gas plays an economic advantage over dry gas plays. Another advantage of liquid petroleum and natural gas liquids is that they can be transported more easily than natural gas. This is because, to bring natural gas to markets and consumers, companies must build an extensive network of gas pipelines. In areas where gas pipelines are not extensive, natural gas produced along with liquids is often vented or flared.

Estimating the Size of Shale Oil and Gas Resources

Estimating the size of shale oil and gas resources serves a variety of needs for consumers, policymakers, land and resource managers, investors, regulators, industry planners, and others. For example, federal and state governments may use resource estimates to estimate future revenues and establish energy, fiscal, and national security policies. The petroleum industry and the financial community use resource estimates to establish corporate strategies and make investment decisions.

A clear understanding of some common terms used to generally describe the size and scope of oil and gas resources is needed to determine the relevance of a given estimate. For an illustration of how such terms describe the size and scope of shale oil and gas, see figure 5.

The most inclusive term is in-place resource. The in-place resource represents all oil or natural gas contained in a formation without regard to technical or economic recoverability. In-place resource estimates are sometimes very large numbers, but often only a small proportion of the total amount of oil or natural gas in a formation may ever be recovered. Oil and gas resources that are in-place, but not technically recoverable at this time may, in the future, become technically recoverable.

Technically recoverable resources are a subset of in-place resources that include oil or gas, including shale oil and gas that is producible given available technology. Technically recoverable resources include those that are economically producible and those that are not. Estimates of technically recoverable resources are dynamic, changing to reflect the potential of extraction technology and knowledge about the geology and composition of geologic formations. According to the National Petroleum Council,[22] technically recoverable resource estimates usually increase

[22]The National Petroleum Council is a federally chartered and privately funded advisory committee that advises, informs, and makes recommendations to the Secretary of Energy on oil and natural gas matters.

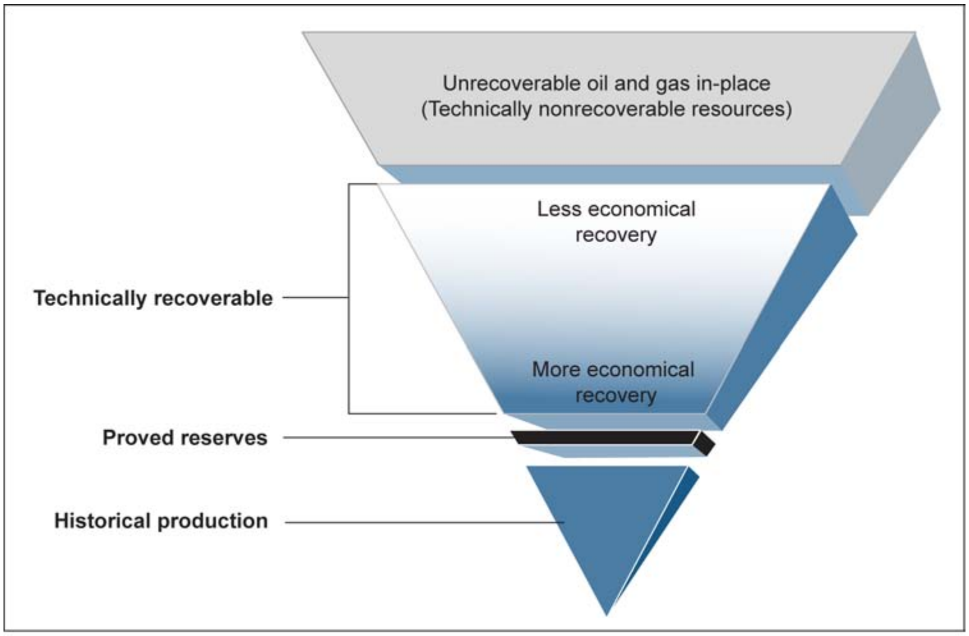
over time because of the availability of more and better data, or knowledge of how to develop a new play type (such as shale formations).

Proved reserve estimates are more precise than technically recoverable resources and represent the amount of oil and gas that have been discovered and defined, typically by drilling wells or other exploratory measures, and which can be economically recovered within a relatively short time frame. Proved reserves may be thought of as the “inventory” that operators hold and define the quantity of oil and gas that operators estimate can be recovered under current economic conditions, operating methods, and government regulations. Estimates of proved reserves increase as oil and gas companies make new discoveries and report them to the government; oil and gas companies can increase their reserves as they develop already-discovered fields and improve production technology. Reserves decline as oil and gas reserves are produced and sold. In addition, reserves can change as prices and technologies change. For example, technology improvements that enable operators to extract more oil or gas from existing fields can increase proved reserves. Likewise, higher prices for oil and gas may increase the amount of proved reserves because more resources become financially viable to extract.[23] Conversely, lower prices may diminish the amount of resources likely to be produced, reducing proved reserves.

Historical production refers to the total amount of oil and gas that has been produced up to the present. Because these volumes of oil and gas have been measured historically, this is the most precise information available as it represents actual production amounts.

[23]For example, secondary recovery operations can be costly (such as using a well to inject water into an oil reservoir and push any remaining oil to operating wells), but the costs may be justified if prices are high enough.

Figure 5: Common Terminology to Describe the Size and Scope of Shale Oil and Gas



Sources: GAO; based on illustration by the Congressional Research Service.

Note: This illustration is not necessarily to scale because all volumes, except historical production, are subject to significant uncertainty.

Certain federal agencies have statutory responsibility for collecting and publishing authoritative statistical information on various types of energy sources in the United States. EIA collects, analyzes, and disseminates independent and impartial energy information, including data on shale oil and gas resources. Under the Energy Policy and Conservation Act of 2000, as amended, USGS estimates onshore undiscovered technically recoverable oil and gas resources in the United States.[24] USGS has conducted a number of national estimates of undiscovered technically recoverable oil and natural gas resources over several decades. USGS geologists and other experts estimate undiscovered oil and gas—that is, oil and gas that has not been proven to be present by oil and gas companies—based on geological survey data and other information about

[24]Pub. L. No. 106-469 § 604 (2000), 114 Stat. 2029, 2041-42, codified, as amended, at 42 U.S.C. § 6217.

the location and size of different geological formations across the United States. In addition to EIA and USGS, experts from industry, academia, federal advisory committees, private consulting firms, and professional societies also estimate the size of the resource.

Domestic Shale Oil and Gas Estimates and Production

Estimates of the size of shale oil and gas resources in the United States have increased over time as has the amount of such resources produced from 2007 through 2011. Specifically, over the last 5 years, estimates of (1) technically recoverable shale oil and gas and (2) proved reserves of shale oil and gas have increased, as technology has advanced and more shale has been drilled. In addition, domestic shale oil and gas production has experienced substantial growth in recent years.

Estimates of Technically Recoverable Shale Oil and Gas Resources

EIA, USGS, and the Potential Gas Committee have increased their estimates of the amount of technically recoverable shale oil and gas over the last 5 years, which could mean an increase in the nation's energy portfolio; however, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. The estimates are from different organizations and vary somewhat because they were developed at different times and using different data, methods, and assumptions, but estimates from all of these organizations have increased over time, indicating that the nation's shale oil and gas resources may be substantial. For example, according to estimates and reports we reviewed, assuming current consumption levels without consideration of a specific market price for future gas supplies, the amount of domestic technically recoverable shale gas could provide enough natural gas to supply the nation for the next 14 to 100 years. The increases in estimates can largely be attributed to improved geological information about the resources, greater understanding of production levels, and technological advancements.

Estimates of Technically Recoverable Shale Oil Resources

In the last 2 years, EIA and USGS provided estimates of technically recoverable shale oil.[25] Each of these estimates increased in recent years as follows:

- In 2012, EIA estimated that the United States possesses 33 billion barrels of technically recoverable shale oil,[26] mostly located in four shale formations—the Bakken in Montana and North Dakota; Eagle Ford in Texas; Niobrara in Colorado, Kansas, Nebraska, and Wyoming; and the Monterey in California.
- In 2011, USGS estimated that the United States possesses just over 7 billion barrels of technically recoverable oil in shale and tight sandstone formations. The estimate represents a more than threefold increase from the agency's estimate in 2006. However, there are several shale plays that USGS has not evaluated for shale oil because interest in these plays is relatively new. According to USGS officials, these shale plays have shown potential for production in recent years and may contain additional shale oil resources. Table 1 shows USGS' 2006 and 2011 estimates and EIA's 2011 and 2012 estimates.

Table 1: USGS and EIA Estimates of Total Remaining Technically Recoverable U.S. Oil Resources

Barrels of oil in billions

	USGS		EIA	
	2006	**2011**	**2011**	**2012**
Estimated technically recoverable shale oil and tight sandstone resources	2	7	32	33
Estimated technically recoverable oil resources other than shale[a]	142	133	187	201

Source: GAO analysis of EIA and USGS data.

[25]As noted previously, for the purposes of this report, we use the term "shale oil" to refer to oil from shale and other tight formations, which is recoverable by hydraulic fracturing and horizontal drilling techniques and is described by others as "tight oil." Shale oil and tight oil are extracted in the same way, but differ from "oil shale." Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

[26]Comparatively, the United States currently consumes about 7 billion barrels of oil per year, about half of which are imported from foreign sources.

[a]Includes estimates for conventional offshore oil and gas, as well as natural gas liquids. In addition, the USGS estimates for 2006 and 2011 include a 2006 estimate of technically recoverable offshore conventional oil resources totaling 86 billion barrels of oil and natural gas liquids from the former Minerals Management Service, which has since been reorganized into the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement.

Overall, estimates of the size of technically recoverable shale oil resources in the United States are imperfect and highly dependent on the data, methodologies, model structures, and assumptions used. As these estimates are based on data available at a given point in time, they may change as additional information becomes available. Also these estimates depend on historical production data as a key component for modeling future supply. Because large-scale production of oil in shale formations is a relatively recent activity, their long-term productivity is largely unknown. For example, EIA estimated that the Monterey Shale in California may possess about 15.4 billion barrels of technically recoverable oil. However, without a longer history of production, the estimate has greater uncertainty than estimates based on more historical production data. At this time, USGS has not yet evaluated the Monterey Shale play.

Estimates of Technically Recoverable Shale Gas Resources

The amount of technically recoverable shale gas resources in the United States has been estimated by a number of organizations, including EIA, USGS, and the Potential Gas Committee (see fig. 6). Their estimates were as follows:

- In 2012, EIA estimated the amount of technically recoverable shale gas in the United States at 482 trillion cubic feet.[27] This represents an increase of 280 percent from EIA's 2008 estimate.
- In 2011, USGS reported that the total of its estimates for the shale formations the agency evaluated in all previous years[28] shows the

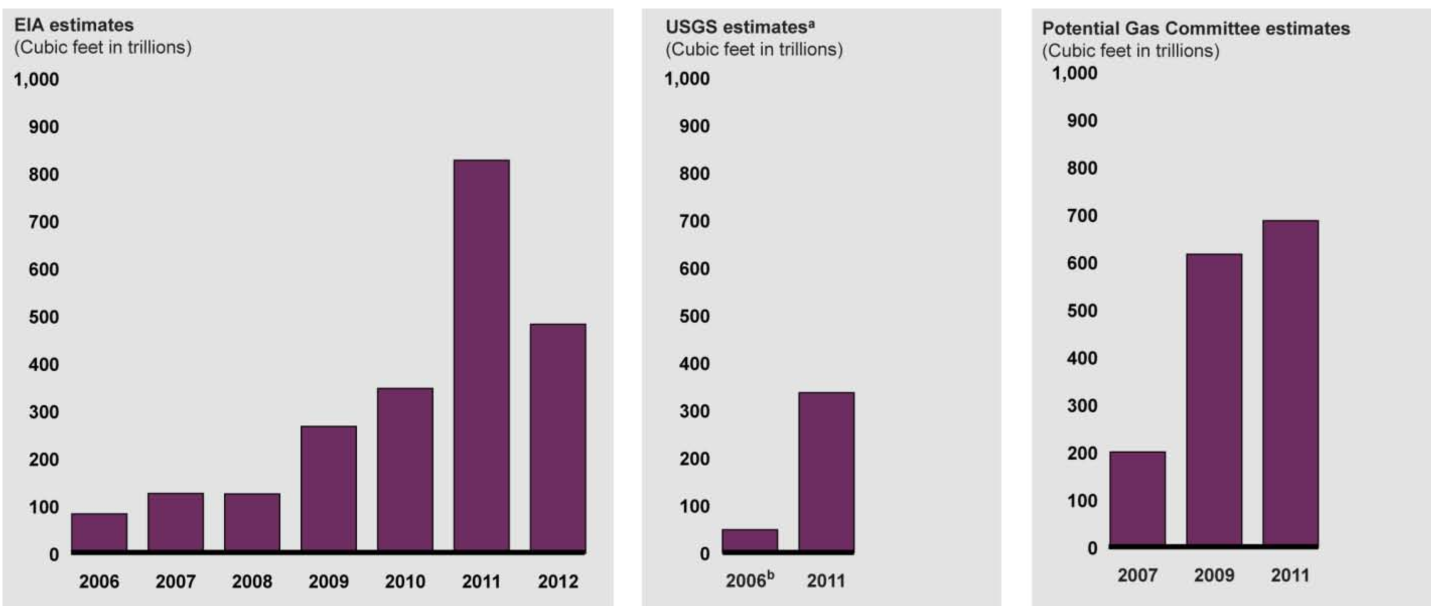
[27]EIA estimates are based on natural gas production data from 2 years prior to the reporting year; for example, EIA's 2012 estimate is based on 2010 data; the date cited here reflects the fact that EIA reported this latest estimate in 2012.

[28]USGS estimates are based on updated data in a few—but not all—individual geological areas, combined with data from other areas from all previous years. Each year USGS estimates new information for a few individual geological areas. For example, the 2011 USGS estimate includes updated 2011 data for the Appalachian Basin, the Anadarko Basin, and the Gulf Coast, combined with estimates for all other areas developed before 2011. See appendix III for additional information on USGS estimates. The date cited here reflects the fact that USGS reported this latest estimate in 2011.

amount of technically recoverable shale gas in the United States at about 336 trillion cubic feet. This represents an increase of about 600 percent from the agency's 2006 estimate.

- In 2011, the Potential Gas Committee estimated the amount of technically recoverable shale gas in the United States at about 687 trillion cubic feet.[29] This represents an increase of 240 percent from the committee's 2007 estimate.

Figure 6: Estimates of Technically Recoverable Shale Gas from EIA, USGS, and the Potential Gas Committee (2006 through 2012)



Sources: GAO analysis of EIA, Potential Gas Commitee, and USGS estimates.

Notes: Natural gas is generally priced and sold in thousand cubic feet (abbreviated Mcf, using the Roman numeral for 1,000). Units of a trillion cubic feet (Tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. One Tcf is enough natural gas to heat 15 million homes for 1 year or fuel 12 million natural gas-fired vehicles for 1 year. In 2012, EIA reduced its estimate of technically recoverable shale gas in the Marcellus Shale by about 67 percent. According to EIA officials, the decision to revise the estimate was based primarily on the availability of new production data, which was highlighted by the release of the USGS

[29]Potential Gas Committee estimates are based on natural gas production data from the previous year; for example, committee's 2011 estimate is based on 2010 data. The date cited here reflects the fact that the Potential Gas Committee reported this latest estimate in 2011.

estimate. In 2011, EIA used data from a contractor to estimate that the Marcellus Shale possessed about 410 trillion cubic feet of technically recoverable gas. After EIA released its estimates in 2011, USGS released its first estimate of technically recoverable gas in the Marcellus in almost 10 years. USGS estimated that there were 84 trillion cubic feet of natural gas in the Marcellus—which was 40 times more than its previous estimate reported in 2002 but significantly less than EIA's estimate. In 2012, EIA announced that it was revising its estimate of the technically recoverable gas in the Marcellus Shale from 410 to 141 trillion cubic feet. EIA reported additional details about its methodology and data in June 2012. See U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2012, With Projections to 2035 (DOE/EIA-0383 [2012], Washington, D.C., June 25, 2012).

[a]The 2006 USGS estimate of about 54 trillion cubic feet represents those assessments that had been done up to the end of 2006. As such, the estimate is partially dependent on how the agency scheduled basin studies and assessments from 2000 through 2006, rather than purely on changes in USGS views of resource potential since 2006.

[b]The Potential Gas Committee did not report separate estimates of shale gas until 2007 and has updated this estimate every 2 years since then.

In addition to the estimates from the three organizations we reviewed, operators and energy forecasting consultants prepare their own estimates of technically recoverable shale gas to plan operations or for future investment. In September 2011, the National Petroleum Council aggregated data on shale gas resources from over 130 industry, government, and academic groups and estimated that approximately 1,000 trillion cubic feet of shale gas is available for production domestically. In addition, private firms that supply information to the oil and gas industry conduct assessments of the total amount of technically recoverable natural gas. For example, ICF International, a consulting firm that provides information to public- and private-sector clients, estimated in March 2012 that the United States possesses about 1,960 trillion cubic feet of technically recoverable shale gas.

Based on estimates from EIA, USGS, and the Potential Gas Committee, five shale plays—the Barnett, Haynesville, Fayetteville, Marcellus, and Woodford—are estimated to possess about two-thirds of the total estimated technically recoverable gas in the United States (see table 2).

Table 2: Estimated Technically Recoverable Shale Gas Resources, by Play

Shale play	Location	Technically recoverable gas, in trillion cubic feet (Tcf)
Barnett	North Texas	43-53
Fayetteville	Arkansas	13-110
Haynesville	Louisiana and East Texas	66-110
Marcellus	Northeast United States	84-227[a]
Woodford	Oklahoma	11-27

Sources: GAO analysis of EIA, USGS, and Potential Gas Committee data.

Note: The estimated technically recoverable gas shown here represents the range of estimates for these plays determined by EIA, USGS, and the Potential Gas Committee.

[a]This estimate of the Marcellus also includes estimated shale gas from other nearby lands in the Appalachian area; but, according to an official for the estimating organization, the Marcellus Shale is the predominant source of gas in the basin.

As with estimates for technically recoverable shale oil, estimates of the size of technically recoverable shale gas resources in the United States are also highly dependent on the data, methodologies, model structures, and assumptions used and may change as additional information becomes available. These estimates also depend on historical production data as a key component for modeling future supply. Because most shale gas wells generally were not in place until the last few years, their long-term productivity is untested. According to a February 2012 report released by the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, production in emerging shale plays has been concentrated in areas with the highest known gas production rates, and many shale plays are so large that most of the play has not been extensively tested.[30] As a result, production rates achieved to date may not be representative of future production rates across the formation. EIA reports that experience to date shows production rates from neighboring shale gas wells can vary by as much as a factor of 3 and that production rates for different wells in the same formation can vary by as much as a factor of 10. Most gas companies estimate that production in a given well will drop sharply after the first few years and

[30]The Sustainable Investments Institute (Si2) is a nonprofit membership organization founded in 2010 to conduct research and publish reports on organized efforts to influence corporate behavior. The Investor Responsibility Research Center Institute is a nonprofit organization established in 2006 that provides information to investors.

then level off, continuing to produce gas for decades, according to the Sustainable Investments Institute and the Investor Responsibility Research Center Institute.

Estimates of Proved Reserves of Shale Oil and Gas

Estimates of proved reserves of shale oil and gas increased from 2007 to 2009. Operators determine the size of proved reserves based on information collected from drilling, geological and geophysical tests, and historical production trends. These are also the resources operators believe they will develop in the short term—generally within the next 5 years—and assume technological and economic conditions will remain unchanged.

Estimates of proved reserves of shale oil. EIA does not report proved reserves of shale oil separately from other oil reserves; however, EIA and others have noted an increase in the proved reserves of oil in the nation, and federal officials attribute the increase, in part, to oil from shale and tight sandstone formations. For example, EIA reported in 2009 that the Bakken Shale in North Dakota and Montana drove increases in oil reserves, noting that North Dakota proved reserves increased over 80 percent from 2008 through 2009.

Estimates of proved reserves of shale gas. According to data EIA collects from about 1,200 operators, proved reserves of shale gas have grown from 23 trillion cubic feet in 2007 to 61 trillion cubic feet in 2009, or an increase of 160 percent.[31] More than 75 percent of the proved shale gas reserves are located in three shale plays—the Barnett, Fayetteville, and the Haynesville.

Shale Oil and Gas Production

From 2007 through 2011, annual production of shale oil and gas has experienced significant growth. Specifically, shale oil production increased more than fivefold, from 39 to about 217 million barrels over this 5-year period, and shale gas production increased approximately fourfold, from 1.6 to about 7.2 trillion cubic feet, over the same period. To

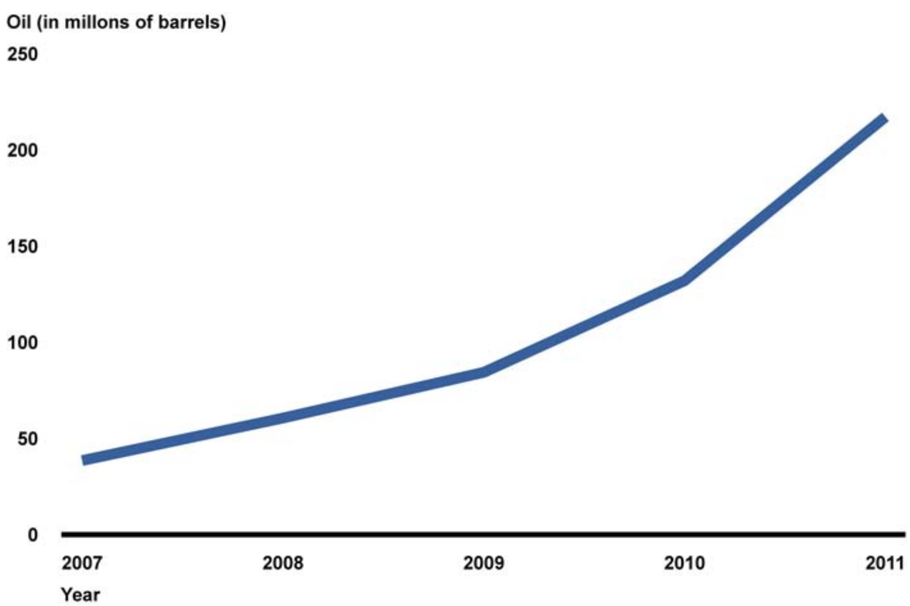
[31]Reserves are key information for assessing the net worth of an operator. Oil and gas companies traded on the U.S. stock exchange are required to report their reserves to the Securities and Exchange Commission. According to an EIA official, EIA reports a more complete measure of oil and gas reserves because it receives reports of proved reserves from both private and publically held companies.

put this shale production into context, the annual domestic consumption of oil in 2011 was about 6,875 million barrels of oil, and the annual consumption of natural gas was about 24 trillion cubic feet. The increased shale oil and gas production was driven primarily by technological advances in horizontal drilling and hydraulic fracturing that made more shale oil and gas development economically viable.

Shale Oil Production

Annual shale oil production in the United States increased more than fivefold, from about 39 million barrels in 2007 to about 217 million barrels in 2011, according to data from EIA (see fig. 7).[32] This is because new technologies allowed more oil to be produced economically, and because of recent increases in the price for liquid petroleum that have led to increased investment in shale oil development.

Figure 7: Estimated Production of Shale Oil from 2007 through 2011 (in millions of barrels of oil)



Source: GAO analysis of EIA data.

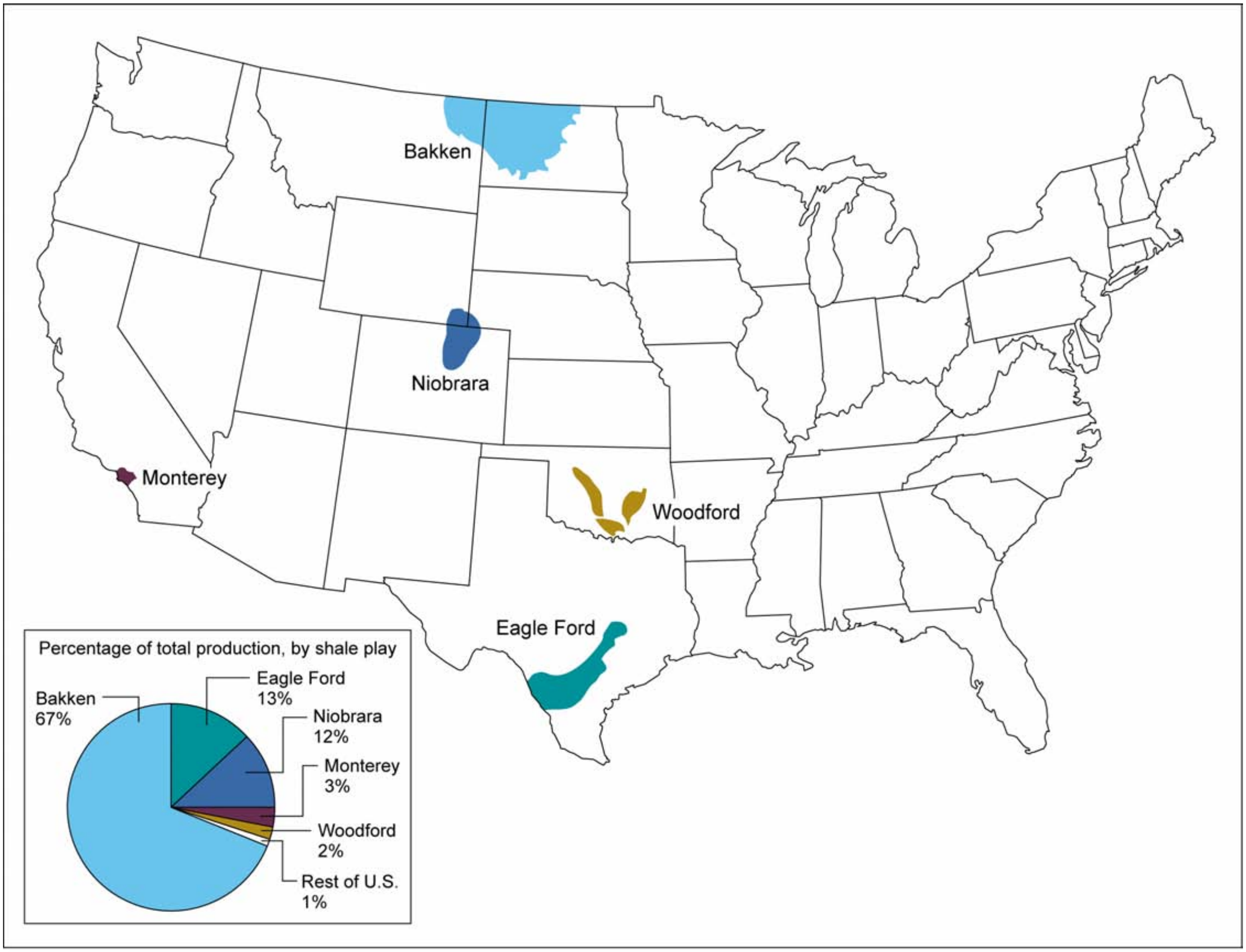
[32]As noted previously, for the purposes of this report, we use the term "shale oil" to refer to oil from shale and other tight formations, which is recovered by hydraulic fracturing and horizontal drilling and is described by others as "tight oil." Shale oil and tight oil are extracted in the same way, but differ from "oil shale." Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

In total, during this period, about 533 million barrels of shale oil was produced. More than 65 percent of the oil was produced in the Bakken Shale (368 million barrels; see fig. 8).[33] The remainder was produced in the Niobrara (62 million barrels), Eagle Ford (68 million barrels), Monterey (18 million barrels), and the Woodford (9 million barrels). To put this in context, shale oil production from these plays in 2011 constituted about 8 percent of U.S. domestic oil consumption, according to EIA data.[34]

[33]EIA provided us with estimated shale oil production data from a contractor, HPDI LLC., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale oil production. EIA has not routinely reported shale oil production data separately from oil production.

[34]In addition to production from these shale oil plays, EIA officials told us that oil was produced from “tight oil” plays such as the Austin Chalk. The technology for producing tight oil is the same as for shale oil, and EIA uses the term “tight oil” to encompass both shale oil and tight oil that are developed with the same type of technology. In addition, EIA officials added that the shale oil data presented here is approximate because the data comes from a sample of similar plays. Overtime, this production data will become more precise as more data becomes available to EIA.

Figure 8: Shale Oil Production, by Shale Play (from 2007 through 2011)

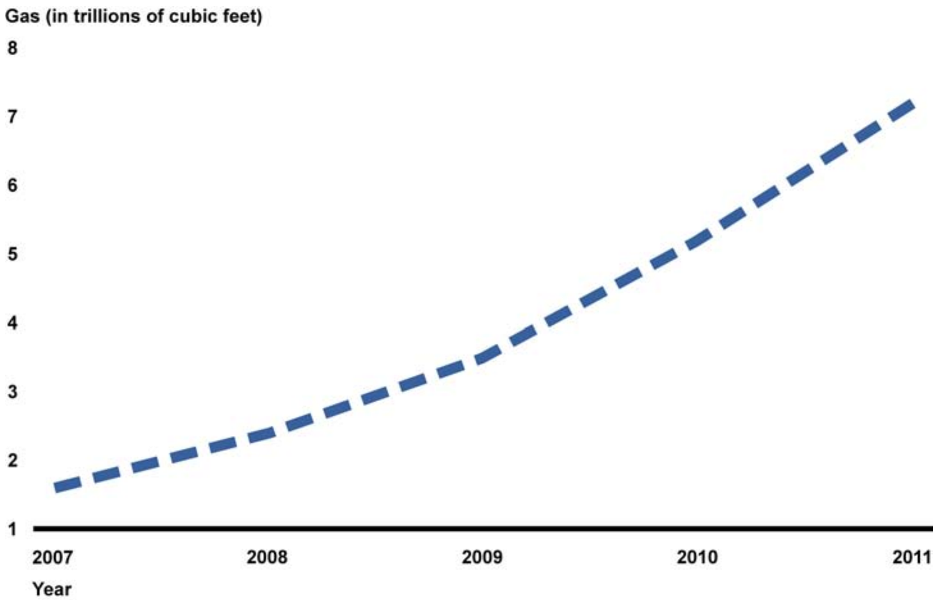


Sources: GAO analysis of EIA data; (map) copyright © Corel Corp., all rights reserved.

Shale Gas Production

Shale gas production in the United States increased more than fourfold, from about 1.6 trillion cubic feet in 2007 to about 7.2 trillion cubic feet in 2011, according to estimated data from EIA (see fig. 9).[35]

Figure 9: Estimated Production of Shale Gas from 2007 through 2011 (in trillions of cubic feet)



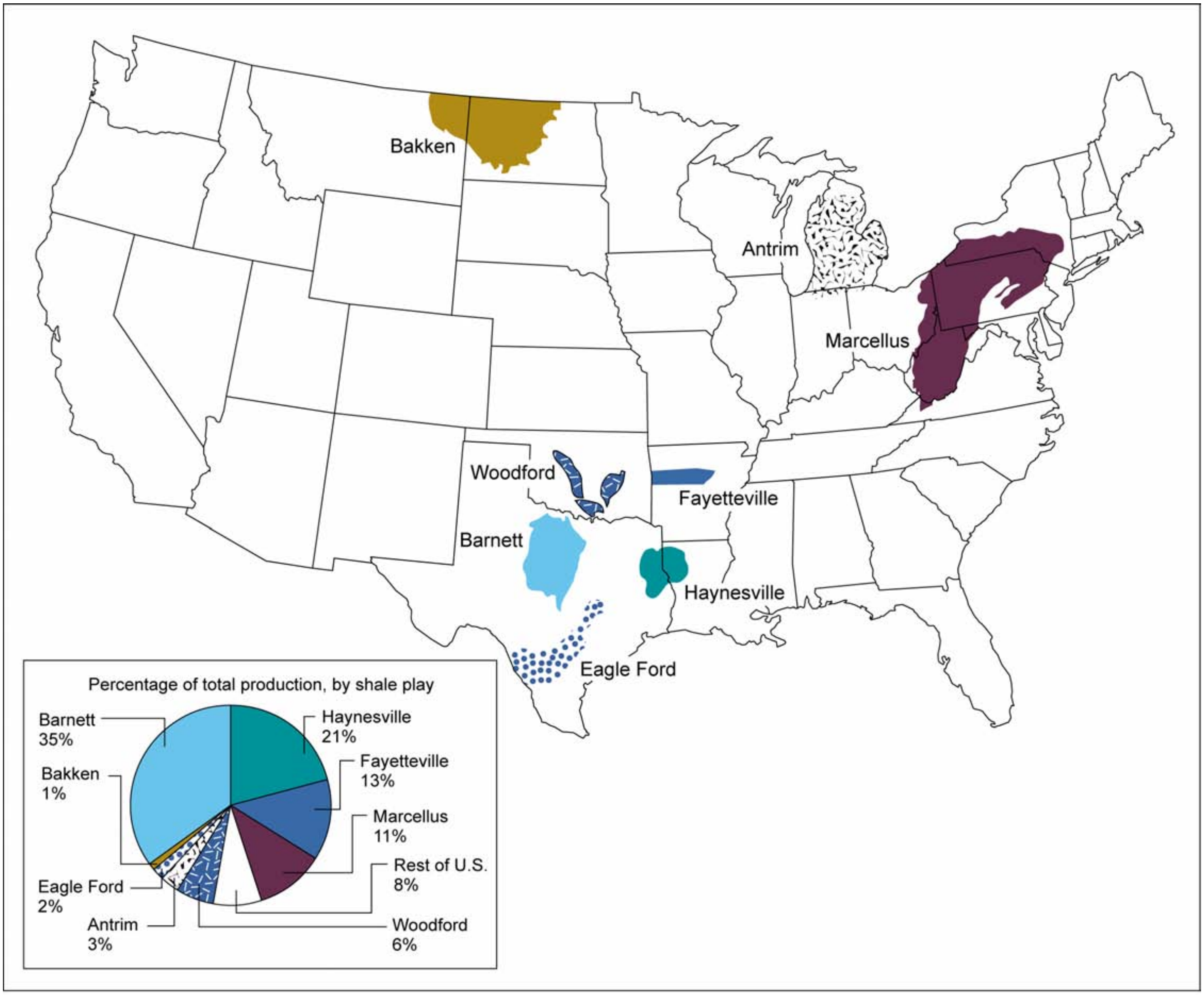
Source: GAO analysis of EIA data.

In total, during this period, about 20 trillion cubic feet of shale gas was produced—representing about 300 days of U.S. consumption, based on 2011 consumption rates. More than 75 percent of the gas was produced in four shale plays—the Barnett, Marcellus, Fayetteville, and Haynesville (see fig.10). From 2007 through 2011, shale gas' contribution to the nation's total natural gas supply grew from about 6 percent in 2007 to approximately 25 percent in 2011 and is projected, under certain assumptions, to increase to 49 percent by 2035, according to an EIA report. Overall production of shale gas increased from calendar years 2007 through 2011, but production of natural gas on federal and tribal

[35]EIA provided us with estimated shale gas production data from a contractor, Lippman Consulting, Inc., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale gas production. EIA has separately reported shale gas production data using reports from states for the years 2008 and 2009.

lands—including shale gas and natural gas from all other sources—decreased by about 17 percent, according to an EIA report. EIA attributes this decrease to several factors, including the location of shale formations—which, according to an EIA official, appear to be predominately on nonfederal lands.

Figure 10: Shale Gas Production, by Shale Play (from 2007 through 2011)



Sources: GAO analysis of EIA data; (map) copyright © Corel Corp., all rights reserved.

The growth in production of shale gas has increased the overall supply of natural gas in the U.S. energy market. Since 2007, increased shale gas production has contributed to lower prices for consumers, according to EIA and others.[36] These lower prices create incentives for wider use of natural gas in other industries. For example, several reports by government, industry, and others have observed that if natural gas prices remain low, natural gas is more likely to be used to power cars and trucks in the future. In addition, electric utilities may build additional natural gas-fired generating plants as older coal plants are retired. At the same time, some groups have expressed concern that greater reliance on natural gas may reduce interest in developing renewable energy.

Development of Wet Gas

EIA reported that operators have recently moved away from the development of shale plays that are primarily dry gas in favor of developing plays with higher concentrations of natural gas liquids. At current natural gas prices, natural gas liquids are a much more valuable product than dry gas. This is because the end products and byproducts of natural gas liquids contain more energy per unit of volume and have uses beyond heating and power generation and may be converted into products that can be more easily transported and traded in the global market. Shale plays with significant natural gas liquids include the Eagle Ford and Marcellus.

The greater availability of domestic shale gas has also decreased the need for natural gas imports. For example, EIA has noted that volumes of natural gas imported into the United States have fallen in recent years—in 2007, the nation imported 16 percent of the natural gas consumed and in 2010, the nation imported 11 percent—as domestic shale gas production has increased. This trend is also illustrated by an increase in applications for exporting liquefied natural gas to other countries. In its 2012 annual energy outlook, EIA predicted that, under certain scenarios, the United States will become a net exporter of natural gas by about 2022.[37]

Shale Oil and Gas Development Pose Environmental and Public Health Risks, but the Extent is Unknown and Depends on Many Factors

Developing oil and gas resources—whether conventional or from shale formations—poses inherent environmental and public health risks, but the extent of risks associated with shale oil and gas development is unknown, in part, because the studies we reviewed do not generally take into account potential long-term, cumulative effects. In addition, the severity of adverse effects depend on various location- and process-specific factors, including the location of future shale oil and gas development and the rate at which it occurs, geology, climate, business practices, and regulatory and enforcement activities.

[36]According to a 2012 report from the Bipartisan Policy Center, natural gas prices declined roughly 37 percent from February 2008 to January 2010.

[37]Department of Energy, Energy Information Administration, *Annual Energy Outlook 2012, With Projections to 2035*, DOE/EIA-0383 (Washington, D.C.: June 25, 2012).

Shale Oil and Gas Development Pose Risks to Air, Water, Land and Wildlife

Oil and gas development, which includes development from shale formations, poses inherent risks to air quality, water quantity, water quality, and land and wildlife.

Air Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to air quality. These risks are generally the result of engine exhaust from increased truck traffic, emissions from diesel-powered pumps used to power equipment, intentional flaring or venting of gas for operational reasons, and unintentional emissions of pollutants from faulty equipment or impoundments.

Construction of the well pad, access road, and other drilling facilities requires substantial truck traffic, which degrades air quality. According to a 2008 National Park Service report, an average well, with multistage fracturing, can require 320 to 1,365 truck loads to transport the water, chemicals, sand, and other equipment—including heavy machinery like bulldozers and graders—needed for drilling and fracturing. The increased traffic creates a risk to air quality as engine exhaust that contains air pollutants such as nitrogen oxides and particulate matter that affect public health and the environment are released into the atmosphere.[38] Air quality may also be degraded as fleets of trucks traveling on newly graded or unpaved roads increase the amount of dust released into the air—which can contribute to the formation of regional haze.[39] In addition to the dust, silica sand (see fig. 11)—commonly used as proppant in the hydraulic fracturing process—may pose a risk to human health, if not properly handled. According to a federal researcher from the Department of Health and Human Services, uncontained sand particles and dust pose threats to workers at hydraulic fracturing well sites. The official stated that particles from the sand, if not properly contained by dust control mechanisms, can lodge in the lungs and potentially cause silicosis.[40]

[38]Nitrogen oxides are regulated pollutants commonly known as NOx that, among other things, contribute to the formation of ozone and have been linked to respiratory illness, decreased lung function, and premature death. Particulate matter is a ubiquitous form of air pollution commonly referred to as soot. GAO, *Diesel Pollution: Fragmented Federal Programs That Reduce Mobile Source Emissions Could Be Improved*, GAO-12-261 (Washington, D.C.: Feb. 7, 2012).

[39]T. Colborn, C. Kwiatkowski, K. Schultz, and M. Bachran, “Natural Gas Operations From a Public Health Perspective,” *International Journal of Human & Ecological Risk Assessment* 17, no. 5 (2011).

[40]Silicosis is an incurable lung disease caused by inhaling fine dusts of silica sand.

The researcher expects to publish the results of research on public health risks from proppant later in 2012.

Figure 11: Silica Sand Proppant

Source: GAO.

Use of diesel engines to supply power to drilling sites also degrades air quality. Shale oil and gas drilling rigs require substantial power to drill and case wellbores to the depths of shale formations. This power is typically provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale—generating additional exhaust. In addition, other equipment used during operations—including pneumatic valves and dehydrators—contribute to air emissions. For example, natural gas powers switches that turn valves on and off in the production system. Each time a valve turns on or off, it “bleeds” a small amount of gas into the air. Some of these pneumatic valves vent gas continuously. A dehydrator circulates the chemical glycol to absorb moisture in the gas but also absorbs small volumes of gas. The absorbed gas vents to the atmosphere when the water vapor is released from the glycol.[41]

Releases of natural gas during the development process also degrade air quality. As part of the process to develop shale oil and gas resources, operators flare or vent natural gas for a number of operational reasons, including lowering the pressure to ensure safety or when operators purge water or hydrocarbon liquids that collect in wellbores to maintain proper well function. Flaring emits carbon dioxide, and venting releases methane and volatile organic compounds. Venting and flaring are often a necessary part of the development process but contribute to greenhouse gas emissions.[42] According to EPA analysis, natural gas well completions involving hydraulic fracturing vent approximately 230 times more natural gas and volatile organic compounds than natural gas well completions that do not involve hydraulic fracturing.[43] As we reported in July 2004, in addition to the operational reasons for flaring and venting, in areas where the primary purpose of drilling is to produce oil, operators flare or vent associated natural gas because no local market exists for the gas and transporting to a market may not be economically feasible.[44] For example, according to EIA, in 2011, approximately 30 percent of North Dakota's natural gas production from the Bakken Shale was flared by operators due to insufficient natural gas gathering pipelines, processing plants, and transporting pipelines. The percentage of flared gas in North Dakota is considerably higher than the national average; EIA reported that, in 2009,

[41] GAO-11-34.

[42] Methane and other chemical compounds found in the earth's atmosphere create a greenhouse effect. Under normal conditions, when sunlight strikes the earth's surface, some of it is reflected back toward space as infrared radiation or heat. Greenhouse gases such as carbon dioxide and methane impede this reflection by trapping heat in the atmosphere. While these gases occur naturally on earth and are emitted into the atmosphere, the expanded industrialization of the world over the last 150 years has increased the amount of emissions from human activity (known as anthropogenic emissions) beyond the level that the earth's natural processes can handle.

[43] EPA, Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas industry (Research Triangle Park, NC: April 2012).

[44] GAO, *Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions*, GAO-04-809 (Washington, D.C.: July 14, 2004).

less than 1 percent of natural gas produced in the United States was vented or flared.

Storing fracturing fluid and produced water in impoundments may also pose a risk to air quality as evaporation of the fluids have the potential to release contaminants into the atmosphere. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals the potential for emissions of hazardous air pollutants, in particular methanol, from the fluids stored in impoundments.

As with conventional oil and gas development, emissions can also occur as faulty equipment or accidents, such as leaks or blowouts, release concentrations of methane and other gases into the atmosphere. For example, corrosion in pipelines or improperly tightened valves or seals can be sources of emissions. In addition, according to EPA officials, storage vessels for crude oil, condensate, or produced water are significant sources of methane, volatile organic compounds and hazardous air pollutant emissions.

A number of studies we reviewed evaluated air quality at shale gas development sites. However, these studies are generally anecdotal, short-term, and focused on a particular site or geographic location. For example, in 2010, the Pennsylvania Department of Environmental Protection conducted short-term sampling of ambient air concentrations in north central Pennsylvania. The sampling detected concentrations of natural gas constituents including methane, ethane, propane, and butane in the air near Marcellus Shale drilling operations, but according to this state agency, the concentration levels were not considered significant enough to cause adverse health effects.[45]

The studies and publications we reviewed provide information on air quality conditions at a specific site at a specific time but do not provide the information needed to determine the overall cumulative effect that

[45]Methane emissions represent a waste of resources and a fractional contribution to greenhouse gas levels.

shale oil and gas activities have on air quality.[46] The cumulative effect shale oil and gas activities have on air quality will be largely determined by the amount of development and the rate at which it occurs, and the ability to measure this will depend on the availability of accurate information on emission levels. However, the number of wells that will ultimately be drilled cannot be known in advance—in part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. In addition, as we reported in 2010, data on the severity or amount of pollutants released by oil and gas development, including the amount of fugitive emissions, are limited.

Water Quantity

According to a number of studies and publications we reviewed, shale oil and gas development poses a risk to surface water and groundwater because withdrawing water from streams, lakes, and aquifers for drilling and hydraulic fracturing could adversely affect water sources.[47] Operators use water for drilling, where a mixture of clay and water (drilling mud) is used to carry rock cuttings to the surface, as well as to cool and lubricate the drill bit. Water is also the primary component of fracturing fluid. Table 3 shows the average amount of freshwater used to drill and fracture a shale oil or gas well.

Table 3: Average Freshwater Use per Well for Drilling and Hydraulic Fracturing

	Average freshwater used (in gallons)	
Shale play	**For drilling**	**For hydraulic fracturing**
Barnett	250,000	4,600,000
Eagle Ford	125,000	5,000,000
Haynesville	600,000	5,000,000
Marcellus	85,000	5,600,000
Niobrara	300,000	3,000,000

Source: GAO analysis of data reported by George King, Apache Corporation (2011).

Note: The amount of water required to hydraulically fracture a single well varies considerably as fracturing of shale oil and gas becomes dominated by more complex, multistaged fracturing activities.

[46]According to a 2008 National Park Service report, on a site-by-site basis, emissions may not be significant but on a regional basis may prove significant as states and parks manage regional ozone transport.

[47]An aquifer is an underground layer of rock or unconsolidated sand, gravel, or silt that will yield groundwater to a well or spring.

According to a 2012 University of Texas study,[48] water for these activities is likely to come from surface water (rivers, lakes, ponds), groundwater aquifers, municipal supplies, reused wastewater from industry or water treatment plants, and recycling water from earlier fracturing operations.[49] As we reported in October 2010, withdrawing water from nearby streams and rivers could decrease flows downstream, making the streams and rivers more susceptible to temperature changes—increases in the summer and decreases in the winter. Elevated temperatures could adversely affect aquatic life because many fish and invertebrates need specific temperatures for reproduction and proper development. Further, decreased flows could damage or destroy riparian vegetation. Similarly, withdrawing water from shallow aquifers—an alternative water source—could temporarily affect groundwater resources. Withdrawals could lower water levels within these shallow aquifers and the nearby streams and springs to which they are connected. Extensive withdrawals could reduce groundwater discharge to connected streams and springs, which in turn could damage or remove riparian vegetation and aquatic life. Withdrawing water from deeper aquifers could have longer-term effects on groundwater and connected streams and springs because replenishing deeper aquifers with precipitation generally takes longer.[50] Further, groundwater withdrawal could affect the amount of water available for other uses, including public and private water supplies.

Freshwater is a limited resource in some arid and semiarid regions of the country where an expanding population is placing additional demands on water. The potential demand for water is further complicated by years of drought in some parts of the country and projections of a warming climate. According to a 2011 Massachusetts Institute of Technology study,[51] the amount of water used for shale gas development is small in

[48]Charles G. Groat, Ph.D. and Thomas W. Grimshaw, Ph.D., *Fact-Based Regulation for Environmental Protection in Shale Gas Development* (Austin, Texas: The Energy Institute, The University of Texas at Austin, February, 2012).

[49]Operators are pursuing a variety of techniques and technologies to reduce freshwater demand, such as recycling their own produced water and hydraulic fracturing fluids. We recently reported that some shale gas operators have begun reusing produced water for hydraulic fracturing of additional wells (see GAO-12-156).

[50]GAO-11-35.

[51]Massachusetts Institute of Technology, *The Future of Natural Gas: An Interdisciplinary MIT Study* (2011) (web.mit.edu/mitei/research/studies/report-natural-gas.pdf).

comparison to other water uses, such as agriculture and other industrial purposes. However, the cumulative effects of using surface water or groundwater at multiple oil and gas development sites can be significant at the local level, particularly in areas experiencing drought conditions.

Similar to shale oil and gas development, development of gas from coalbed methane formations poses a risk of aquifer depletion. To develop natural gas from such formations, water from the coal bed is withdrawn to lower the reservoir pressure and allow the methane to desorb from the coal. According to a 2001 USGS report, dewatering coalbed methane formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation.[52]

The key issue for water quantity is whether the total amount of water consumed for the development of shale oil and gas will result in a significant long-term loss of water resources within a region, according to a 2012 University of Texas study. This is because water used in shale oil and gas development is largely a consumptive use and can be permanently removed from the hydrologic cycle, according to EPA and Interior officials. However, it is difficult to determine the long-term effect on water resources because the scale and location of future shale oil and gas development operations remains largely uncertain. Similarly, the total volume that operators will withdraw from surface water and aquifers for drilling and hydraulic fracturing is not known until operators submit applications to the appropriate regulatory agency. As a result, the cumulative amount of water consumed over the lifetime of the activity—key information needed to assess the effects of water withdrawals—remains largely unknown.

Water Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to water quality from contamination of surface water and groundwater as a result of spills and releases of produced water, chemicals, and drill cuttings; erosion from ground disturbances; or underground migration of gases and chemicals.

[52]USGS, *A Field Conference On Impacts of Coalbed Methane Development in the Powder River Basin, Wyoming,* Open-File Report 01-126 (Denver, CO: 2001).

Spills and Releases

Shale oil and gas development poses a risk to water quality from spills or releases of toxic chemicals and waste that can occur as a result of tank ruptures, blowouts, equipment or impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or operational errors. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In August 2003, we reported that damage from oil and gas related spills on National Wildlife Refuges varied widely in severity, ranging from infrequent small spills with no known effect on wildlife to large spills causing wildlife death and long-term water and soil contamination.[53]

Drill cuttings, if improperly managed, also pose a risk to water quality. Drill cuttings brought to the surface during oil and gas development may contain naturally occurring radioactive materials (NORM),[54] along with other decay elements (radium-226 and radium-228), according to an industry report presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition.[55] According to the report, drill cuttings are stored and transported through steel pipes and tanks—which the radiation cannot penetrate. However, improper transport and handling of drill cuttings could result in water contamination. For example, NORM

[53]GAO, *National Wildlife Refuges: Opportunities to Improve the Management and Oversight of Oil and Gas Activities on Federal Lands*, GAO-03-517 (Washington, D.C.: Aug. 28, 2003).

[54]Naturally occurring radioactive materials (NORM) are present at varying degrees in virtually all environmental media, including rocks and soils. According to a DOE report, human exposure to radiation comes from a variety of sources, including naturally occurring radiation from space, medical sources, consumer products, and industrial sources. Normal disturbances of NORM-bearing rock formations by activities such as drilling do not generally pose a threat to workers, the general public or the environment, according to studies and publications we reviewed.

[55]J. Daniel Arthur, Brian Bohm, David Cornue. "Environmental Considerations of Modern Shale Gas Development" (presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 2009).

concentrations can build up in pipes and tanks, if not properly disposed, and the general public or water could come into contact with them, according to an EPA fact sheet.[56]

The chemical additives in fracturing fluid, if not properly handled, also poses a risk to water quality if they come into contact with surface water or groundwater. Some additives used in fracturing fluid are known to be toxic, but data are limited for other additives. For example, according to reports we reviewed, operators may include diesel fuel—a refinery product that consists of several components, possibly including some toxic impurities such as benzene and other aromatics—as a solvent and dispersant in fracturing fluid. While some additives are known to be toxic, less is known about potential adverse effects on human health in the event that a drinking water aquifer was contaminated as a result of a spill or release of fracturing fluid, according to the 2011 New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement. This is largely because the overall risk of human health effects occurring from hydraulic fracturing fluid would depend on whether human exposure occurs, the specific chemical additives being used, and site-specific information about exposure pathways and environmental contaminant levels.

The produced water and fracturing fluids returned during the flowback process contain a wide range of contaminants and pose a risk to water quality, if not properly managed.[57] Most of the contaminants occur naturally, but some are added through the process of drilling and hydraulic fracturing. In January 2012, we reported that the range of contaminants found in produced water can include,[58] but is not limited to

- salts, which include chlorides, bromides, and sulfides of calcium, magnesium, and sodium;

[56]EPA, *Radioactive Waste from Oil and Gas Drilling*, EPA 402-F-06-038 (Washington, D.C.: April 2006).

[57]A 2009 report from DOE and the Groundwater Protection Council—a nonprofit organization whose members consist of state ground water regulatory agencies—estimates that from 30 percent to 70 percent of the original fluid injected returns to the surface.

[58]GAO-12-156.

- metals, which include barium, manganese, iron, and strontium, among others;
- oil, grease, and dissolved organics, which include benzene and toluene, among others;
- NORM; and
- production chemicals, which may include friction reducers to help with water flow, biocides to prevent growth of microorganisms, and additives to prevent corrosion, among others.

At high levels, exposure to some of the contaminants in produced water could adversely affect human health and the environment. For example, in January 2012, we reported that, according to EPA, a potential human health risk from exposure to high levels of barium is increased blood pressure.[59] From an environmental standpoint, research indicates that elevated levels of salts can inhibit crop growth by hindering a plant's ability to absorb water from the soil. Additionally, exposure to elevated levels of metals and production chemicals, such as biocides, can contribute to increased mortality among livestock and wildlife.

Operators must transport or store produced water prior to disposal. According to a 2012 University of Texas report, produced water temporarily stored in tanks (see fig. 12) or impoundments prior to treatment or disposal may be a source of leaks or spills, if not properly managed. The risk of a leak or spill is particularly a concern for surface impoundments as improper liners can tear, and impoundments can overflow.[60] For example, according to state regulators in North Dakota, in 2010 and 2011, impoundments overflowed during the spring melt season because operators did not move fluids from the impoundments—which

[59] GAO-12-156.

[60] The composition of pit lining depends on regulatory requirements, which vary from state to state.

were to be used for temporary storage—to a proper disposal site before the spring thaw.[61]

Figure 12: Storage Tank for Produced Water in the Barnett Shale

Source: GAO.

Unlike shale oil and gas formations, water permeates coalbed methane formations, and its pressure traps natural gas within the coal. To produce natural gas from coalbed methane formations, water must be extracted to lower the pressure in the formation so the natural gas can flow out of the coal and to the wellbore. In 2000, USGS reported that water extracted from coalbed methane formations is commonly saline and, if not treated

[61]In response, the state passed a new law that will significantly reduce the number of pits. Under the new law, operators can use pits for temporary storage of fluid from the flowback process but must drain and reclaim the pits no more than 72 hours after hydraulic fracturing is complete.

and disposed of properly, could adversely affect streams and threaten fish and aquatic resources.

According to several reports, handling and transporting toxic fluids or contaminants poses a risk of environmental contamination for all industries, not just oil and gas development; however, the large volume of fluids and contaminants—fracturing fluid, drill cuttings, and produced water—that is associated with the development of shale oil and gas poses an increased risk for a release to the environment and the potential for greater effects should a release occur in areas that might not otherwise be exposed to these chemicals.

Erosion

Oil and gas development, whether conventional or shale oil and gas, can contribute to erosion, which could carry sediments and pollutants into surface waters. Shale oil and gas development require operators to undertake a number of earth-disturbing activities, such as clearing, grading, and excavating land to create a pad to support the drilling equipment. If necessary, operators may also construct access roads to transport equipment and other materials to the site. As we reported in February 2005, as with other construction activities, if sufficient erosion controls to contain or divert sediment away from surface water are not established then surfaces are exposed to precipitation and runoff could carry sediment and other harmful pollutants into nearby rivers, lakes, and streams.[62] For example, in 2012, the Pennsylvania Department of Environmental Protection concluded that an operator in the Marcellus Shale did not provide sufficient erosion controls when heavy rainfall in the area caused significant erosion and contamination of a nearby stream from large amounts of sediment.[63] As we reported in February 2005, sediment clouds water, decreases photosynthetic activity, and destroys organisms and their habitat.

[62]GAO, *Storm Water Pollution: Information Needed on the Implications of Permitting Oil and Gas Construction Activities*, GAO-05-240 (Washington, D.C.: Feb. 9, 2005).

[63]In response, the state required the operator to install silt fences, silt socks, gravel surfacing of the access road, and a storm water capture ditch.

Underground Migration

According to a number of studies and publications we reviewed, underground migration of gases and chemicals poses a risk of contamination to water quality.[64] Underground migration can occur as a result of improper casing and cementing of the wellbore as well as the intersection of induced fractures with natural fractures, faults, or improperly plugged dry or abandoned wells. Moreover, there are concerns that induced fractures can grow over time and intersect with drinking water aquifers. Specifically:

Improper casing and cementing. A well that is not properly isolated through proper casing and cementing could allow gas or other fluids to contaminate aquifers as a result of inadequate depth of casing,[65] inadequate cement in the annular space around the surface casing, and ineffective cement that cracks or breaks down under the stress of high pressures. For example, according to a 2008 report by the Ohio Department of Natural Resources, a gas well in Bainbridge, Ohio, was not properly isolated because of faulty sealing, allowing natural gas to build up in the space around the production casing and migrate upward over about 30 days into the local aquifer and infiltrating drinking water wells.[66] The risk of contamination from improper casing and cementing is not unique to the development of shale formations. Casing and cementing practices also apply to conventional oil and gas development. However, wells that are hydraulically fractured have some unique aspects. For example, hydraulically fractured wells are commonly exposed to higher pressures than wells that are not hydraulically fractured. In addition, hydraulically fractured wells are exposed to high pressures over a longer period of time as fracturing is conducted in multiple stages, and wells may be refractured multiple times—primarily to extend the economic life of the well when production declines significantly or falls below the estimated reservoir potential.

[64]Methane can occur naturally in shallow bedrock and unconsolidated sediments and has been known to naturally seep to the surface and contaminate water supplies, including water wells. Methane is a colorless, odorless gas and is generally considered nontoxic, but there could be an explosive hazard if gas is present in significant volumes and the water well is not properly vented.

[65]The depth for casing and cementing may be determined by state regulations.

[66]Ohio Department of Natural Resources, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio* (September 2008).

Natural fractures, faults, and abandoned wells. If shale oil and gas development activities result in connections being established with natural fractures, faults, or improperly plugged dry or abandoned wells, a pathway for gas or contaminants to migrate underground could be created—posing a risk to water quality. These connections could be established through either induced fractures intersecting directly with natural fractures, faults, or improperly plugged dry or abandoned wells or as a result of improper casing and cementing that allow gas or other contaminants to make such connections. In 2011, the New York State Department of Environmental Conservation reported that operators generally avoid development around known faults because natural faults could allow gas to escape, which reduces the optimal recovery of gas and the economic viability of a well. However, data on subsurface conditions in some areas are limited. Several studies we reviewed report that some states are unaware of the location or condition of many old wells. As a result, operators may not be fully aware of the location of abandoned wells and natural fractures or faults.

Fracture growth. A number of such studies and publications we reviewed report that the risk of induced fractures extending out of the target formation into an aquifer—allowing gas or other fluids to contaminate water—may depend, in part, on the depth separating the fractured formation and the aquifer. For example, according to a 2012 Bipartisan Policy Center report, [67] the fracturing process itself is unlikely to directly affect freshwater aquifers because fracturing typically takes place at a depth of 6,000 to 10,000 feet, while drinking water tables are typically less than 1,000 feet deep.[68] Fractures created during the hydraulic fracturing process are generally unable to span the distance between the targeted shale formation and freshwater bearing zones. According to a 2011 industry report, fracture growth is stopped by natural subsurface barriers

[67]Bipartisan Policy Center, *Shale Gas: New Opportunities, New Challenges* (Washington, D.C.: January 2012).

[68]Some coalbed methane formations are much closer to drinking water aquifers than are shale formations. In 2004, EPA reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing in coalbed methane formations. EPA found no confirmed cases linked to the injection of fracturing fluid or subsequent underground movement of fracturing fluids. The report states that, although thousands of coalbed methane formations are fractured annually, EPA did not find confirmed evidence that drinking water wells had been contaminated by the hydraulic fracturing process.

and the loss of hydraulic fracturing fluid.[69] When a fracture grows, it conforms to a general direction set by the stresses in the rock, following what is called fracture direction or orientation. The fractures are most commonly vertical and may extend laterally several hundred feet away from the well, usually growing upward until they intersect with a rock of different structure, texture, or strength. These are referred to as seals or barriers and stop the fracture's upward or downward growth. In addition, as the fracturing fluid contacts the formation or invades natural fractures, part of the fluid is lost to the formation. The loss of fluids will eventually stop fracture growth according to this industry report.

From 2001 through 2010, an industry consulting firm monitored the upper and lower limits of hydraulically induced fractures relative to the position of drinking water aquifers in the Barnett and Eagle Ford Shale, the Marcellus Shale, and the Woodford Shale.[70] In 2011, the firm reported that the results of the monitoring show that even the highest fracture point is several thousand feet below the depth of the deepest drinking water aquifer. For example, for over 200 fractures in the Woodford Shale, the typical distance between the drinking water aquifer and the top of the fracture was 7,500 feet, with the highest fracture recorded at 4,000 feet from the aquifer. In another example, for the 3,000 fractures performed in the Barnett Shale, the typical distance from the drinking water aquifer and the top of the fracture was 4,800 feet, and the fracture with the closest distance to the aquifer was still separated by 2,800 feet of rock. Table 4 shows the relationship between shale formations and the depth of treatable water in five shale gas plays currently being developed.

[69] George E. King, Apache Corporation, "Explaining and Estimating Fracture Risk: Improving Fracture Performance in Unconventional Gas and Oil Wells" (presented at the Society of Petroleum Engineers Hydraulic Fracturing Conference, The Woodlands, Texas, February 2012).

[70] Kevin Fisher, Norm Warpinski, Pinnacle—A Haliburton Service, "Hydraulic Fracture-Height Growth: Real Data" (presented at the Society of Petroleum Engineers Technical Conference and Exhibition, Denver, Colorado, October 2011).

Table 4: Shale Formation and Treatable Water Depth

Distance in feet

Shale play	Depth to shale	Depth to base of treatable water	Distance between shale and base of treatable water
Barnett	6,500- 8,500	1,200	5,300- 7,300
Fayetteville	1,000- 7,000	500	500- 6,500
Haynesville	10,500- 13,500	400	10,100- 13,100
Marcellus	4,000- 8,500	850	2,125- 7,650
Woodford	6,000- 11,000	400	5,600- 10,600

Source: GAO analysis of data presented in a report prepared at the request of the DOE.

Note: Depths to base of treatable water are approximate. According to the report, the depth to base of treatable water was based on data from state oil and gas agencies and state geological survey data.

Several government, academic, and nonprofit organizations evaluated water quality conditions or groundwater contamination incidents in areas experiencing shale oil and gas development. Among the studies and publications we reviewed that discuss the potential contamination of drinking water from the hydraulic fracturing process in shale formations are the following:

- In 2011, the Center for Rural Pennsylvania analyzed water samples taken from 48 private water wells located within about 2,500 feet of a shale gas well in the Marcellus Shale.[71] The analysis compared predrilling samples to postdrilling samples to identify any changes to water quality. The analysis showed that there were no statistically significant increases in pollutants prominent in drilling waste fluids—such as total dissolved solids, chloride, sodium, sulfate, barium, and strontium—and no statistically significant increases in methane. The study concluded that gas well drilling had not had a significant effect on the water quality of nearby drinking water wells.

- In 2011, researchers from Duke University studied shale gas drilling and hydraulic fracturing and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York. Sixty drinking water samples were collected in Pennsylvania and New York from bedrock aquifers that

[71]The Center for Rural Pennsylvania, *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies* (Harrisburg, Pennsylvania: October 2011).

overlie the Marcellus or Utica Shale formations—some from areas with shale gas development and some from areas with no shale gas development.[72] The study found that methane concentrations were detected generally in 51 drinking water wells across the region—regardless of whether shale gas drilling occurred in the area—but that concentrations of methane were substantially higher closer to shale gas wells. However, the researchers reported that a source of the contamination could not be determined. Further, the researchers reported that they found no evidence of fracturing fluid in any of the samples.

- In 2011, the Ground Water Protection Council evaluated state agency groundwater investigation findings in Texas and categorized the determinations regarding causes of groundwater contamination resulting from the oil and gas industry.[73] During the study period—from 1993 through 2008—multistaged hydraulic fracturing stimulations were performed in over 16,000 horizontal shale gas wells. The evaluation of the state investigations found that there were no incidents of groundwater contamination caused by hydraulic fracturing.

In addition, regulatory officials we met with from eight states—Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas—told us that, based on state investigations, the hydraulic fracturing process has not been identified as a cause of groundwater contamination within their states.

A number of studies discuss the potential contamination of water from the hydraulic fracturing process in shale formations. However, according to several studies we reviewed, there are insufficient data for predevelopment (or baseline) conditions for groundwater. Without data to compare predrilling conditions to postdrilling conditions, it is difficult to determine if adverse effects were the result of oil and gas development, natural occurrences, or other activities. In addition, while researchers

[72] Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, "Methane Contamination of Drinking Water Accompanying Gas-well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Science* 108, no. 20 (2011).

[73] Ground Water Protection Council, *State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms: A Two-State Review: Ohio and Texas* (Oklahoma City, Oklahoma: August 2011).

have evaluated fracture growth, the widespread development of shale oil and gas is relatively new. As such, little data exist on (1) fracture growth in shale formations following multistage hydraulic fracturing over an extended time period, (2) the frequency with which refracturing of horizontal wells may occur, (3) the effect of refracturing on fracture growth over time,[74] and (4) the likelihood of adverse effects on drinking water aquifers from a large number of hydraulically fractured wells in close proximity to each other.

Ongoing Studies Related to Water Quality

Ongoing studies by federal agencies, industry groups, and academic institutions are evaluating the effects of hydraulic fracturing on water resources so that, over time, better data and information about these effects should become available to policymakers and the public. For example, EPA's Office of Research and Development initiated a study in January 2010 to examine the potential effects of hydraulic fracturing on drinking water resources. According to agency officials, the agency anticipates issuing a progress report in 2012 and a final report in 2014. EPA is also conducting an investigation to determine the presence of groundwater contamination within a tight sandstone formation being developed for natural gas near Pavillion, Wyoming, and, to the extent possible, identify the source of the contamination. In December 2011, EPA released a draft report outlining findings from the investigation. The report is not finalized, but the agency indicated that it had identified certain constituents in groundwater above the production zone of the Pavillion natural gas wells that are consistent with some of the constituents used in natural gas well operations, including the process of hydraulic fracturing. DOE researchers are also testing the vertical growth of fractures during hydraulic fracturing to determine whether fluids can travel thousands of feet through geologic faults into water aquifers close to the surface.

Land and Wildlife

Oil and gas development, whether conventional or shale oil and gas, poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting waste products underground.

[74]According to research presented in the New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement, refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.

Habitat Degradation

According to studies and publications we reviewed, development of oil and gas, whether conventional or shale oil and gas, poses a risk to habitat from construction activities. Specifically, clearing land of vegetation and leveling the site to allow access to the resource, as well as construction of roads, pipelines, storage tanks, and other infrastructure needed to extract and transport the resource can fragment habitats.[75] In August 2003, we reported that oil and gas infrastructure on federal wildlife refuges can reduce the quality of habitat by fragmenting it.[76] Fragmentation increases disturbances from human activities, provides pathways for predators, and helps spread nonnative plant species.

In addition, spills of oil, gas, or other toxic chemicals have harmed wildlife and habitat. Oil and gas can injure or kill wildlife by destroying the insulating capacity of feathers and fur, depleting oxygen available in water, or exposing wildlife to toxic substances. Long-term effects of oil and gas contamination on wildlife are difficult to determine, but studies suggest that effects of exposure include reduced fertility, kidney and liver damage, immune suppression, and cancer. In August 2003, we reported that even small spills may contaminate soil and sediments if they occur frequently.[77] Further, noise and the presence of new infrastructure associated with shale gas development may also affect wildlife. A study by the Houston Advanced Research Center and the Nature Conservancy investigated the effects of noise associated with gas development on the Attwater's Prairie Chicken—an endangered species. The study explored how surface disruptions, particularly construction of a rig and noise from diesel generators would affect the animal's movement and habitat.[78] The results of the study found that the chickens were not adversely affected by the diesel engine generator's noise but that the presence of the rig caused the animals to temporarily disperse and avoid the area.

[75]Habitat fragmentation occurs when a network of roads and other infrastructure is constructed in previously undeveloped areas.

[76]GAO-03-517.

[77]GAO-03-517.

[78]James F. Bergan, Richard Haut, Jared Judy, and Liz Price. "Living In Harmony—Gas Production and the Attwater's Prairie Chicken" (presented at the Society of Professional Engineers Annual Technical Conference, Florence, Italy, September 2010).

A number of studies we reviewed identified risks to habitat and wildlife as a result of shale oil and gas activities. However, because shale oil and gas development is relatively new in some areas, the long-term effects—after operators are to have restored portions of the land to predevelopment conditions—have not been evaluated. Without these data, the cumulative effects of shale oil and gas development on habitat and wildlife are largely unknown.

Induced Seismicity

According to several studies and publications we reviewed, the hydraulic fracturing process releases energy deep beneath the surface to break rock but the energy released is not large enough to trigger a seismic event that could be felt on the surface. However, a process commonly used by operators to dispose of waste fluids—underground injection—has been associated with earthquakes in some locations. For example, a 2011 Oklahoma Geological Survey study reported that underground injection can induce seismicity. In March 2012, the Ohio Department of Natural Resources reported that “there is a compelling argument” that the injection of produced water into underground injection wells was the cause of the 2011 earthquakes near Youngstown, Ohio. In addition, the National Academy of Sciences released a study in June 2012 that concluded that underground injection of wastes poses some risk for induced seismicity, but that very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

The available research does not identify a direct link between hydraulic fracturing and increased seismicity, but there could be an indirect effect to the extent that increased use of hydraulic fracturing produces increased amounts of water that is disposed of through underground injection. In addition, according to the National Academy of Science’s 2012 report, accurately predicting magnitude or occurrence of seismic events is generally not possible, in part, because of a lack of comprehensive data on the complex natural rock systems at energy development sites.

Extent of Risks Is Unknown and Depends on Many Factors

The extent and severity of environmental and public health risks identified in the studies and publications we reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations in the basin; climatic conditions; business practices; and regulatory and enforcement activities.

Location and rate of development. The location of oil and gas operations and the rate of development can affect the extent and severity of environmental and public health risks. For example, as we reported in October 2010, while much of the natural gas that is vented and flared is considered to be unavoidably lost, certain technologies and practices can be applied throughout the production process to capture some of this gas, according to the oil and gas industry and EPA. The technologies' technical and economic feasibility varies and sometimes depends on the location of operations. For example, some technologies require a substantial amount of electricity, which may be less feasible for remote production sites that are not on the electrical grid. In addition, the extent and severity of environmental risks may vary based on the location of oil and gas wells. For example, in areas with high population density that are already experiencing challenges adhering to federal air quality limits, increases in ozone levels because of emissions from oil and gas development may compound the problem.

Geological characteristics. Geological characteristics can affect the extent and severity of environmental and public health risks associated with shale oil and gas development. For example, geological differences between tight sandstone and shale formations are important because, unlike shale, tight sandstone has enough permeability to transmit groundwater to water wells in the region. In a sense, the tight sandstone formation acts as a reservoir for both natural gas and for groundwater. In contrast, shale formations are typically not permeable enough to transmit water and are not reservoirs for groundwater. According to EPA officials, hydraulic fracturing in a tight sandstone formation that is a reservoir for both natural gas and groundwater poses a greater risk of contamination than the same activity in a deep shale formation.

Climatic conditions. Climatic factors, such as annual rainfall and surface temperatures, can also affect the environmental risks for a specific region or area. For example, according to a 2007 study funded by DOE, average rainfall amounts can be directly related to soil erosion.[79] Specifically,

[79]ALL Consulting and the Interstate Oil and Gas Compact Commission, *Improving Access to Onshore Oil and Gas Resources on Federal Lands* (a special report prepared at the request of the U.S. Department of Energy National Energy and Technology Laboratory, March 2007).

areas with higher precipitation levels may be more susceptible to soil compaction and rutting during the well pad construction phase. In another example, risk of adverse effects from exposures to toxic air contaminants can vary substantially between drilling sites, in part, because of the specific mix of emissions and climatic conditions that affect the transport and dispersion of emissions. Specifically, wind speed and direction, temperature, as well as other climatic conditions, can influence exposure levels of toxic air contaminants. For example, according to a 2012 study from the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, the combination of air emissions from gas operations, snow on the ground, bright sunshine, and temperature inversions during winter months have contributed to ozone creation in Sublette County, Wyoming.[80]

Business practices. A number of studies we reviewed indicate that some adverse effects from shale oil and gas development can be mitigated through the use of technologies and best practices. For example, according to standards and guidelines issued jointly by the Departments of the Interior and Agriculture, mitigation techniques, such as fencing and covers, should be used around impoundments to prevent livestock or wildlife from accessing fluids stored in the impoundments.[81] In another example, EPA's Natural Gas STAR program has identified over 80 technologies and practices that can cost effectively reduce methane emissions, a potent greenhouse gas, during oil and gas development. However, the use of these technologies and business practices are typically voluntary and rely on responsible operators to ensure that necessary actions are taken to prevent environmental contamination. Further, the extent to which operators use these mitigating practices is unknown and could be particularly challenging to identify given the significant increase in recent years in the development of shale oil and gas by a variety of operators, both large and small.

Regulatory and enforcement activities. Potential changes to the federal, state, and local regulatory environment will affect operators' future

[80]Susan Williams, "Discovering Shale Gas: An Investor Guide to Hydraulic Fracturing," Sustainable Investments Institute and Investor Responsibility Research Center Institute (New York, NY: February 2012).

[81]United States Department of the Interior and United States Department of Agriculture. *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*. BLM/WO/ST-06/021+3071/REV 07 (Denver, CO: 2007).

activities and can therefore affect the risks or level of risks associated with shale oil and gas development. Shale oil and gas development is regulated by multiple levels of government—including federal, state, and local. Many of the laws and regulations applicable to shale oil and gas development were put in place before the increase in operations that has occurred in the last few years, and various levels of government are evaluating and, in some cases, revising laws and regulations to respond to the increase in shale oil and gas development. For example, in April 2012, EPA promulgated New Source Performance Standards for the oil and gas industry that, when fully phased-in by 2015, will require emissions reductions at new or modified oil and gas well sites, including wells using hydraulic fracturing. Specifically, these new standards, in part, focus on reducing the venting of natural gas and volatile organic compounds during the flowback process. In addition, areas without prior experience with oil and gas development are just now developing new regulations. These governments' effectiveness in implementing and enforcing this framework will affect future activities and the level of associated risk.

Agency Comments

We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review and comment. We received technical comments from Interior's Assistant Secretary, Policy, Management, and Budget, and from Environmental Protection Agency officials, which we have incorporated as appropriate. In an e-mail received August 27, 2012, the Department of Energy liaison stated the agency had no comments on the report.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of Energy, the Secretary of the Interior, the EPA Administrator, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix IV.

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

List of Requesters

The Honorable Barbara Boxer
Chairman
Committee on Environment and Public Works
United States Senate

The Honorable Sheldon Whitehouse
Chairman
Subcommittee on Oversight
Committee on Environment and Public Works
United States Senate

The Honorable Benjamin L. Cardin
Chairman
Subcommittee on Water and Wildlife
Committee on Environment and Public Works
United States Senate

The Honorable Henry A. Waxman
Ranking Member
Committee on Energy and Commerce
House of Representatives

The Honorable Edward J. Markey
Ranking Member
Committee on Natural Resources
House of Representatives

The Honorable Diana DeGette
Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

The Honorable Robert P. Casey, Jr.
United States Senate

Appendix I: Scope and Methodology

Our objectives for this review were to determine what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.

To determine what is known about the size of shale oil and gas resources, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the Energy Information Administration (EIA), the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academic and industry officials. We interviewed key officials about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators. In addition to the estimates provided by these three organizations, we also obtained and presented technically recoverable shale oil and gas estimates from two private organizations—IHS Inc., and ICF International—and one national advisory committee representing the views of the oil and gas industry and other stakeholders—the National Petroleum Council. For all estimates we report, we conducted a review of the methodologies used in these estimates for fatal flaws; we did not find any fatal flaws in these methodologies.

To determine what is known about the amount of produced shale oil and gas from 2007 through 2011, we obtained data from EIA—the federal agency responsible for estimating and reporting this and other energy information. EIA officials provided us with estimated oil and gas production data, including data estimating shale oil and gas estimates from states and two private firms—HPDI, LLC and Lippman Consulting, Inc. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection and validation efforts. We also interviewed officials from three state agencies, representatives from five private companies, and researchers from three academic institutions who are familiar with these data and EIA's methodology and discussed the sources and reliability of the data. We determined that these data were sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas[1], we identified and reviewed more than 90 studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. The studies and publications we reviewed included scientific and industry periodicals, government-sponsored research, reports or other publications from nongovernmental organizations, and presentation materials. We identified these studies by conducting a literature search and by asking for recommendations during our interviews with stakeholders. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified potential risks for shale oil and gas development. However, given our methodology, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern. The widespread use of horizontal drilling and hydraulic fracturing to develop shale oil and gas is relatively new. Studying the effects of an activity and completing a formal peer-review process can take numerous months or years. Because of the relative short time frame for operations and the lengthy time frame for studying effects, we did not limit the review to peer-reviewed publications.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas drilling operations may be constructed. Second, operators' use of effective best practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few that are based on evaluating predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse changes to shale oil and gas development. In addition, changes to the federal, state, and local

[1]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale. Specifically, coalbed and tight sand formations may rely on these practices, and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on the development of shale formations.

regulatory environment and the effectiveness in implementation and enforcement will affect operators' future activities. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices, which in turn, may vary across oil and gas companies making it difficult to distinguish between risks that are inherent to the development of shale oil and gas from risks that are specific to particular business practices.

To obtain additional perspectives on issues related to environmental and public health risks, we interviewed a nonprobability sample of stakeholders representing numerous agencies and organizations. (See app. II for a list of agencies and organizations contacted.) We selected these agencies and organizations to be broadly representative of differing perspectives regarding environmental and public health risks. In particular, we obtained views and information from federal officials from the Department of Energy's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management and Bureau of Indian Affairs, and the Environmental Protection Agency; state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas; tribal officials from the Osage Nation; shale oil and gas operators; representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. The findings from our interviews with stakeholders and officials cannot be generalized to those we did not speak with.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: List of Agencies and Organizations Contacted

Federal Agencies	Congressional Research Service Department of Energy's National Energy Technology Laboratory Department of Health and Human Services Department of the Interior's Bureau of Indian Affairs Department of the Interior's Bureau of Land Management Department of the Interior's U.S. Geological Survey Environmental Protection Agency
State Agencies	Arkansas Department of Environmental Quality Arkansas Oil and Gas Commission Colorado Oil and Gas Conservation Commission Louisiana Department of Natural Resources North Dakota Industrial Commission Ohio Department of Natural Resources Ohio Environmental Protection Agency Oklahoma Geological Survey Oklahoma Corporation Commission Texas Railroad Commission
Academic Institutions	Colorado School of Mines Oklahoma University Stanford University University of Texas at Arlington University of Texas Energy Center and Bureau of Economic Geology
Environmental Organizations	Clean Water Action Pennsylvania Earthworks Oil and Gas Accountability Project Environmental Defense Fund Subra Consulting Western Resource Advocates
Public Health Organizations	The Endocrine Disruption Exchange National Association of County and City Health Officials Southwest Pennsylvania Environmental Health Project
Industry	ALL Consulting American Exploration and Production Council American Petroleum Institute Apache Corporation

Chesapeake Energy
Colorado Oil and Gas Association
Devon Energy
Powell Shale Digest

Others

Ground Water Protection Council
Martin Consulting
Red River Watershed Management Institute
Osage Tribal Nation

Appendix III: Additional Information on USGS Estimates

The USGS estimates potential oil and gas resources in about 60 geological areas (called “provinces”) in the United States. Since 1995, USGS has conducted oil and gas estimates at least once in all of these provinces; about half of these estimates have been updated since the year 2000 (see table 5). USGS estimates for an area are updated once every 5 years or more, depending on factors such as the importance of an area.

Table 5: USGS Estimates

Name of USGS province	Most recent assessment year
Northern Alaska	2006
Central Alaska	2004
Southern Alaska	2011
Western Oregon-Wash.	2009
Eastern Oregon-Wash.	2006
Northern Coastal	1995
Sonoma-Livermore	1995
Sacramento Basin	2006
San Joaquin Basin	2004
Central Coastal	1995
Santa Maria Basin	1995
Ventura Basin	1995
Los Angeles Basin	1995
Idaho-Snake River Downwarp	1995
Western Great Basin	1995
Eastern Great Basin	2004
Uinta-Piceance Basin	2002
Paradox Basin	1995
San Juan Basin	2002
Albuquerque-Sante Fe Rift	1995
Northern Arizona	1995
S. Ariz.-S.W. New Mexico	1995
South-Central New Mexico	1995
Montana Thrust Belt	2002
Central Montana	2001
Southwest Montana	1995
Hanna, Laramie, Shirley	2005

Name of USGS province	Most recent assessment year
Williston Basin (includes Bakken Shale Formation)	2008
Powder River Basin	2006
Big Horn Basin	2008
Wind River Basin	2005
Wyoming Thrust Belt	2004
Southwestern Wyoming	2002
Park Basins	1995
Denver Basin	2003
Las Animas Arch	1995
Raton Basin-Sierra Grande Uplift	2005
Palo Duro Basin	1995
Permian Basin (includes Barnett Shale)	2007
Bend Arch-Ft. Worth Basin	2004
Marathon Thrust Belt	1995
Western Gulf Coast (includes Eagle Ford Shale)	2011
East Texas Basin Province	2011
Louisiana-Mississippi Salt Basins Province	2011
Florida Peninsula	2000
Superior	1995
Cambridge Arch-Central Kansas	1995
Nemaha Uplift	1995
Forest City Basin	1995
Anadarko Basin	2011
Sedgwick Basin/Salina Basin	1995
Cherokee Platform	1995
Southern Oklahoma	1995
Arkoma Basin	2010
Michigan Basin	2005
Illinois Basin	2007
Black Warrior Basin	2002
Cincinnati Arch	1995
Appalachian Basin (includes Marcellus Shale)	2011
Blue Ridge Thrust Belt	1995
Piedmont	1995

Source: USGS.

Appendix IV: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the contact named above, Christine Kehr, Assistant Director; Lee Carroll; Nirmal Chaudhary; Cindy Gilbert; Alison O'Neill; Marietta Revesz, Dan C. Royer; Jay Spaan; Kiki Theodoropoulos; and Barbara Timmerman made key contributions to this report.

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