UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

October 29, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Jordan Cove Energy Project LP and the Pacific Connector Gas Pipeline Notice of Intent to Prepare an Environmental Impact Statement. EPA Region 10 Project Number: 12-0042-FRC and 12-0049-AFS. *FERC Docket Nos. PF12-7-000 and PF12-17-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA) would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) August 13, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline. With these comments we are also responding to the September 21, 2012 NOI to prepare an EIS issued by the Forest Service and BLM for Right of Way grants and land use amendments related to the Pacific Connector Gas Pipeline. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

The FERC's NOI describes Jordan Cove's proposal to construct and operate an LNG export terminal on the North Spit of Coos Bay. The terminal would have the capacity to produce approximately six million metric tons per annum of LNG (equivalent to 0.9 billion cubic feet per day [Bcf/d] of natural gas). Facilities would include:

- 7.3 mile long waterway in Coos Bay for about 80 LNG carriers per year;
- 0.3 mile long access channel and marine berth;
- A cryogenic transfer pipeline;
- Two 160,000 cubic meter LNG storage tanks;
- Four liquefaction trains (each with a capacity of 1.5 million metric tons per annum);
- Two feed gas and dehydration trains with a combined throughput of 1Bcf/d of natural gas; and
- A 350 megawatt South Dunes power plant.

The attendant Pacific Connector pipeline would be 36 inches in diameter and about 230 miles long, extending from interconnections with other interstate pipelines near Malin, Oregon to the Jordan Cove LNG terminal at Coos Bay. The pipeline would have a design capacity of 0.9 Bcf/d of natural gas. Related facilities include:

- Two meter stations at the interconnections with the existing Gas Transmission Northwest and Ruby pipelines near Malin, Oregon;
- A 23,000 horsepower compressor station adjacent to the GTN and Ruby meter stations;
- A meter station at the interconnection with the existing Williams Northwest Pipeline system near Myrtle Creek, Oregon; and
- A meter station at the Jordan Cove terminal.

The enclosed scoping comments were prepared based on our review of the NOIs referenced above and the draft Resource Reports 1 and 10. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS. Among these issues is the range of alternatives. We encourage the FERC to consider a broad range of reasonable alternatives in the EIS that are capable of meeting the project's purpose and need and we look forward to continued discussions on this matter. For example, we would be interested in discussing whether an intertie with the Williams pipeline could be considered as a reasonable alternative and examined in the EIS. We also recommend expanding the scope of analysis to capture the non-jurisdictional South Dunes power plant as well as indirect effects related to gas drilling and combustion.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline
FERC Docket Nos. PF12-7-000 and PF12-17-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describe how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

We appreciate that Resource Report 10 for the Pacific Connector Pipeline Project (Section 10.4) evaluates system alternatives for the pipeline route. In the EIS we would like to see a more rigorous exploration of those alternatives. The basis for conclusions reached in Section 10.4.4 is not clear. Specifically, it is not clear how it was determined that an intertie with the Williams pipeline would result in prohibitive costs, associated rates, and environmental impacts. Because such a route would be significantly shorter than the currently proposed route, we recommend that the EIS give this route alternative additional consideration.

Non-Jurisdictional Facilities
In Section 1.9.2 of Resource Report 1, it is determined that as a non-jurisdictional facility, the South Dunes Power Plant does not need to be included in the DEIS. This assertion is based on the Report's interpretation of FERC's NEPA regulations at 18 CFR § 380.12(c)(2)(ii). Per those regulations, four factors are applied to determine the need for FERC to do an environmental review of project-related non-jurisdictional facilities. These factors include:

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

1. Whether or not the regulated activity comprises "merely a link" in a corridor type project (such as a transportation or utility transmission project);
2. Whether there are aspects of the non-jurisdictional facility in the immediate vicinity of the regulated activity which affect the location and configuration of the regulated activity;
3. The extent to which the entire project will be within the FERC's jurisdiction; and
4. The extent of cumulative federal control and responsibility.

Resource Report 1 considers each of these factors and finds that FERC environmental review is not warranted. We believe the Resource Report's interpretation of these criteria to be overly narrow. In particular, because the South Dunes Power Plant and the Jordan Cove Export Facility are interdependent and interconnected, we believe the power plant inherently affects the location of the export facility. Without the power supplied by the power plant, the export facility cannot be built; and without the export facility, there is no need for the power plant to be built.

In addition, CEQ NEPA regulations at 40 CFR 1508.25(a)(1) address connected actions, and clearly call for actions to be considered within the scope of an EIS if they "cannot or will not proceed unless other actions are taken previously or simultaneously" or " are interdependent parts of a larger action and depend on the larger action for their justification"[3]. It is clear from Resource Report 1 that the Power Plant is being constructed for the purpose of supporting the Project. The Power Plant is not being constructed for a purpose independent from the Project. On the contrary, it is being constructed specifically to support the power needs of the Project.

Section 40 C.F.R. 1508.25(a)(3) states that two actions should be evaluated in a single EIS when they are "similar actions, which when viewed with other reasonably foreseeable or proposed agency actions have similarities that provide a basis for evaluating their environmental consequences together, such as common timing and geography." The Power Plant will be built in a timeframe that will coincide with the Project's power needs. The Power Plant is specifically sited in proximity to the Project so that it can operate in conjunction with the Project. Because the South Dunes Power Plan and the Jordan Cove Export Facility are interdependent and interconnected, the locations of the two were selected to enhance the effectiveness of their co-operation. Therefore, we recommend that the FERC include the South Dunes Power Plant within the scope of the EIS.

Environmental Consequences

According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

[3] 40 CFR 1508.25(a)(1)(ii) and (iii)

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water
Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection
Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS

identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats

In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing
As noted in Section 1.6.4 of Resource Report 1, the PCGP Project would affect 383 waterbodies. We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed since the FEIS for the Jordan Cove LNG Export Facility was finalized. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Maintenance Dredging
Resource Report 1 (Section 1.1.2.2) states that maintenance dredging requirements have been revised based on new modeling. The new estimate is that approximately 37,700 cubic yards would need to be dredged for maintenance at year 1. At year 10 that volume would be expected to decrease to 34,600 cubic yards. This is a substantial reduction from estimates of maintenance dredging included in the FEIS for the Jordan Cove Import Facility. We continue to request the inclusion of an analysis supporting the assertion that the capacity of the EPA's Ocean Disposal Site F would be unaffected by the addition of maintenance dredging material over the next 20 years in the EIS. In order for the EPA to concur with the issuance of a Section 103 permit, this will need to be clearly demonstrated.

In addition, we encourage the development of a Maintenance Dredging Plan in consultation with the U.S. Army Corps of Engineers and the EPA. That plan, including disposal, should be consistent with the site management and monitoring plan and reviewed and approved as part of the Section 103 permit process.

Air Quality
The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions
Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state

measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species

The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste

The EPA recommends EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

Seismic and Other Risks

Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population

densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities
During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act
Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities
In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations, low-income populations, and Native American tribes.[4] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [5]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards

[4] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.
[5] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

Socioeconomic Impacts
Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Individual and Family Changes
- Community Resources

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use on the bay and travel over the bar.

Greenhouse Gas (GHG) Emissions
On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[6].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs), and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives

[6]See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change

Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments

Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts

Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "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." The 2012 report from the Energy Information Administration[7] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report goes on to say that about three-quarters of that increase production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

[7] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

Cumulative Impacts
The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources (including plover habitat), air quality, and commercial and recreational use of the bay. We believe the EIS should consider the Oregon Gateway Marine Terminal Complex as described by the Port of Coos Bay (http://www.portofcoosbay.com/orgate.htm) as reasonably foreseeable for the purposes of cumulative effects analysis. We recognize that uncertainty about future development of the North Spit remains, but we believe the stated aspirations of the Port and the Oregon Department of State Lands' 2011 issuance of a removal-fill permit for the development of an access channel and multi-purpose vessel slip provide sufficient reason for including the marine terminal complex in the effects analysis.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, and should evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[8] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[9] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[10].

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

---

[8] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[9] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[10] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

20121121-0008 FERC PDF (Unofficial) 11/21/2012

ORIGINAL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

November 15, 2012

FILED
SECRETARY OF THE
COMMISSION
2012 NOV 21 A 9: 27
FEDERAL ENERGY
REGULATORY COMMISSION

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

RE: EPA Region 3 Scoping Comments in Response to FERC's Notice of Intent to Prepare an Environmental Assessment (EA) for the Planned Cove Point Liquefaction Project; FERC Docket No. PF12-16-000

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA), Region III Office, has conducted a review of the above Notice in conjunction with our responsibilities under the National Environmental Policy Act (NEPA), the Clean Water Act (CWA) and Section 309 of the Clean Air Act. As part of the FERC pre-filing process of soliciting public and agency comments for development of the EA, EPA offers the following scoping comments.

The NOI describes Dominion's proposal to add an LNG export terminal to its existing LNG import terminal on the Chesapeake Bay in Lusby, Maryland. The new terminal would have capacity to process and export up to 750 million standard cubic feet of natural gas per day (0.75 billion cubic feet/day). Facilities would include:

- Natural gas fired turbines to drive the main refrigerant compressors;
- One or two LNG drive trains and new processing facilities;
- 29,000 to 34,000 additional horsepower compression at its existing Loudon County, VA
- Compressor Station and/or its existing Pleasant Valley (Fairfax County, VA) Compressor Station;
- Additional on-site power generation
- Minor modifications to the existing off-shore pier;
- Use of nearby properties and possible relocation of administrative functions

The Project would not include new LNG storage tanks or an increase in the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. The NEPA document should include a clear and robust justification of the underlying purpose and need for the proposed project. In order for the project to move forward, FERC would need

to issue a certificate of "public convenience and necessity". We recommend discussing the proposal in the context of the broader energy market, including existing and proposed LNG export capacity, describing the factors involved in determining public convenience and necessity for this facility.

EPA recommends assessing the cumulative environmental effects resulting from implementation of the proposed project, when combined with other past, present and reasonably foreseeable future actions, regardless of whether these actions are energy related or not, or whether or not FERC has jurisdiction over them. We recommend focusing on resources or communities of concern, or resources "at risk" which could be cumulatively impacted by all of the above actions. Please refer to the Council on Environmental Quality (CEQ) guidance on "Considering Cumulative Effects Under the National Environmental Policy Act", and EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents" for further assistance in identifying appropriate spatial and temporal boundaries for this analysis.

We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. A 2012 report (http://www.eia.gov/analysis/requests/fe/) from the Energy Information Administration (EIA) states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also indicated that about three-quarters of that increase production would be from shale resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic natural gas prices. As part of this assessment, please discuss the extent to which implementation of the proposed project would create a demand for construction of new gas pipelines or expansion of existing pipelines, in order to accommodate the increased volumes of gas supplied to the Cove Point and other facilities.

In the air impact analysis for the Cove Point Project, we recommend considering the direct, temporary emissions from construction of all facilities, as well as permanent air emission impacts from facility operations, including all compressor stations and any vessel traffic related to LNG exports. Additionally, indirect and reasonably foreseeable cumulative impacts from past, present and future actions, when added to the incremental impacts of the Project proposed should be evaluated. These other actions should include FERC jurisdictional facilities and energy generating and transporting-related facilities, as well as actions or facilities which might have air emissions which could impact the same air receptors as the Project, including downstream combustion.

Please note whether construction or operation of the Project would involve any discharges to Waters of the United States, and whether it would affect the Chesapeake Bay Total Maximum Daily Load (TMDL) or any related Watershed Implementation Plans (WIPs).

Printed on 100% recycled/recyclable paper with 100% post-consumer fiber and process chlorine free.
Customer Service Hotline: 1-800-438-2474

20121121-0008 FERC PDF (Unofficial) 11/21/2012

As part of any environmental documentation, please include evaluation of the Project's direct and indirect impacts on the nearby Chesapeake Bay fisheries and fishermen (both recreational and commercial). Will any additional dredging of waterways be required to accommodate the vessels exporting LNG? What biosecurity controls and protocols will be instituted to prevent introduction of invasive species due to ballast water releases? Please include a discussion of how the Project will comply with the Magnuson-Stevens Fishery Conservation and Management Act, as amended by the Sustainable Fisheries Act of 1966 (PL 04-267)(Essential Fish Habitat).

Please express the volume of natural gas proposed to be exported in terms that the average reader can more easily understand. For example, in addition to indicating that the Project would be capable of processing an average of 750 million standard cubic feet of natural gas per day, also express that figure as an equivalent number of average homes this amount of gas could heat, or how many tankers, and of what size, this amount of gas would fill. Also, please calculate how many production wells, on average, would need to be drilled in order to produce this amount of gas.

The NOI states that the Project would not increase the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. Please discuss in the NEPA document whether this would be accomplished by reducing the volume of LNG imports to match the volume of proposed exports, or by employing some other approach.

Please indicate the number, location, size and capacity of the network of bidirectional pipelines from which the proposed Project would or could receive natural gas, and also indicate whether any of those pipelines would need to be expanded or modified in order to provide the volumes of gas anticipated.

Please indicate whether any aspect of the Project would trigger any requirements for hazardous waste management under the Resource Conservation and Recovery Act (RCRA) or other Federal statutes involving management of such waste.

The proposed Dominion Cove Point facility represents one of sixteen (16) applications currently pending before the U.S. Department of Energy (DOE) for approval to export LNG to countries which do not have Free Trade Agreements (FTA) with the United States. At this time, it appears that only one facility has been initially granted full approval (Sabine Pass in Cameron Parish, Louisiana). Although we are aware of the DOE national study in progress on the cumulative *economic* impacts of allowing natural gas exports, EPA believes that the Cove Point NEPA process represents an opportunity for FERC and DOE to jointly and thoroughly consider the indirect and cumulative *environmental* impacts of exporting LNG from Cove Point. The environmental study of the Cove Point Project should be a comprehensive and robust evaluation of potential impacts, which may require a higher level analysis particularly in consideration of the potential for significant cumulative impacts and the level of community interest.

Printed on 100% recycled/recyclable paper with 100% post-consumer fiber and process chlorine free.
Customer Service Hotline: 1-800-438-2474

20121121-0008 FERC PDF (Unofficial) 11/21/2012

Thank you for the opportunity to comment on this Notice. EPA welcomes the opportunity to discuss these topics by phone or in-person, at your convenience. If you have any questions concerning these comments, please contact Mr. Thomas Slenkamp of this Office at (215) 814-2750.

Sincerely,

Jeffrey D. Lapp, Associate Director
Office of Environmental Programs

Printed on 100% recycled/recyclable paper with 100% post-consumer fiber and process chlorine free.
Customer Service Hotline: 1-800-438-2474

Document Content(s)

13114330.tif.....1-4

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

December 26, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Oregon LNG Export Project and Washington Expansion Project. EPA Region 10 Project Number: 12-0055-FRC. *FERC Docket Nos. PF12-18-000 and PF12-20-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) September 24, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Oregon Liquefied Natural Gas (LNG) Export Project and Washington Expansion. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

As described in the NOI, the Oregon LNG export project would consist of components new to and modified from the originally proposed import-only LNG terminal and pipeline (Docket Nos. CP09-6-000 and CP09-7-000) to allow Oregon LNG to export LNG. The export project would be capable of liquefying approximately 1.3 billion cubic feet per day (Bcf/d) of pretreated natural gas for the export of approximately 9 million metric tons per annum (MTPA) of LNG via LNG carriers.

Specifically, the Export Project would be comprised of liquefaction and export facilities at Warrenton, Oregon and approximately 39 miles of new pipeline. Liquefaction facilities would include:

- A natural gas pretreatment facility to remove sulfur compounds, water, mercury, and other impurities;
- Two liquefaction process trains, each capable of a liquefaction capacity of approximately 4.5 MTPA;
- Refrigerant storage;
- New flare system;

- New water intake on the Columbia River and water delivery pipeline from the intake to a new water treatment system.

Pipeline facilities would include:

- 39 miles of new pipeline commencing at milepost (MP) 47.5 of the pending proposed Oregon Pipeline; and
- A new compressor station at MP 80.8.

The connected Washington Expansion Project (WEP) would expand the capacity of Northwest Pipeline GP (Northwest) between Sumas and Woodland, Washington, by 750,000 dekatherms per day to provide natural gas to the proposed Oregon LNG terminal, and to markets in the state of Washington.

Pipeline facilities for the WEP would include:

- Approximately 140 miles of 36-inch-diameter pipeline loop along Northwest's existing Northwest Pipeline in 10 segments; and
- An additional 96,000 horsepower (hp) of compression at five existing compressor stations.

The enclosed scoping comments were prepared based on our review of the NOI referenced above and the draft Resource Report 1. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Oregon LNG Export Project and Washington Expansion Project
FERC Docket Nos. PF12-18-000 and PF12-20-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describing how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

Environmental Consequences
According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water

Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection

Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats
In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing
We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed more recently. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River

Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Dredging

According to Resource Report 1, Oregon LNG expects that construction of the berth and turning basin will require an estimated 1,275,000 cubic yards of dredge material requiring removal. (Section 1.3.1). Oregon LNG has been actively working with agencies and stakeholders to identify an appropriate location for dredge material disposal. We understand that Oregon LNG priority sites have shifted to the USEPA Deepwater Site, the USEPA Shallow Water Site, the US Army Corps of Engineers (USACE) North Jetty S, and the USACE South Jetty Nearshore Site. We provide the following comments for FERC's consideration as Resource Report 10 and the DEIS are developed:

- Capacity at the USEPA Deep Water Site has been characterized by the proponent as "unlimited"[3]. The EPA agrees that capacity at the site is large, but it is not unlimited. The EPA has asked USACE to conduct an assessment of long term capacity as part of the Annual Use Plan for 2014.
- The USEPA Shallow Water Site is used to capacity every season, and accretion limits are very low. Because shoaling is an unacceptable outcome, disposals at this site would need to be monitored with USACE and the EPA.
- The South Jetty Nearshore Site (Oregon) was accepted by the Lower Columbia Solutions Group (LCSG) on a provisional basis in 2011. Future use of this site would need to be coordinated with the LCSG as well as the USACE. The crab fishing community has requested demonstrable proof over multiple seasons that crabs will not be affected by dredge material disposal activity.

The EPA supports and appreciates the long standing efforts of the proponents and FERC to identify alternative disposal site locations. We will continue to work with the proponent and FERC to identify disposal locations that meet established criteria under Section 103 of the Marine Protection, Research and Sanctuaries Act (MPRSA).

Air Quality

The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions

Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most

[3] Attachment 10-1 Table of Dredge Material Disposal Sites

common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-

of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species

The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste

The EPA recommends the EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

As an example, page 1-9 of Draft Resource Report 1 indicates that as a part of the gas conditioning process, sweetened gas will pass through multiple, consumable parallel carbon beds for the removal of any mercury in the gas. Because the carbon beds cannot be regenerated, it will be necessary to replace them after a design life of several years. We recommend the EIS address the expected mercury content of the expended carbon beds, and address disposal requirements consistent with 40 CFR 268.40.

We also note that the proposed pipeline route between MP 3 and MP 4 passes just upstream of the Astoria Marine Construction Company Site. This site and adjacent river sediments are contaminated

with tributyltin and heavy metals from ship refurbishment operations from 1926 to present[4]. The Oregon Department of Environmental Quality (DEQ) will oversee the investigation and cleanup of contaminated soil, groundwater and sediments at the site under an agreement signed with the EPA. We recommend that FERC and the proponents collaborate closely with Oregon DEQ as the pipeline route is analyzed. Should additional construction BMPs be required at this location, those measures should be included in the EIS.

Seismic and Other Risks

Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities

During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act

Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities

In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations,

[4] http://www.deq.state.or.us/lq/cu/nwr/AstoriaMarine/AstoriaMarineConstructionCo.pdf

low-income populations, and Native American tribes.[5] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [6]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group.
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards.

Socioeconomic Impacts

Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Community Resources.

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use within the project area and travel over the bar.

Greenhouse Gas (GHG) Emissions

On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[7].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs),

---

[5] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.

[6] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

[7] See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives
We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change
Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments
Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts
Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "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." The 2012 report from the Energy Information Administration[8] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also notes that about three-quarters of that increased production would be from shale resources. We recommend that FERC consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

Cumulative Impacts
The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources, air quality, and commercial and recreational use of the Columbia River within the projects area of influence.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[9] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[10] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[11].

---

[8] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[9] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[10] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[11] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

From:	Darby, Joan
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Thursday, January 24, 2013 3:20:42 PM
Attachments:	2013-01-24 Jordan Cove Energy Project LP Comments on LNG Export Study.pdf

Please find attached the comments of Jordan Cove Energy Project, L.P. on the LNG Export Study.

Joan M. Darby
Counsel
Dickstein Shapiro LLP
1825 Eye Street NW | Washington, DC 20006
Tel (202) 420-2745| Fax (202) 379-9232
darbyj@dicksteinshapiro.com

Confidentiality Statement
This email message, including any attachments, is intended solely for the use of the addressee(s) named above. This communication may contain privileged and/or confidential material. If you are not the intended recipient, you have received this communication in error, and any review, use, printing, copying, or other dissemination of this email message is strictly prohibited. If you are not the intended recipient, please notify the sender immediately by reply email message or notify our email administrator at postmaster@dicksteinshapiro.com and permanently delete and destroy the original message and any and all copies, including printouts and electronic copies on any computer system.

Dickstein Shapiro LLP
www.DicksteinShapiro.com

DICKSTEINSHAPIROLLP

1825 Eye Street NW | Washington, DC 20006-5403
TEL (202) 420-2200 | FAX (202) 420-2201 | dicksteinshapiro.com

January 24, 2013

By Email
LNGStudy@hq.doe.gov

Mr. John Anderson
U.S. Department of Energy (FE-34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
Forrestal Building, Room 3E-042
1000 Independence Avenue SW
Washington, D.C. 20585

john.anderson@hq.doe.gov

Mr. Edward Myers
U.S. Department of Energy
Office of the Assistant General Counsel
for Electricity and Fossil Energy
Forrestal Building, Room 6B-256
1000 Independence Avenue SW
Washington, D.C. 20585

edward.myers@hq.doe.gov

Re: 2012 LNG Export Study
and
Jordan Cove Energy Project, L.P., FE Docket No. 12-32-LNG

Dear Mr. Anderson and Mr. Myers:

The U.S. Department of Energy (DOE) issued a "Notice of availability of 2012 LNG Export Study and request for comments" (Notice) that was published in the Federal Register on December 11, 2012 (77 Fed. Reg. 73627). The Notice invited "comments regarding the LNG Export Study that will help to inform DOE in its public interest determinations of the authorizations sought in the 15 pending applications" (77 Fed. Reg. at 73629), one of which is the Application of Jordan Cove Energy Project, L.P. (Jordan Cove) pending in the above-referenced docket. In response to DOE's invitation, Jordan Cove submits the following: (1) the overall evaluation of the LNG Export Study by Navigant Consulting, Inc. (Navigant), which is set forth in the January 22, 2012 letter from Navigant to Jordan Cove attached to this letter as an appendix; and (2) comments pertinent to the LNG Export Study as it applies specifically to Jordan Cove's Application, which are also based on an analysis by Navigant and which are set forth immediately below.

Both reports comprising the LNG Export Study – the January 2012 Energy Information Administration analysis focuses on impacts on domestic energy markets and the December 2012 NERA Economic Consulting analysis focused on impacts on the U.S. economy – are devoid of regional assessments. Because the LNG Export Study analyzes LNG exports only from the U.S. Gulf Coast, it tends to overestimate price impacts of exporting LNG and it fails to identify, and consequently overlooks, economic contributions that would be made by LNG exports from an export project like Jordan Cove situated on the U.S. West Coast.

Jordan Cove will export LNG sourced from more abundant and less costly regional gas supplies that are not accessible to Gulf Coast projects, namely resources from Western Canada and the U.S. Rockies. The lower average delivered supply cost of the natural gas supplies available to Jordan Cove means that, had LNG exports from Jordan Cove's West Coast terminal been included in the LNG Export Study, the forecasted price impacts would likely have been mitigated. Stated differently, the underlying assumption of only Gulf-sourced LNG exports likely resulted in price impacts being overestimated in the LNG Export Study

As a U.S. West Coast terminal, Jordan Cove will also have the advantage of shorter distances and less sailing time (without a Panama Canal transit) to the high-demand Asian markets for LNG and consequently the advantage of significantly lower shipping costs. Indeed, the NERA analysis estimated shipping costs to those markets from Canadian West Coast LNG terminals at $1.23/MMBtu, which is $1.31 less than (and less than half of) its estimate of $2.54/MMBtu for shipping costs to Asia from the U.S. Gulf Coast. The NERA analysis found that Canadian exports to Asia would nevertheless have an overall higher cost due to liquefaction capital costs. NERA estimated the loaded liquefaction cost element for Canadian projects at $3.88/MMBtu and for U.S. Gulf Coast projects at $2.14/MMBtu. While U.S. West Coast "greenfield" projects would have higher capital costs than U.S. Gulf Coast "brownfield" projects, their costs would not approach those of projects located in remote and rugged Kitimat, British Columbia. Assuming that Jordan Cove's loaded liquefaction cost element would be mid-way between the Canadian and U.S. Gulf Coast figures estimated by NERA, it would be $3.01/MMBtu or $0.87 more than the Gulf Coast figure. Jordan Cove's shipping cost advantage of $1.31/MMBtu more than makes up for its higher liquefaction costs, leaving Jordan Cove with an overall cost advantage of $0.44/MMBtu over U.S. Gulf Coast projects. Jordan Cove's cost advantage not only means that Asian buyers would benefit from a lower delivered cost of LNG, but also that the U.S. would reap greater economic benefits.

Because the LNG Export Study does not account for U.S. West Coast projects being able to export LNG at a lower overall delivered cost, it underestimates economic benefits in at least two ways. Since NERA's modeling is based only on Gulf-sourced LNG exports that would have higher delivered costs, it potentially understates the equilibrium export volumes, and therefore the associated economic benefits. In addition to such a volume-driven increase in economic benefits, the inclusion of U.S. West Coast projects like Jordan Cove in the LNG Export Study would have produced an increase in economic benefits due to the composition of the delivered cost of LNG. Simply stated, the relative portion of the price paid for a U.S. LNG export flowing to the U.S. terminal, as opposed to the portion flowing to the non-U.S. shipping company, would be greater if the export is from the U.S. West Coast instead of from the U.S. Gulf Coast. Thus, the substitution of Jordan Cove's higher liquefaction capital costs (which lead to economic benefits) for a U.S. Gulf Coast project's higher shipping costs (which do not lead to economic benefits) results in more economic benefits being kept in the U.S.

In sum, DOE should, as the LNG Export Study does not, recognize the economic contributions that would be unique to LNG exports from an export project like Jordan Cove situated on the U.S. West Coast as compared to projects on the other U.S. coasts. Most importantly, DOE should not put Jordan Cove at any disadvantage as it competes in the market, not only with U.S.

projects but also with proposed Canadian projects, to determine which export projects will be constructed and become operational. LNG exports from Canada (which would displace LNG exports from the U.S.) would have the same impacts on North American natural gas prices as LNG exports from the U.S., but the economic benefits of those exports would accrue to Canada and be lost to the United States. On the other hand, exports of Canadian gas via Jordan Cove will have the most limited impacts on U.S. prices of any proposed export terminal and, in constructing and operating its terminal, Jordan Cove will make a tremendous investment in a currently economically depressed region of the country, with the attendant employment and economic benefits accruing to the United States.

Thank you for your consideration of Jordan Cove's comments.

Sincerely,

/s/ Beth L. Webb

Beth L. Webb
Joan M. Darby

Attorneys for
Jordan Cove Energy Project, L.P.

cc: DOE/FE, Marc Talbert, marc.talbert@hq.doe.gov

3100 Zinfandel Drive
Suite 600
Rancho Cordova, CA 95670
916.631.3200 phone
916.852.1073 fax

January 22, 2013

Mr. Bob Braddock
Jordan Cove Energy Project, L.P.
125 W. Central Avenue, Suite 380
Coos Bay, OR 97420

Dear Mr. Braddock:

As you are aware, Navigant Consulting, Inc. (Navigant) has been involved in a number of liquefied natural gas (LNG) export projects including Jordan Cove Energy Project, L.P. (JCEP) in helping LNG project developers with their applications to the Department of Energy (DOE) for export of LNG to Non-Free Trade Agreement countries. Our involvement with the projects including JCEP has been primarily to assess the market impact of individual export projects as well as to investigate the pipeline infrastructure and natural gas supply that will be used to serve the requirements of the liquefaction terminals as proposed by the projects. In our analysis, we used Navigant's North American market model built on architecture provided by the GPCM® Natural Gas Market Forecasting System to perform analysis of the impact upon the existing market including prices over the long term.

In performing such analysis for JCEP, as well as other projects located on both coasts and in the Gulf of Mexico, Navigant has a number of comments we would like to make to the Office of Fossil Energy (FE) of the Department of Energy (DOE), which invited comments regarding the LNG Export Study commissioned by the DOE. We invite you to include Navigant's comments in your filing to the DOE in the subject proceeding. While we believe such comments are appropriate for JCEP's project, the comments below are relevant to all LNG export projects currently filed before the DOE for Non-Free Trade approval.

1. That the global market is best suited to determine the 'appropriate' level of U.S. LNG exports.

Rather than relying on any artificially-imposed limits on LNG export volumes, the DOE should allow the global marketplace to determine how much LNG export capacity should be built, who should build it, where it should be built, and ultimately what volumes of LNG exports should

occur. The detailed, macroeconomic component of the DOE's LNG Export Study[1] analyses serves to confirm that LNG exports will provide positive net economic benefits to the U.S. under all modeled scenarios, with increasing benefits associated with the increasing levels of LNG exports that result under the unconstrained export scenarios.[2]

- Arbitrary export level assumptions can yield infeasible study results.

  Whereas the EIA analysis incorporated static, *a priori* assumptions on LNG export volumes, the subsequent NERA analysis component of the DOE's LNG Export Study determined the LNG export levels within its global natural gas market model. As noted by the NERA analysis, "… in many cases, the world natural gas market would not accept the full amount of exports assumed in the EIA scenarios at export prices high enough to cover the U.S. wellhead domestic prices calculated by the EIA."[3] Thus, "[b]ecause the [NERA] study [in some cases] estimated lower export volumes than were specified by [DOE] for the EIA study, U.S. natural gas prices [projected by NERA] do not reach the highest levels projected by EIA."[4]

  For example, LNG exports as projected by the NERA analysis for the EIA Low Shale case never exceed 2.5 bcfd (well below both the 6 bcfd and the 12 bcfd export assumptions driving the EIA price forecasts), and this is the case that produced the most extreme pricing and price change results in the EIA analysis.[5] Thus, EIA's projected average wellhead price increase of 20 percent over the 20-year study for the 12 bcfd export level in the Low Shale case drops to less than 3 percent in NERA's analysis where global gas market modeling results in only achievable LNG export levels.

- Even if DOE were to permit all the applications, the market will decide which facilities get built.

  Obtaining a permit to export is no guarantee that a facility will be built. Companies routinely make their "final investment decision" subsequent to permitting activities. More importantly, market participants (investors, producers, consumers) will optimize

---

[1] DOE uses the term "LNG Export Study" to refer to two reports prepared at its direction: 1) the January 2012 analysis by the Energy Information Administration ("EIA") entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets," requested by the DOE's Office of Fossil Energy in August 2011 ("EIA analysis"); and 2) the December 2012 analysis by NERA Economic Consulting ("NERA") entitled "Macroeconomic Impacts of LNG Exports from the United States," commissioned by DOE under contract ("NERA analysis").
[2] NERA analysis, p. 1.
[3] NERA analysis, p. 3.
[4] NERA analysis, p. 10.
[5] For example, the Low Shale EUR case with the rapid introduction of 12 bcfd of exports resulted in a 54 percent increase versus the baseline wellhead price for the Low Shale EUR case in 2018 (EIA analysis, p. 9), and the Low Shale EUR case baseline average wellhead price over the term of the analysis was itself 40 percent higher than in the Reference case, at $7.37 versus $5.28/MMBtu (EIA analysis, Table B5).

project development activities more efficiently than would any centralized policy or planning direction via regulatory processes. This reality is confirmed by DOE in its 2011 Order conditionally granting export authorization for the Sabine Pass LNG project, in which DOE reiterated that its policy goals include "minimizing federal control and involvement in energy markets" so as to "minimiz[e] regulatory impediments to a freely operating market."[6]

- Even if some overcapacity occurs (for example, due to changes in the market), the market will still decide what levels of exports should occur.

  NERA's modeling effort indicates competitive export levels (that is, LNG export levels that result from the free interplay of supply and demand conditions) could be more or less than the EIA assumptions, but that price levels would remain in a competitive long-term equilibrium range, not linked to oil prices.

  NERA's analysis shows that even with no constraints on the upper end of LNG exports, there would not be any LNG exports in NERA's Low Shale case (with its higher price forecasts in the EIA analysis) except for in the Supply Shock plus Demand Shock international scenario, where exports peak at only 2.5 bcfd (in 2025).

  With plentiful gas supplies (e.g. High Shale case), while exports could exceed the 12 bcfd assumed by EIA, the U.S. price levels themselves still stayed below $6.00/MMBtu by 2035 for all NERA's international scenarios. Even NERA's Supply Shock plus Demand Shock international scenario, with average exports of about 17 bcfd, resulted in average wellhead prices over the 20-year study term of only $5.23/MMBtu.

  Under the EIA's U.S. Reference case, the only scenario where unconstrained exports ever exceeded 12 bcfd is the Supply Shock plus Demand Shock international scenario, where the average wellhead prices from 2015 through 2035 were still less than $6.30/MMBtu (and about $0.10/MMBtu less than for the EIA's Reference Case at a constant 12 bcfd).

- Regardless of modeling estimates, there are likely practical and competitive limits to how much of new LNG capacity will be located in the U.S.

  The global LNG market size in 2010 was about 27 bcfd in imports and exports[7], and is estimated by the International Energy Agency to roughly double in size by 2035. Assuming new U.S. capacity of about half of worldwide growth would be highly optimistic. Navigant's market view is that U.S. LNG export capacity will likely range from 6 to 8 bcfd. We also suggest export opportunities as being time sensitive, and rather than increasing in the future, the LNG export market for export from the U.S. may

---

[6] See DOE/FE Order No. 2961 (Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations), May 20, 2011, at 28.

[7] See NERA analysis, p. 19.

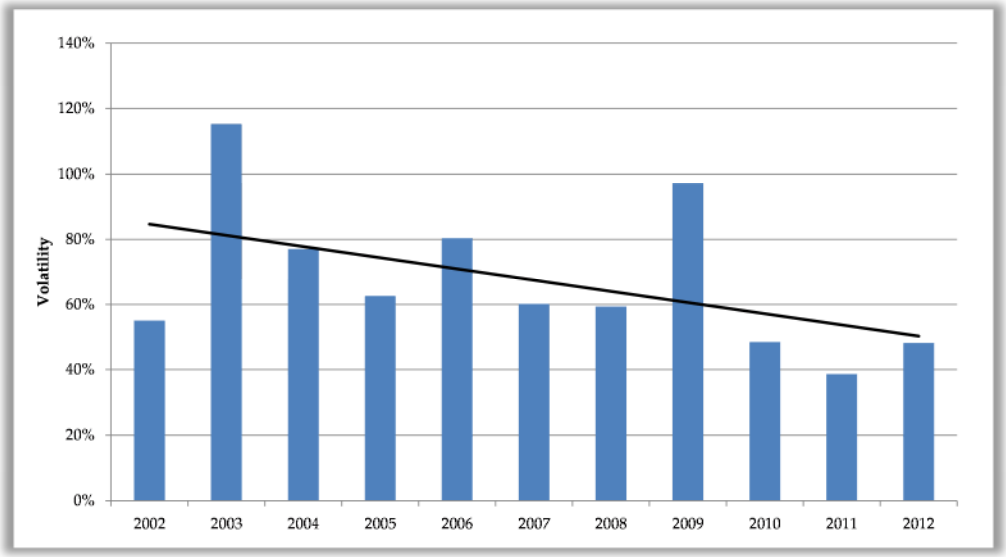
decrease due to supply development in other areas around the world from both known and unknown gas resources.

- <u>There are drawbacks that would result from 'under-permitting' by DOE.</u>

  In addition to the economic benefits of LNG exports, as detailed in the NERA analysis, LNG exports, to the extent they are permitted, will help foster the increasing stability of the domestic natural gas market. Because of the lower exploration and production risk associated with shale gas production resulting from the manufacturing-like nature of shale gas production, once shale plays have been identified, increasing levels of shale gas production should help to lower the volatility of the domestic gas market. LNG exports that increase natural gas demand thus provide two important benefits.

  First, new demand will help stabilize the current over-supply conditions in the domestic marketplace towards a market where supply and demand are in equilibrium. Second, new demand will increase the size of the natural gas market, leading to a continued increase in shale gas' share of total natural gas production, which will lower the price volatility of the gas market by increasing the overall supply responsiveness of the market. As shown in Figure 1 below, recent data seems to support decreasing levels of gas price volatility that correspond well with the recent increases in shale gas production levels. Artificially limiting the amount of LNG exports would be seen to slow the development of shale gas resources, and thus also slow potential future reductions in market price volatility.

Figure 1. Annualized Daily Volatility (Henry Hub)



Source: Navigant

With respect to market policy, a restrictive approach to LNG export approval (i.e., potential under-permitting by DOE) would be inconsistent with the DOE's stated

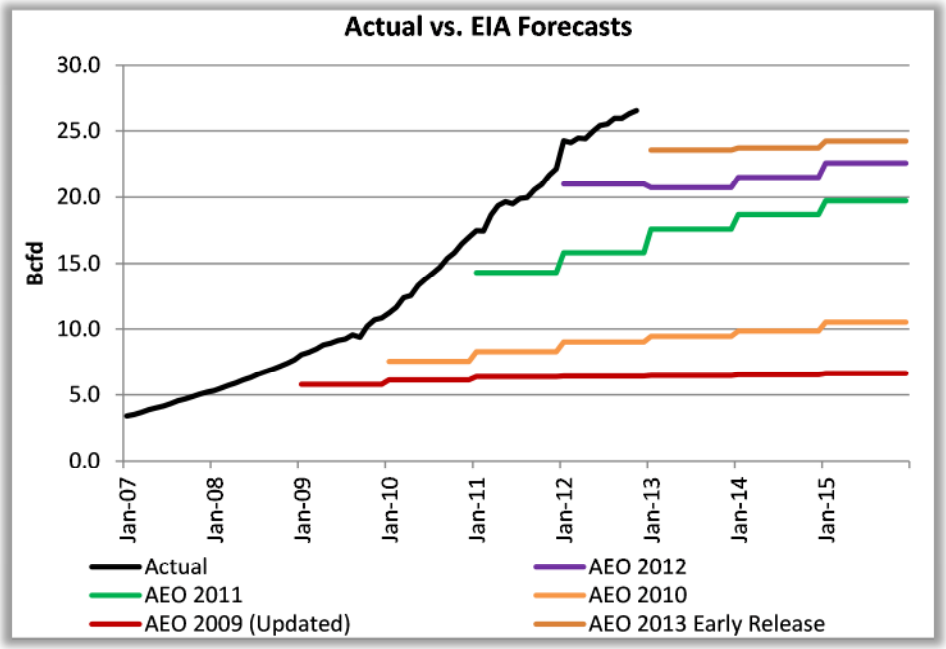
preference[8] for free-market approaches to regulatory oversight. An LNG export authorization process that implies the picking of winners by the regulatory process itself, as opposed to the marketplace, would limit competitive forces and not result in the optimization of project development.

2. The 2011 Reference Case U.S. natural gas supply volume assumptions used in the DOE's LNG Export Study are now drastically understated, and updated assumptions would only strengthen the showing of LNG export benefits.

The EIA's2011 Reference Case supply assumptions used in both analyses drastically understate the reality of today's abundant supply of shale gas. The 2011 Reference Case used was the Annual Energy Outlook (AEO) 2011 forecast shown in Figure Two, below. While the AEO 2011 shale gas production forecasts were already too low with respect to then-existing production levels when made, the continuing strong growth in actual production levels has made the forecast shortfall even larger for subsequent forecast years.

As can be seen in Figure 2, below, the AEO 2011 forecast for 2011 shale gas production (14.3 bcfd) was already eclipsed by actual shale production levels mid-way through 2010; at year-end 2010, actual production levels exceeded the AEO 2011 forecast for 2011 by more than 18 percent. In fact, the AEO 2011 forecast for 2013 shale gas production (17.6 bcfd) was already eclipsed by actual production levels in early 2011. As actual production levels have steadily continued their strong increases, year-end 2012 production levels of 26.5 bcfd were over 50 percent higher than the AEO 2011 forecast for 2013.

Figure 2. U.S. Shale Gas Production (Dry)

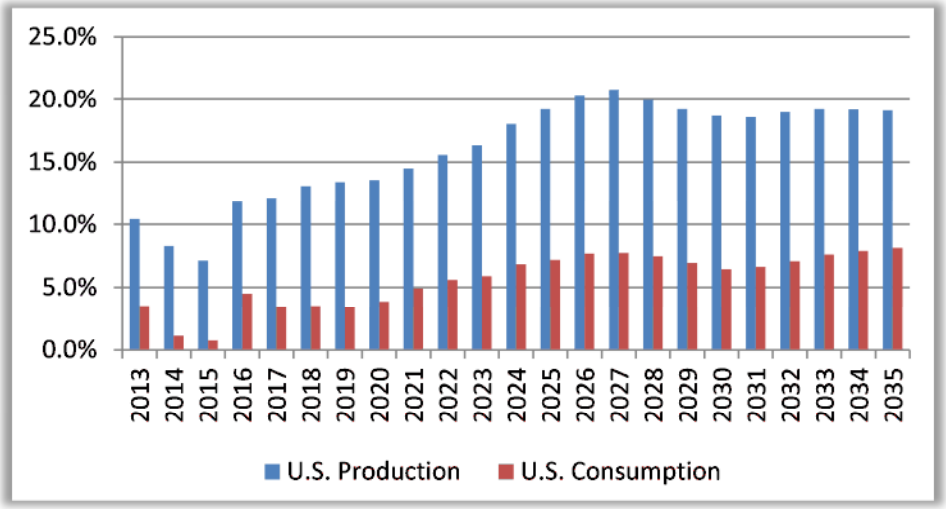


Source: Navigant, EIA

[8] See note 6, supra.

While some criticisms of the DOE's LNG Export Study have focused on the fact that the AEO 2011 *demand assumptions* have been surpassed by those of the AEO 2013, it is important to note that the increase in forecast total natural gas consumption has been far outpaced by the increase in the AEOs' natural gas production forecasts, as shown in Figure 3, below. For the period of 2013-2035, there was an average percentage increase in forecast total domestic natural gas consumption between AEO 2011 and AEO 2013 of 5.6 percent, while the increase in forecast total natural gas production was 16 percent. This important context helps explain why the more recent AEO 2013 assumptions actually indicate the beneficial market impacts that come along with LNG exports.

Figure 3. Percent Increase in Forecasted U.S. Natural Gas Production and Consumption, AEO 2013 vs. DOE Export Study (AEO 2011)



Source: Navigant

Comparing the AEO 2013 forecasts to the AEO 2011 forecasts illustrates an interesting shift in the domestic supply-demand balance. While the entire forecast period of AEO 2011 was characterized by domestic consumption exceeding total production, with a shortfall averaging about 4.0 bcfd from 2013 through 2035 being made up by LNG and pipeline imports to the U.S., in AEO 2013 that situation reverses itself by 2020. More specifically, an initial period of production shortfalls, averaging about 2.7 bcfd, becomes a period of production surpluses averaging about 4.9 bcfd from 2020 through 2035. This period of production surplus, relative to domestic total consumption, coincides generally with the ramping up of LNG exports from about 0.7 bcfd to an average of 3.4 bcfd during 2022 through 2035. Furthermore, the AEO 2013 assumptions of increasing natural gas production relative to domestic consumption and increasing LNG exports, relative to AEO 2011, are associated with a 20 percent lower average natural gas price level from 2013 through 2035 as measured at Henry Hub under AEO 2013 than under AEO 2011.

Thus, the use of a supply forecast more in line with current actual production levels than is the Reference Case (e.g. the AEO 2013 projection) would be expected to result in lower domestic gas prices than estimated in the DOE's LNG Export Study, and consequently increased LNG export volumes to global markets, which would lead to even higher economic benefits to the U.S.

3. Continual increase of production forecasts reflects the underlying natural gas resource abundance.

In any discussion of natural gas production forecasts, it is always instructive to note the key underlying factor behind the continually more optimistic and impressive production forecasts, and that is the reality of today's shale gas boom. The development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together and have been continually improved, has yielded dramatically increased production and fundamentally changed the North American natural gas supply outlook. With U.S. shale gas resources estimated at up to 35 years of annual U.S. natural gas consumption at current levels,[9] pushing U.S. total natural gas resource estimates up to more than 90 years of supply, it is evident that a new era of natural gas sufficiency has arrived. Other estimates of the U.S. and North American natural gas resource base that have been prepared by other industry associations and government institutions are even higher.

Navigant is hopeful that these comments will be helpful for the DOE as it gets set to make decisions of high importance to the LNG export projects, to the natural gas industry, to other parties reliant upon abundant and clean natural gas as a fuel source, and to the country as a whole.

Respectfully submitted,

Gordon Pickering
Director, Energy
Navigant Consulting, Inc.

[9] See e.g. "Golden Rules for a Golden Age of Gas," International Energy Agency, Special Report, May 29, 2012, Table 3.1, putting U.S. shale gas recoverable resources at 24 tcm, or 840 tcf.

AEO2014 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2014 (AEO2014)* Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. The early release provides a basis for the examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or possible technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete *AEO2014* is released in 2014, exploring key uncertainties in the Reference case.

Major highlights of the *AEO2014* Reference case include:

Growing domestic production of natural gas and crude oil continues to reshape the U.S. energy economy, with crude oil production approaching the historical high achieved in 1970 of 9.6 million barrels per day

Ongoing improvements in advanced technologies for crude oil and natural gas production continue to lift domestic supply and reshape the U.S. energy economy. Domestic production of crude oil (including lease condensate) increases sharply in the *AEO2014* Reference case, with annual growth averaging 0.8 million barrels per day (MMbbl/d) through 2016, when it totals 9.5 MMbbl/d (Figure 1). While domestic crude oil production is expected to level off and then slowly decline after 2020 in the Reference case, natural gas production grows steadily, with a 56% increase between 2012 and 2040, when production reaches 37.6 trillion cubic feet (Tcf).The full *AEO2014* will include cases that represent alternative oil and natural gas resource and technology assumptions.

Low natural gas prices boost natural gas-intensive industries

Industrial shipments grow at a 3.0% annual rate over the first 10 years of the projection and then slow to 1.6% annual growth for the rest of the projection. Bulk chemicals and metals-based durables account for much of the increased growth in industrial shipments in *AEO2014*. Industrial shipments of bulk chemicals, which benefit from an increased supply of natural gas liquids, grow by 3.4% per year from 2012 to 2025 in *AEO2014*, as compared with 1.9% in the *Annual Energy Outlook 2013 (AEO2013)* Reference case. The projection assumes growing competition from abroad that flattens output growth in energy-intensive industries after 2030.

The higher level of industrial shipments leads to more natural gas consumption (including lease and plant fuel) in the U.S. industrial sector, increasing from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in *AEO2014*, compared to 9.8 quadrillion Btu in 2025 in *AEO2013*.

Light-duty vehicle energy use declines sharply, reflecting slow growth in vehicle miles traveled and accelerated improvement in vehicle efficiency

AEO2014 includes a new, detailed demographic profile of driving behavior by age and gender as well as new lower population growth rates based on updated U.S. Census Bureau projections. As a result, annual increases in vehicle miles traveled (VMT) for light-duty vehicles (LDVs) in the *AEO2014* Reference case average 0.9% from 2012 to 2040, compared to 1.2% per year in *AEO2013* over the same period. The rising fuel economy of LDVs more than offsets the modest growth in VMT, and LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as compared with the *AEO2013* total of 13.0 quadrillion Btu in 2040 (Figure 2). The full *AEO2014* will include an Issues in Focus discussion of VMT projections that addresses the implications of alternative VMT scenarios.

Figure 1. U.S. petroleum and other liquid fuels supply by source, 1970-2040 (million barrels per day)

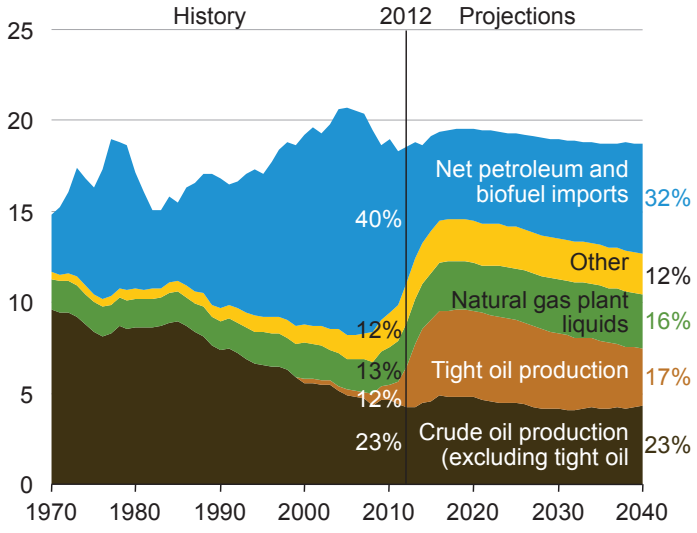
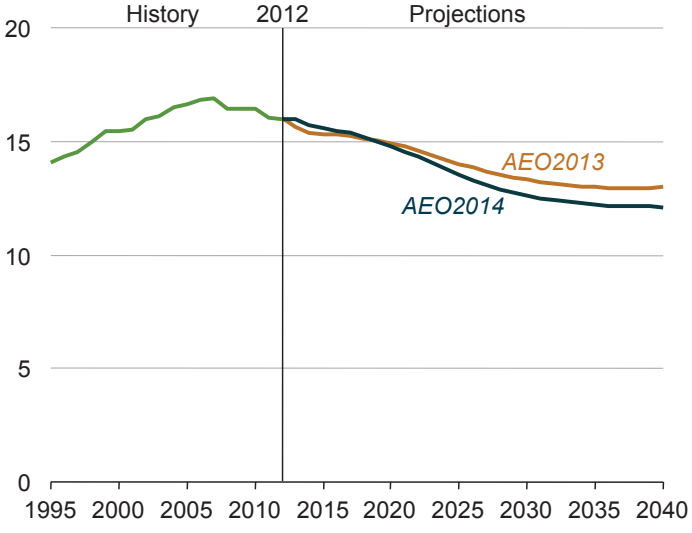


Figure 2. Energy consumption by light-duty vehicles in the United States, *AEO2013* and *AEO2014*, 1995-2040 (quadrillion Btu)



Natural gas overtakes coal to provide the largest share of U.S. electric power generation

Projected low prices for natural gas make it a very attractive fuel for new generating capacity. In some areas, natural gas-fired generation replaces generation formerly supplied by coal and nuclear plants. In 2040, natural gas accounts for 35% of total electricity generation, while coal accounts for 32% (Figure 3). Generation from renewable fuels, unlike coal and nuclear power, is higher in the *AEO2014* Reference case than in *AEO2013*. Electric power generation with renewables is bolstered by legislation enacted at the beginning of 2013 extending tax credits for various renewable technologies; which was passed after the *AEO2013* Reference case had been completed, but was considered in an alternative case in *AEO2013*. The full *AEO2014* will include a variety of cases addressing the implications of alternative market conditions and policies for the electricity generation mix.

Higher natural gas production also supports increases in exports of both pipeline and liquefied natural gas

In addition to increases in domestic consumption in the industrial and electric power sectors, U.S. exports of natural gas also increase in the *AEO2014* Reference case (Figure 4). U.S. exports of liquefied natural gas (LNG) increase to 3.5 Tcf in 2029 and remain at that level through 2040. Pipeline exports of U.S. natural gas to Mexico grow by 6% per year, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040, and pipeline exports to Canada grow by 1.2% per year, from 1.0 Tcf in 2012 to 1.4 Tcf in 2040. Over the same period, U.S. pipeline imports from Canada fall by 30%, from 3.0 Tcf in 2012 to 2.1 Tcf in 2040, as more U.S. demand is met by domestic production. Projected exports are sensitive to assumptions regarding conditions in U.S. and global natural gas markets. The full *AEO2014* will include cases that illustrate the sensitivity of projected natural gas exports to alternative resource, economic, and price scenarios.

With strong growth in domestic crude oil and natural gas production, U.S. use of imported fuels falls sharply

In the *AEO2014* Reference case, U.S. domestic energy production increases from 79.1 quadrillion Btu in 2012 to 102.1 quadrillion Btu in 2040, and net use of imported energy sources, which was 30% in 2005, falls from 16% of total consumption in 2012 to 4% in 2040. In the *AEO2013* Reference case, domestic energy production reached a total of 98.5 quadrillion Btu, and energy imports is projected to decline as a percentage of consumption to 9% in 2040. The larger increase in domestic energy production in *AEO2014* is primarily a result of higher projections of production of natural gas and biomass/other renewables. Crude oil production (including lease condensate) increases from 13.9 quadrillion Btu in 2012 to a peak of 20.5 quadrillion Btu in 2019 before dropping to 16.0 quadrillion Btu in 2040.

With domestic crude oil production rising to 9.5 MMbbl/d in 2016, the import share of U.S. petroleum and other liquids supply falls to about 25%. Domestic production begins to decline after 2019, and the import share of total petroleum and other liquids supply grows to 32% in 2040, still lower than the 2040 level of 37% in the *AEO2013* Reference case. The alternative cases in the full *AEO2014* will illustrate how different assumptions about resources, markets, and policies can dramatically impact projections of import dependence.

Improved efficiency of energy use in the residential and transportation sectors and a shift away from carbon-intensive fuels for electricity generation keep U.S. energy-related carbon dioxide emissions below their 2005 level through 2040

In the *AEO2014* Reference case, total U.S. energy-related emissions of carbon dioxide (CO_2) remain below the 2005 level in every year through 2040. Projected emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level.

In *AEO2014*, CO_2 emissions associated with U.S. industrial activity (including CO_2 emissions associated with the generation of electricity used in the industrial sector) begin to surpass emissions from the transportation sector in the middle of the next

Figure 3. Electricity generation from natural gas and coal, 2005-2040 (billion kilowatthours)

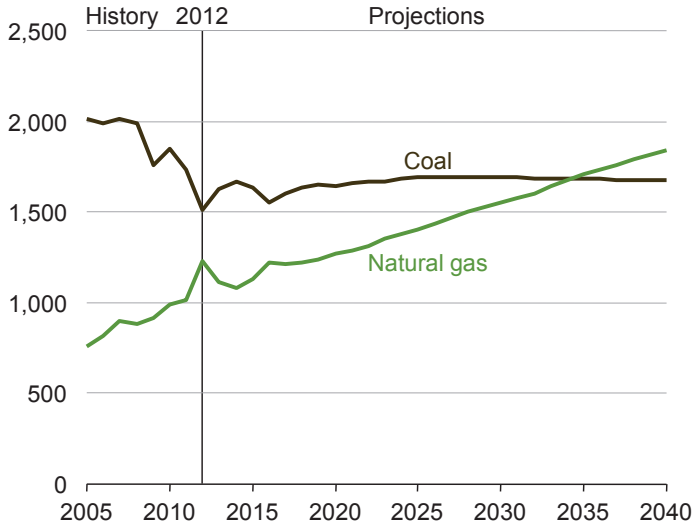
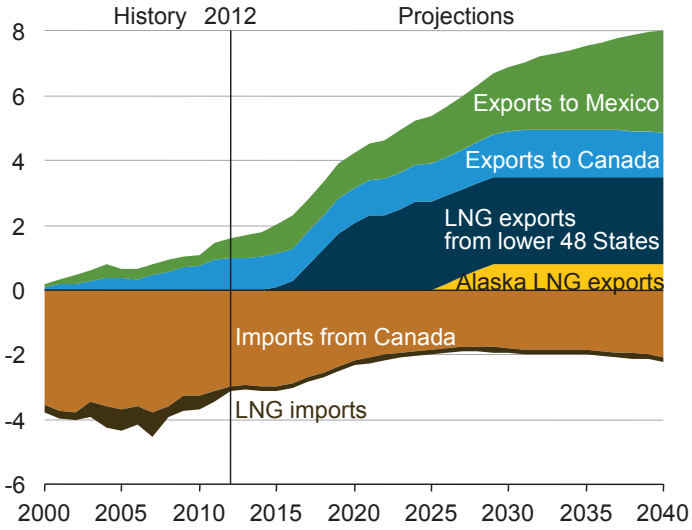


Figure 4. U.S. natural gas imports and exports, 2000-40 (trillion cubic feet)



decade for the first time since the late 1990s. In the transportation sector, as a result of new fuel economy standards, biofuel mandates, and shifts in consumer behavior, emissions from transportation sector use of petroleum and other liquids generally decline or remain stable from 2012 through 2040. Emissions from energy use in the commercial sector increase more rapidly than in the residential sector, and in 2040 emissions from these two sectors are about equal. In the electric power sector, CO_2 emissions from coal combustion decline after 2029 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables. However, the lower level of CO_2 emissions in the electric power sector because of the reduced role for coal is partially offset by less projected generation from nuclear power. Generation from nuclear power in *AEO2014* is 10% below levels in *AEO2013* in 2040 as a result of increased nuclear plant retirements.

Projected growth in real gross domestic product is slightly slower than in AEO2013, but projected per capita GDP and disposable income are higher than in AEO2013 because of a reduced projection for U.S. population growth

Annual growth of real gross domestic product (GDP) from 2012 to 2040 averages 2.4% in the *AEO2014* Reference case, slightly below the *AEO2013* Reference case growth rate over the same period. However, industrial output growth is higher in *AEO2014*, averaging 2.1% per year from 2012 to 2040. Industries that supply equipment for increased natural gas production, as well as industries benefitting from lower natural gas prices, account for much of the higher growth in manufacturing. On a per capita basis, projected annual growth rates for real GDP and disposable income in *AEO2014*, both averaging 1.7% per year, are above the comparable rates in *AEO2013*, reflecting lower projected population growth rate estimates (0.7% in *AEO2014* compared to 0.9% in *AEO2013*) for the 2012-40 period provided by the U.S. Census Bureau.

Introduction

In preparing the *AEO2014* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2014* Reference case and compares it with the *AEO2013* Reference case released in April 2013 (see Table 1 on pages 17-18). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2014* publication is released, to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the *AEO2014* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, expire at the time of those sunset dates). This assumption clarifies the relationship of the Reference case to other *AEO2014* cases and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

As in past editions, the complete *AEO2014* will include additional cases, many of which reflect the effects of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2014*, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates made for the *AEO2014* Reference case include the following:

Macroeconomic

- Revised U.S. Census Bureau population projections.[2] The population projection for 2040 in the *AEO2014* Reference case is almost 6% below the 2040 projection used for the *AEO2013* Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available.[3] Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector.[4]

[1]See "Congressional & Other Requests," http://www.eia.gov/analysis/reports.cfm?t=138.

[2]The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), http://www.census.gov/newsroom/releases/archives/population/cb12-243.html.

[3]U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.

[4]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use.[5]
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports.[6, 7]
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in *AEO2014* because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new residential furnace standards.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS).[8]
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks.[9]
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to VMT projections for LDVs, based on an analysis of VMT by age cohorts and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with *AEO2013*. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in *AEO2014* compared with 41% growth in *AEO2013*.
- Added LNG as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phase-out of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles—including (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, basing flow decisions on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices.[10]

[5]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[6]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.

[7]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

[8]U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.

[9]Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (natural gas plant liquids [NGPL] + liquefied refinery gases [LRG]) and market (NGL + refinery olefins) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in *AEO2014* have been relabeled to conform to this newly adopted definition.

[10]Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data.[11]
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling.[12]
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners.[13]
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis[14]—with lower production levels than in *AEO2013*, as more recent experience with these emerging technologies indicates higher costs than previously assumed.[15]
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules.[16]

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/Independent System Operator requirements,[17] and capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirement of nuclear capacity in several regions to better reflect the impact of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS)[18] covering the electric power sector to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013[19]—including revision of PTC expiration dates for each PTC-eligible technology to reflect the concept of projects being declared "under construction" as opposed to being placed "in service" and extension of the expiration date of the PTC for wind generation projects by one year.

Economic growth

Macroeconomic projections in the *Annual Energy Outlook (AEO)* are trend projections, with no major shocks assumed and with potential growth determined by the economy's supply capability. Growth in aggregate supply depends on increases in the labor force, growth of capital stocks, and improvements in productivity. Long-term demand growth depends on labor force growth,

[11]After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in "sweet spots" are developed earlier than lower quality resources, based on net present value.

[12]High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.

[13]Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.

[14]Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.

[15]EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.

[16]When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at these facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

[17]North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf.

[18]U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.

[19]U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

income growth, and population growth. *AEO2014* uses the U.S. Census Bureau's December 2012 middle population projection. The U.S. Census Bureau revised its population projections primarily to reflect lower assumptions regarding international net migration.

In *AEO2014*, U.S. population is expected to grow at an annual rate of 0.7% from 2012 to 2040, or 0.2 percentage points lower than the 0.9% average annual population growth rate in *AEO2013*. As shown in Figure 5, most of the change from *AEO2013* to *AEO2014* is in the younger age cohorts. Real GDP, labor force, and productivity in *AEO2014* grow by average annual rates of 2.4%, 0.6%, and 1.8%, respectively, from 2012 to 2040.

Total industrial production growth (which includes manufacturing, construction, agriculture, and mining) in *AEO2014* is higher than projected in *AEO2013*, primarily as a result of more rapid growth in manufacturing output, with most of the difference accounted for by machinery, transportation equipment, fabricated metals, and bulk chemicals. Those industries, in addition to being trade-sensitive, supply equipment or raw materials used in oil and gas production or otherwise benefit from lower natural gas prices. In 2040, the manufacturing share of total gross output is 18% in *AEO2014*, compared with 16% in *AEO2013*.

Energy prices

Crude oil

Oil prices are influenced by several factors, including some that have mainly short-term impacts. Other factors, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), can affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, with considerable complexity in the evolution of underlying supply and demand expectations. For petroleum and other liquids, the key determinants of long-term supply and prices can be summarized in four broad categories: the economics of non-OPEC supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

Key assumptions driving global crude oil markets in the *AEO2014* Reference case over the projection period include: average economic growth of 1.9% per year for major U.S. trading partners[20] and average economic growth of 4.0% per year for other U.S. trading partners. Growth in petroleum and other liquids use occurs almost exclusively outside the Organization for Economic Cooperation and Development (OECD) member countries, with 1.8% average annual growth in petroleum and other liquids consumption by non-OECD countries, including significantly higher average annual consumption growth in both China and India.

Petroleum and other liquids production in *AEO2014* from non-OPEC countries, particularly the United States, increases to levels above those in *AEO2013*. As a result, the OPEC market share declines to less than 40% in the near term before starting to rise again after 2016. The Brent crude oil spot price decreases from $112 per barrel (bbl) in 2012 to $92/bbl in 2017 in the Reference case (in 2012 dollars), then increases to $141/bbl in 2040 (or about $235/bbl in nominal dollars) as growing demand leads to the development of more costly resources (Figure 6). However, those resources are not as costly to develop as projected in *AEO2013*.

Figure 5. Comparisons of population growth by projection period and age cohort in the *AEO2014* and *AEO2013* Reference cases (*AEO2014* growth minus *AEO2013* growth)

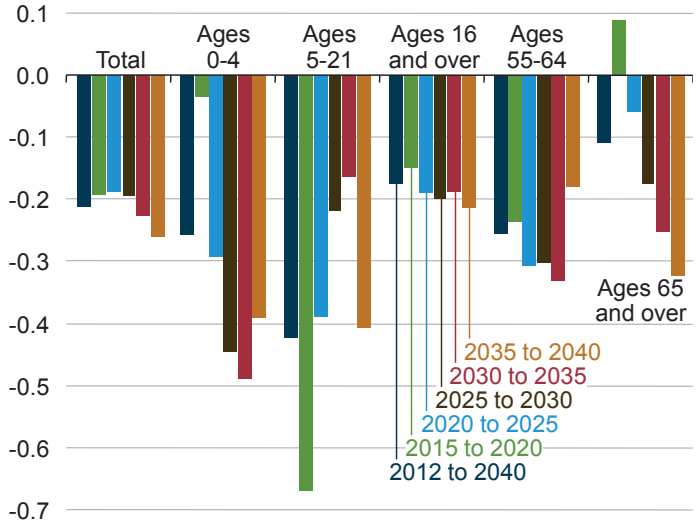
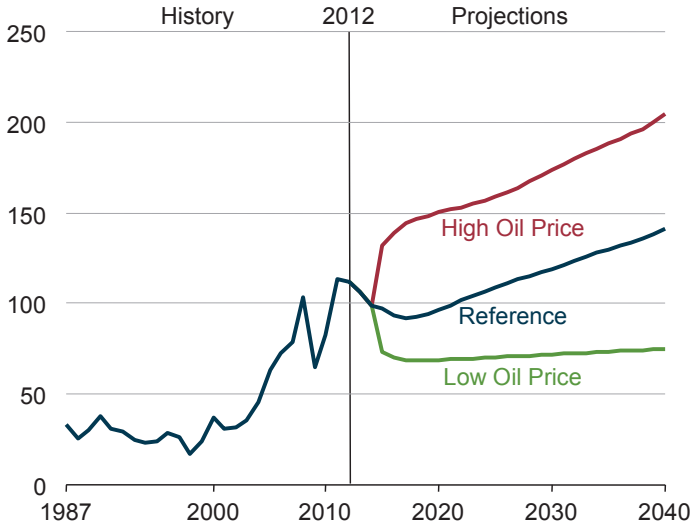


Figure 6. Average annual Brent spot crude oil prices in three cases, 1987-2040 (2012 dollars per barrel)



[20]Major trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

Petroleum and other liquids products

With lower crude oil prices and lower gasoline demand projected in the *AEO2014* Reference case, the real end-use price of motor gasoline in the United States declines to $3.03 per gallon (2012 dollars) in 2017, then rises to $3.90 per gallon in 2040 (compared to $4.40 per gallon in 2040 in *AEO2013*). The end-use price of diesel fuel in the transportation sector follows a similar pattern, dropping to $3.50 per gallon in 2017 and then rising to $4.73 per gallon in 2040 (compared to $5.03 per gallon in *AEO2013*). Although both gasoline and diesel prices dip modestly in the early years of the projection period, they increase steadily thereafter. The diesel share of total domestic petroleum and other liquids production rises, and the gasoline share falls, mostly as a result of the greenhouse gas (GHG) and CAFE standards for LDVs beginning in model year 2017. Increasing demand for diesel puts pressure on refiners to increase diesel yields and results in a rising difference between diesel prices and gasoline prices from 2017 to 2025.

Legislated targets for cellulosic fuels use mandated by the Energy Independence and Security Act of 2007 (EISA2007) are not attained, as the U.S. Environmental Protection Agency (EPA)[21] continues to make use of the flexibility provided in the statute to adjust those requirements.

Natural gas

The Henry Hub spot price for natural gas in the *AEO2014* Reference case is higher than projected in *AEO2013* through 2037, with price increases in the near term driven by faster growth of consumption in the industrial and electric power sectors and, later, growing demand for export at LNG facilities. A sustained increase in production follows, leading to slower price growth over the rest of the projection period.

The Henry Hub spot natural gas price in *AEO2014* reaches $4.80 per million Btu (MMBtu) (2012 dollars) in 2018, which is 77 cents/MMBtu higher than in *AEO2013*. The stronger near-term price growth is followed by a lagged increase in supply from producers, eventually causing prices to settle at $4.38/MMBtu in 2020, which is still notably higher than in *AEO2013*.

After 2020, increases in natural gas spot prices are driven by continued but slower growth in U.S. demand and net exports. The Henry Hub spot natural gas price rises to $7.65/MMBtu in 2040, an increase of $3.28 from 2020 but 4% below the 2040 price projection in *AEO2013*. In *AEO2014*, production grows to 37.5 Tcf in 2040, compared with 33.1 Tcf in *AEO2013*. A price increase starting in 2033 is far less pronounced than was projected in *AEO2013*, in part because the growth in net exports from the United States slows significantly.

Regional spot price projections throughout the United States follow the same general pattern as the Henry Hub spot price. However, the average Lower 48 spot price generally increases at a slightly slower rate than the Henry Hub spot price, because regional production growth outside those areas that serve the Henry Hub is projected to be somewhat faster than the growth in production that serves the Henry Hub.

Coal

The average minemouth price of coal increases by 1.4% per year in the *AEO2014* Reference case, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040 (2012 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the *AEO2014* Reference case is similar to the trend in the *AEO2013* Reference case, but the average price through the projection period in *AEO2014* is generally lower, primarily reflecting a lower price outlook for coking coal.

Relative to minemouth prices, the average delivered price of coal to all sectors (excluding exports) increases at a slightly slower pace of 1.0% per year, from $2.60/MMBtu in 2012 to $3.43/MMBtu in 2040. The slower growth rate primarily reflects modest growth in average coal transportation rates, which increase by 0.2% per year in *AEO2014*—from $0.83/MMBtu in 2012 to $0.89/MMBtu in 2040—as a result of gradually increasing fuel costs and changes over time in the pattern of coal distribution.

U.S. coal exports, which have surged in recent years from 50 million short tons in 2005 to a record 126 million short tons (MMst) in 2012, have become an increasingly important source of revenue for both U.S. coal producers and coal transportation companies (primarily railroads and barge companies). In 2012, coal export revenues totaled about $15 billion, representing about 25% of all U.S. coal revenues, despite the fact that coal exports in 2012 represented only 12% of total U.S. production (short tons). In the *AEO2014* Reference case, U.S. coal export prices increase by 1.2% per year, to $6.40/MMBtu in 2040.

Electricity

Following the decline of natural gas prices since 2008, real average delivered prices for electricity have dropped consistently (although more gradually) since 2009, to 9.8 cents per kilowatthour (kWh) in 2012. Retail electricity prices are influenced by fuel prices, and particularly by natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which, and the timeframe over which, they are linked. Those factors include the share of natural gas generation in a region, the level of costs associated with the electricity transmission and distribution systems,

[21] U.S. Environmental Protection Agency, "2014 Standards for the Renewable Fuel Standard Program: Proposed Rule," 40 CFR Part 80 [EPA-HQ-OAR-2013-0479; FRL-9900-90-OAR], RIN 2060-AR76, *Federal Register,* Vol. 78, No. 230 (Washington, DC: November 29, 2013), pp. 71732-71784, http://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-28155.pdf.

the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for changes in fuel prices to affect electricity prices, and the impacts can vary from region to region.

In the *AEO2014* Reference case, electricity prices are higher throughout the projection than they were in the *AEO2013* Reference case. Natural gas prices for electricity generators are higher than those in *AEO2013* in the first few years but fairly similar in the long term. Reliance on natural gas-fired generation remains strong, as a result of additional near-term retirements of coal-fired and nuclear capacity, and natural gas prices continue to influence electricity prices. In the long term, both natural gas prices and electricity prices rise. Electricity prices, which in 2030 are 10.4 cents/kWh (2012 dollars) in the *AEO2014* Reference case, compared with 9.9 cents/kWh in the *AEO2013* Reference case, continue rising to 11.1 cents/kWh in 2040 in *AEO2014*, compared with 11.0 cents/kWh in the *AEO2013* Reference case.

The *AEO2014* Reference case includes an updated calculation of electricity prices in competitive regions that better represents payments required to maintain reserve capacity, contributing to higher projected electricity prices relative to *AEO2013*. In addition, the updated regional reserve margin requirements in *AEO2014* generally are higher and thus more costly than those in *AEO2013*.

Delivered energy consumption by sector[22]

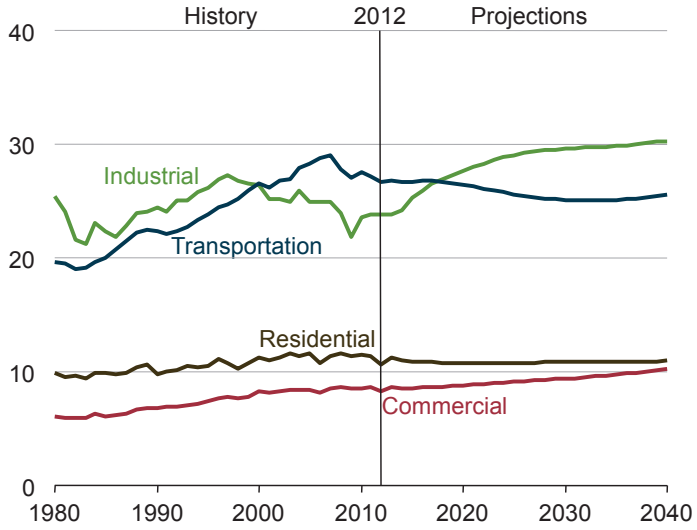
Transportation

Delivered energy consumption in the transportation sector declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the *AEO2014* Reference case (Figure 7) because of a significant decline in energy consumption by LDVs that more than offsets growth in energy consumption for other modes. The decline in transportation sector delivered energy consumption is markedly different from the historical trend of 1% average annual growth in transportation energy consumption from 1975 to 2012.[23] Transportation energy consumption is considerably lower in *AEO2014* than projected in the *AEO2013* Reference case (27.1 quadrillion Btu in 2040) with energy consumption by nearly all transportation modes reduced in *AEO2014* as a result of lower macroeconomic indicators, higher energy efficiency, changing demographics, and a revised calculation of VMT.

LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, compared with 13.0 quadrillion Btu in 2040 in the *AEO2013* Reference case. GHG emission standards and CAFE standards increase new LDV fuel economy through model year 2025 and beyond, with more fuel-efficient new vehicles gradually replacing older vehicles on the road and raising the fuel efficiency of the LDV stock by an average of 2.0% per year, from 21.5 miles per gallon (mpg) in 2012 to 37.2 mpg in 2040. The higher fuel economy of LDVs more than offsets increases in VMT that average 0.9% per year from 2012 to 2040, a reduction from the *AEO2013* projection that reflects changes in driving behavior related to changing demographics. The average fuel economy of the vehicle stock is higher, and travel by LDVs is lower in *AEO2014* than projected in *AEO2013*. The large decline in LDV energy consumption in *AEO2014* shrinks the LDV modal share of total transportation energy consumption from 60% in 2012 to 47% in 2040.

LDVs powered by motor gasoline remain the dominant vehicle type in the *AEO2014* Reference case, retaining a 78% share of new LDV sales in 2040, down from their 82% share in 2012. The fuel economy of LDVs powered by motor gasoline continues to increase, and advanced technology fuel efficiency subsystems are added, such as micro hybridization, which is installed on 42% of new motor gasoline LDVs in 2040. The numbers of LDVs powered by fuels other than gasoline, such as diesel, electricity, or E85, or equipped with hybrid drive trains, such as plug-in hybrid or gasoline hybrid electric, increase modestly from 18% of new sales in 2012 to 22% in 2040. Ethanol FFVs account for 11% of overall vehicle sales in 2040, followed by hybrid electric vehicles (excluding micro hybrids) at 5% of new sales in 2040, up from 3% in 2012, diesel vehicles at 4% in 2040, up from 2% in 2012, and plug-in hybrid vehicles and electric vehicles at about 1% each, both up from negligible shares in 2012. New vehicle sales shares are generally similar in *AEO2014* and *AEO2013* but with moderate variation. In *AEO2013*, the new vehicle sales share of motor gasoline vehicles was 80% in 2040 (with 36% of those vehicles including micro hybridization), followed by 7% for ethanol FFVs, 6% for hybrid electric, 3% for diesel, 2% for plug-in hybrids, and 1% for electric vehicles. The differences from *AEO2013* to *AEO2014* result from different fuel prices,

Figure 7. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



[22]The amount of energy delivered to the sector; no adjustment is made for the fuels consumed to produce electricity or district sources.

[23]S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book*, ORNL-6989 (Edition 32 of ORNL-5198) (Oak Ridge, TN: July 2013), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2012."

updated manufacturer product offerings, changing technology attributes, and an updated view of consumer perceptions of infrastructure availability for E85 vehicles.

Delivered energy demand for HDVs in *AEO2014* increases from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, similar to the 2040 level of 7.6 quadrillion Btu in *AEO2013,* and represents the largest growth among all transportation modes. Growth in industrial output in *AEO2014* leads to solid growth in HDV VMT, averaging 1.9% per year from 2012 to 2040. HDV energy demand is tempered somewhat by an average 0.5% annual increase in fuel economy from 2012 to 2040 as a result of GHG emission and fuel efficiency standards for medium- and heavy-duty vehicles and engines. Competitive natural gas prices significantly increase the demand for LNG and compressed natural gas in *AEO2014*, from an insignificant share in 2012 to 8% of HDV energy consumption in 2040, which is less than the 13% share projected in *AEO2013* because of the lower prices of competing fuels in *AEO2014*. The rapid growth of energy consumption by HDVs in *AEO2014* increases their modal share of total transportation energy consumption from 20% in 2012 to 29% in 2040.

Energy demand for aircraft grows in the *AEO2014* Reference case from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, which is less than the *AEO2013* projection of 2.9 quadrillion Btu in 2040. Personal air travel (billion seat-miles) grows by an average of 0.7% per year in *AEO2014*, but improved fuel efficiency (by an average of 0.5% per year) reduces the effect on energy consumption. The difference between *AEO2014* and *AEO2013* stems from lower demand for personal air travel in *AEO2014* as a result of lower economic growth. The aircraft share of total transportation energy consumption in *AEO2014* increases from 9% in 2012 to 11% in 2040.

Energy consumption by marine vessels increases from 0.9 quadrillion Btu in 2012 to 1.0 quadrillion Btu in 2040 in *AEO2014*, reflecting the impacts of increased foreign trade on international shipping and higher incomes on recreational boating. Pipeline energy use rises modestly, from 0.7 quadrillion Btu in 2012 to 0.8 quadrillion Btu in 2040, as increasing volumes of natural gas are produced but closer to end-use markets. Rail energy consumption remains nearly flat at 0.5 quadrillion Btu from 2012 to 2040 in *AEO2014*, as a result of a plateau in coal shipments and increases in fuel efficiency, which offset growth in rail transportation of other industrial commodities.

Other energy use in the transportation sector, which includes both lubricants and military energy use, increases from 0.8 quadrillion Btu in 2012 to 0.9 quadrillion Btu in 2040. Marine, pipeline, other transportation, and rail energy use all are relatively minor pieces of the overall transportation energy consumption picture in *AEO2014*, each accounting for less energy demand than in the *AEO2013* projections, as a result of lower economic growth in the *AEO2014* Reference case.

Industrial

Approximately one-third of total U.S. delivered energy in 2012, 23.6 quadrillion Btu, was consumed in the industrial sector, which includes manufacturing, agriculture, construction, and mining. In the *AEO2014* Reference case, total industrial delivered energy consumption grows to 30.2 quadrillion Btu in 2040—1.5 quadrillion Btu, or 5%, higher than the *AEO2013* Reference case projection. The industrial sector becomes the largest energy consuming sector by 2018 and remains so for the rest of the projection period.

The growth rate for total industrial energy consumption in the *AEO2014* Reference case is greater than in *AEO2013* as a result of lower natural gas prices, which boost industrial production, and greater availability of natural gas liquids (NGL).[24] The industry that consumes the most energy is bulk chemicals, where total energy consumption grows from 5.5 quadrillion Btu in 2012 to 7.0 quadrillion Btu in 2040. In the *AEO2014* Reference case, energy consumption by the bulk chemicals industry in 2040 is 1.2 quadrillion Btu higher than projected in *AEO2013*.

Total manufacturing shipments in the *AEO2014* Reference case also increase more rapidly than in the *AEO2013* Reference case, from $4.5 trillion in 2012 to $8.4 trillion in 2040, or 87%. The growth rate for shipments in energy-intensive manufacturing is one-half the rate for non-energy-intensive manufacturing, reflecting the continuing shift toward less energy-intensive manufacturing, such as transportation equipment, computers, and other durable metal goods. The rate of growth in all manufacturing industries is higher from 2012 to 2025 than after 2025, as a result of increased international competition in the later years of the projection.

Shipments in the energy-intensive industries—refining, food, paper, bulk chemicals, glass, cement and lime, iron and steel, and aluminum—grow from $1.6 trillion in 2012 to $2.3 trillion in 2040 in the *AEO2014* Reference case, an annual rate of growth of 1.3%, compared to 1.0% in the *AEO2013* Reference case. The rate of increase in *AEO2014* is much faster from 2012 to 2025 (2.0% per year) than from 2025 to 2040 (0.7% per year). Shipments of bulk chemicals, iron and steel, and aluminum peak in the late 2020s and decline thereafter, as export growth slows. Total energy consumption in the energy-intensive industries increases by 0.7% per year from 2012 to 2040, with almost all the growth occurring in the 2012-25 period.

Energy use for heat and power in the energy-intensive industries grows from 11.5 quadrillion Btu in 2012 to 13.1 quadrillion Btu in 2040, averaging 0.9% per year from 2012 to 2025 and 0.1% per year from 2025 to 2040. With energy intensity declining in the energy-intensive industries, largely because of improvements in efficiency, the growth of energy use for heat and power is slower than the growth of shipments. In the bulk chemicals and petroleum refining industries, demand for feedstocks—which include HGL,[25] petroleum (usually naphtha), and natural gas—grows by 1.3% per year on average, from 3.5 quadrillion Btu in 2012 to 5.0

[24]Natural gas liquids include ethane, propane, normal butane, isobutane, and pentanes plus.
[25]HGL includes NGL, ethane, propane, normal butane, isobutane, natural gasoline (pentanes plus), and olefins.

quadrillion Btu in 2040, with average increases of 2.9% per year from 2012 to 2025 followed by a decline from 2025 to 2040 averaging 0.1% per year.

Only the bulk chemical industry uses liquid feedstocks (HGL and petrochemical feedstocks), which are used to produce organic chemicals, inorganic chemicals, resins, synthetic rubber, and fibers. With demand for bulk chemicals higher in the *AEO2014* Reference case than in *AEO2013*, consumption of liquid feedstocks also is higher in *AEO2014*. HGL feedstocks and petrochemical feedstocks (naphtha and heavier inputs) often can be interchanged to some degree, depending on price and the product slate. In the *AEO2014* Reference case, HGL feedstock consumption totals 2.2 quadrillion Btu in 2012, 2.9 quadrillion Btu in 2025, and 2.7 quadrilion Btu in 2040; and petrochemical feedstock use totals 0.8 quadrillion Btu in 2012, 1.5 quadrillion Btu in 2025, and 1.6 quadrillion Btu in 2040.

Shipments from the nonenergy-intensive manufacturing sector increase by 2.7% per year from $2.9 trillion in 2012 to $6.1 trillion in 2040 in the *AEO2014* Reference case, with growth rates of 3.2% per year from 2012 to 2025 and 2.3% per year after 2025. Energy consumption for nonenergy-intensive manufacturing grows from 3.6 quadrillion Btu in 2012 to 4.9 quadrillion Btu in 2040, averaging 1.0% per year—the same rate as in the *AEO2013* Reference case. In parallel with the growth of shipments, energy consumption in the nonenergy-intensive manufacturing sector grows more rapidly from 2012 to 2025 (1.3% per year) than from 2025 to 2040 (0.8% per year).

In the nonmanufacturing industries—agriculture, construction, and mining—shipments grow by 1.6% per year from 2012 to 2040 in the *AEO2014* Reference case, slightly less than the annual growth rate of 1.8% in the *AEO2013* Reference case over the same period. Growth in the *AEO2014* Reference case averages 2.8% per year from 2012 to 2025 and slows to 0.7% per year after 2025. Energy consumption by nonmanufacturing industries grows by 1.2% per year, from 4.8 quadrillion Btu in 2012 to 6.8 quadrillion Btu in 2040. While energy intensity declines somewhat in the agriculture and construction industries, it increases in the mining industry as exploration activities move over time to less desirable—and more energy-intensive—resources.

Residential

Residential delivered energy consumption remains roughly constant in the *AEO2014* Reference case from 2012 to 2040. However, consumption levels are lower than those in *AEO2013* for most fuels. In addition to lower population growth projections, the lower consumption levels in the *AEO2014* Reference case are explained in part by incorporation of the 2009 RECS data, which include characteristic information such as the mix of building types in each region of the country, equipment stocks, and appliance saturation levels, as well as energy consumption estimates for three major end uses—space heating, space cooling, and water heating. In addition, weather-related demand elasticities for heating and cooling also have been updated to better align *AEO* projections with those in EIA's *Short-Term Energy Outlook.*

The *AEO2014* Reference case removes the 2013 federal efficiency standard for condensing gas furnaces, based on challenges to the DOE rulemaking, first by an association of natural gas utilities and later by equipment distributors. Although natural gas use tends to be lower when the standard is included, consumption in the *AEO2014* Reference case (without the standard) is lower than in *AEO2013* (with the standard) through most of the projection period, largely because of changes in the end-use allocations from the 2009 RECS.

An EIA-contracted report[26] provides updated estimates of the installed stock and consumption of several miscellaneous electric loads, including televisions, computers, and related equipment. This update generally resulted in lower electricity consumption for these appliances than was projected in the *AEO2013* Reference case.

For *AEO2014*, outdoor lighting was added to the residential model as a separate application. In addition, cost and performance attributes for most residential lighting types were updated on the basis of EIA-contracted technology reports[27] and market studies from DOE.[28] Lower costs and wider availability of LEDs result in lower energy consumption after 2020 in *AEO2014* relative to *AEO2013*.

Commercial

Commercial sector delivered energy consumption grows from 8.3 quadrillion Btu in 2012 to 10.2 quadrillion Btu in 2040 in the *AEO2014* Reference case, similar to the *AEO2013* Reference case despite slower growth in the near term. Commercial electricity consumption increases by 0.8% per year from 2012 to 2040 in *AEO2014*, lower than the 1.0% average annual growth in commercial floorspace, in part because projected demand for cooling and lighting is lower than in *AEO2013*. Also, more rapid reductions in energy use for personal computers than previously estimated, largely because of a shift to more efficient portable devices, result in a projected 5.6% annual decline in electricity demand for commercial PC equipment in the *AEO2014* Reference case. Following

[26]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in NEMS* (Washington, DC, May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[27]U.S. Energy Information Administration, "Updated Buildings Sector Appliance and Equipment Costs and Efficiency" (Washington, DC: August 7, 2013), http://www.eia.gov/analysis/studies/buildings/equipcosts/.

[28]U.S. Department of Energy, Energy Efficiency & Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf, and *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

slower-than-expected adoption of new data centers as a result of the recent recession, installations of new data center servers increase more in *AEO2014* than in *AEO2013*.

Growth of natural gas consumption in the commercial sector averages roughly 0.7% per year from 2012 to 2040, similar to the *AEO2013* Reference case.

Energy consumption by primary fuel

Total primary energy consumption grows by 12% in the *AEO2014* Reference case, from 95 quadrillion Btu in 2012 to 106 quadrillion Btu in 2040—1.3 quadrillion Btu less than in *AEO2013* (Figure 8). The fossil fuel share of energy consumption falls from 82% in 2012 to 80% in 2040, as consumption of petroleum-based liquid fuels declines, largely as a result of slower growth in VMT and increased vehicle efficiency.

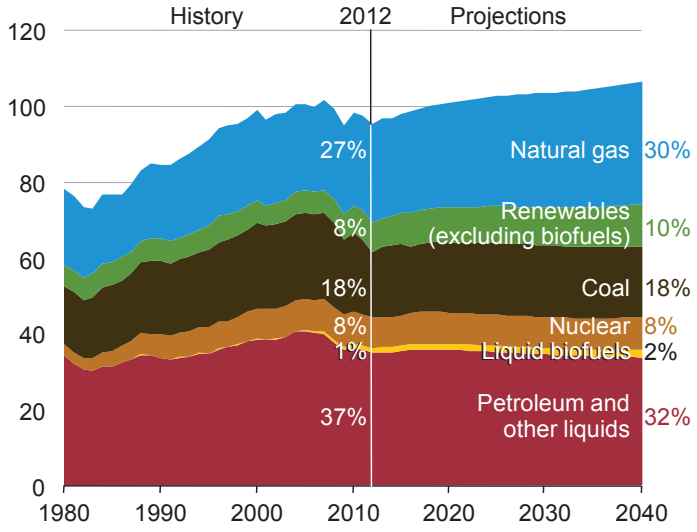
Total U.S. consumption of petroleum and other liquids, which was 35.9 quadrillion Btu (18.5 MMbbl/d) in 2012, increases to 36.9 quadrillion Btu (19.5 MMbbl/d) in 2018, then declines to 35.4 quadrillion Btu (18.7 MMbbl/d) in 2034 and remains at that level through 2040. Total consumption of domestically produced biofuels increases slightly through 2022 and then remains relatively flat. Production of cellulosic biofuels is currently well under 1% of the EISA2007 targets.[29] With the PTC for cellulosic biofuels scheduled to expire at the end of 2013, production of cellulosic biofuels remains below the EISA2007 target through the projection period. Within the transportation sector, which dominates demand for petroleum and other liquids, there is a shift from motor gasoline (losing more than 10% of its share of total transportation petroleum and other liquids demand over the projection) to distillate (gaining slightly less than 10% of the total). The increased use of compressed natural gas and LNG in vehicles also offsets about 3% of petroleum and other liquids consumption in the transportation sector in 2040.

Domestic natural gas consumption in the *AEO2014* Reference case rises from 25.6 Tcf in 2012 to 31.6 Tcf in 2040 (about 2.1 Tcf higher than in the *AEO2013* Reference case). The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 9.3 Tcf in 2012 to 11.2 Tcf in 2040, with a portion of the growth attributable to the retirement of 50 gigawatts of coal-fired capacity by 2021. Natural gas consumption in the industrial sector is also higher in *AEO2014* than was projected in *AEO2013*, as a result of the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slower growth of natural gas prices. Industries such as bulk chemicals, which use natural gas as a feedstock, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection.

Total coal consumption increases from 17.3 quadrillion Btu (891 MMst) in 2012 to 18.7 quadrillion Btu (979 MMst) in 2040 in the *AEO2014* Reference case. Coal consumption, mostly for electric power generation, falls off in 2016, the first year of the MATS. After 2016, coal-fired electricity generation increases slowly over the next 10 years as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2040 is 17.3 quadrillion Btu (909 MMst) in the *AEO2014* Reference case. This level is about 1.4 quadrillion Btu (75 MMst) lower than in the *AEO2013* Reference case. No coal is consumed for CTL technology in the *AEO2014* Reference case.

With the implementation of the federal RFS for transportation fuels and state renewable portfolio standards for electricity generation, consumption of marketed renewable fuels grows by 1.4% per year in the *AEO2014* Reference case. Marketed renewable energy includes wood, municipal waste, other biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind power in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 1.5 quadrillion Btu is included with petroleum and other liquid fuels consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.9 quadrillion Btu in 2012 to 4.5 quadrillion Btu in 2040, with biomass accounting for 27% of the growth and wind 39%. Generation of electricity from solar photovoltaic energy shows the fastest growth, starting from a small base and accounting for 7.5% of total electricity generation from all nonhydropower renewable energy sources in 2040.

Figure 8. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu)



Energy intensity

From 1992 to 2012, energy use per dollar of GDP declined on average by 1.9% per year, in large part because of shifts within the economy from manufactured goods to the service sectors,

[29]Based on 2010, 2011, 2012, and 2013 evaluations of the volumes of cellulosic biofuels available, EPA substantially reduced the cellulosic biofuels obligation under the RFS for those years, with the 2013 obligation set at 6 million ethanol-equivalent gallons, less than 1% of the legislated target of 1 billion gallons.

which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was almost 12 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30% in 1992 to 22% in 2012 (including a slight increase from 2009 to 2012). In the *AEO2014* Reference case, the industrial share of total shipments increases to 24% in 2016, after which it declines again, at a very slow rate, to 23% in 2040. Energy use per 2005 dollar of GDP declines by 43% from 2012 to 2040 in *AEO2014* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less-energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

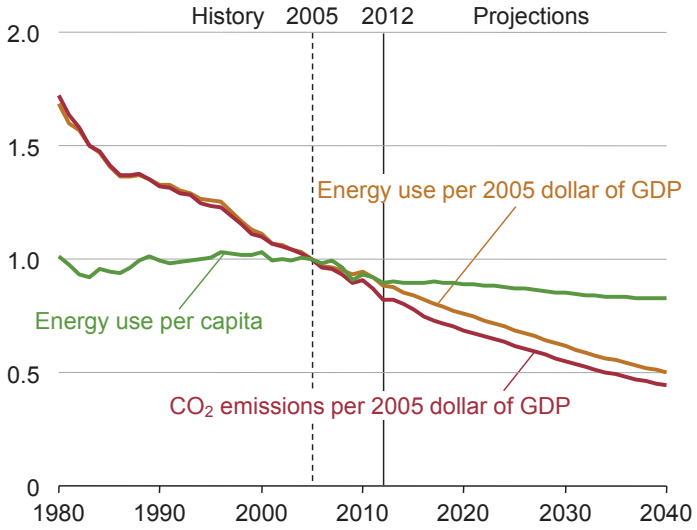
U.S. energy use per capita was fairly constant from 1990 to 2007 but began to fall after 2007. In the *AEO2014* Reference case, energy use per capita continues to decline as a result of improvements in energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 21% from 2012 to 2040, but energy use grows by only 12%, with energy use per capita declining by 8% from 2012 to 2040 (Figure 9).

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2014* Reference case, however, with lower-carbon fuels accounting for a growing share of total energy use, CO_2 emissions per dollar of GDP decline more rapidly than energy use per dollar of GDP, to 56% below their 2005 level in 2040 (or by 2.3% per year).

Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2014* Reference case (Figure 10). The decline in energy imports reflects increased domestic production of petroleum and natural gas, along with demand reductions resulting from rising energy prices and gradual improvement in vehicle efficiency. At the same time, natural gas exports increase (as domestic supplies increase and it becomes attractive to liquefy the natural gas for export), along with exports of motor gasoline (as demand declines and refiners are left with more than they can sell domestically) and exports of crude oil (as lighter domestic crude oil is swapped for the heavier crudes more commonly run in modern refineries). The net import share of total U.S. energy consumption is 4% in 2040, compared with 16% in 2012 and about 30% in 2005.

Figure 9. Energy use per capita, energy use per dollar of GDP, and emissions per dollar of GDP, 1980-2040 (index, 2005=1)



Petroleum and other liquids

U.S. production of crude oil (including lease condensate) in the *AEO2014* Reference case increases from 6.5 MMbbl/d in 2012 to 9.6 MMbbl/d in 2019, 22% higher than in *AEO2013* (Figure 11). Despite a decline after 2019, U.S. crude oil production remains at or above about 7.5 MMbbl/d through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very-low-permeability) formations. Offshore crude oil

Figure 10. Total energy production and consumption, 1980-2040 (quadrillion Btu)

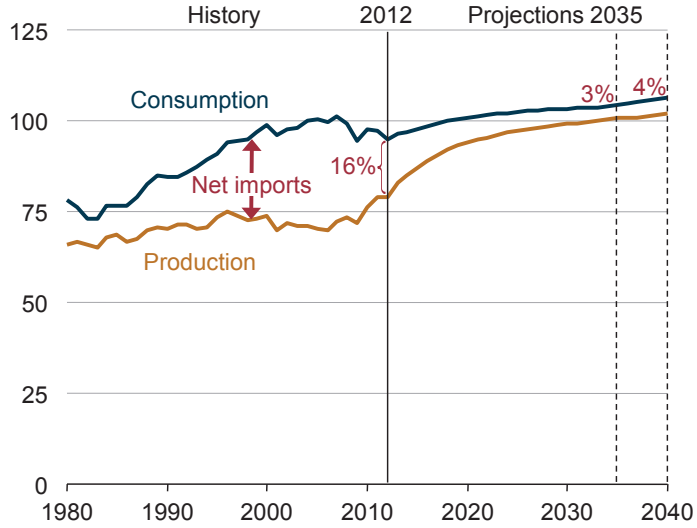
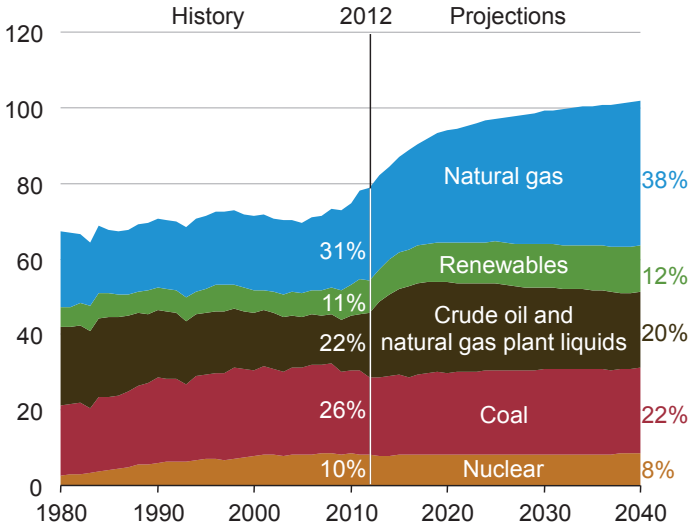


Figure 11. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)



provides a steady supply of domestic crude oil production, ranging between 1.6 and 2.0 MMbbl/d from 2015 through 2040, as the pace of development activity quickens and new, large development projects, predominantly in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in the *AEO2014* Reference case results in higher domestic crude oil production than in *AEO2013* throughout the projection. The pace of oil-directed drilling in the near term is much stronger than in *AEO2013*, as producers locate and target the sweet spots of plays currently under development and find additional tight formations that can be developed with the latest technologies. In the *AEO2014* Reference case, tight oil production increases from 2.3 MMbbl/d in 2012 (35% of total U.S. crude oil production) to 4.8 MMbbl/d in 2021 (51% of the total). As in *AEO2013*, tight oil production declines in *AEO2014* after 2021, as more development moves into less-productive areas.

U.S. use of imported petroleum and other liquid fuels continues to decline in *AEO2014* mainly as a result of increased domestic oil production. Imported petroleum and other liquid fuels as a share of total U.S. use reached 60% in 2005 before dipping below 50% in 2010 and falling further to 40% in 2012. The import share continues to decline to 25% in 2016 and then rises to about 32% in 2040 in the *AEO2014* reference case, as domestic production of tight oil begins to decline in 2022 (Figure 12).

Natural gas

Cumulative production of dry natural gas from 2012 to 2040 in the *AEO2014* Reference case is about 11% higher than in *AEO2013*, primarily reflecting continued growth in shale gas production resulting from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of NGL and crude oil, which in energy-equivalent terms have a higher value than dry natural gas. Cumulative production levels for tight gas and onshore associated-dissolved gas from oil formations exceed those in *AEO2013* through 2040 by 9% and 36%, respectively, making material contributions to the overall increase in production. Natural gas prices above $6/MMBtu toward the end of the projection period encourage drilling in less-productive but still-profitable areas in tight oil, shale oil, and natural gas formations. Lower 48 offshore natural gas production fluctuates between 1.7 Tcf and 2.9 Tcf per year, similar to the pattern in *AEO2013*. The multiyear decline in offshore natural gas production was reversed in 2012, with 15 new deepwater projects coming on line during the year.

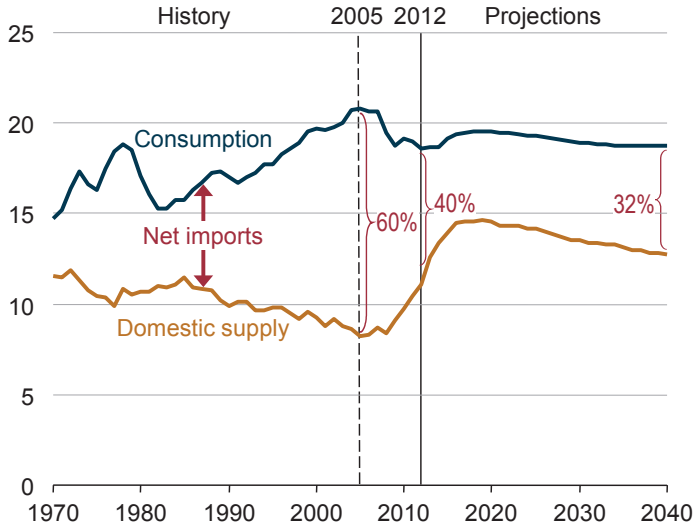
In the *AEO2014* Reference case, the United States becomes a net exporter of LNG in 2016, and it becomes an overall net exporter of natural gas in 2018, two years earlier than in *AEO2013*. U.S. exports of LNG from new liquefaction capacity are expected to surpass 2 Tcf by 2020 and increase to 3.5 Tcf in 2029. Net pipeline imports from Canada fall steadily until 2033, and then increase through 2040. Net pipeline exports to Mexico grow by more than 400% in the Reference case, with additional pipeline infrastructure added to enable the Mexican market to receive more pipeline natural gas from the United States.

U.S. cumulative net LNG exports from 2012 to 2040 are up by 160% in *AEO2014* compared with *AEO2013*, supported by increased use of LNG in markets outside America, strong domestic production, and low U.S. natural gas prices relative to other global markets.

Coal

Total U.S. coal production grows at an average rate of 0.3% per year in the *AEO2014* Reference case, from 20.6 quadrillion Btu (1,016 MMst) in 2012 to 22.6 quadrillion Btu (1,121 MMst) in 2040. U.S. electricity generation accounted for 91% of total U.S. coal consumption (in Btu) in 2012. Coal production declined by more than 7% in 2012, from 1,096 MMst in 2011, mostly in response to gas-on-coal competition. In the Reference case, production recovers to 1,062 MMst by 2015, in response to a rise in natural gas prices along with a moderate increase in electricity demand. A wave of coal-fired generating capacity retirements in response to MATS requirements coincides with a secondary drop in coal production to 1,022 MMst in 2016. Total production then increases gradually to 1,127 MMst in 2030 before stabilizing as a result of limits on achievable long-term capacity utilization rates for available coal units compared to *AEO2013*.

Figure 12. U.S. petroleum and other liquid fuels supply, 1970-2040 (million barrels per day)



Coal production from the Eastern Interior region in the *AEO2014* Reference case increases at a faster rate than projected in *AEO2013*, because of an improved productivity outlook, with 2020 production 27 MMst (18%) higher and 2040 production 58 MMst (34%) higher than projected in *AEO2013*. Lower overall coal consumption and improved competitiveness of coal produced in the Eastern Interior region compared to *AEO2013* lead to lower outlooks for Northern Appalachian and Powder River Basin coal production, as well as an accelerated decline in Central Appalachian production in *AEO2014*. As a result of changes to CTL cost assumptions, no CTL coal consumption or related production is projected in

AEO2014, compared with 0.3 quadrillion Btu in 2040 in *AEO2013*. Expectations for total U.S. coal exports in *AEO2014* are generally similar to those in *AEO2013*, with an increase from 126 MMst in 2012 to 161 MMst by 2040.

Electricity generation

Total electricity consumption in the *AEO2014* Reference case, including both purchases from electric power producers and on-site generation, grows from 3,826 billion kWh in 2012 to 4,954 billion kWh in 2040, an average annual rate of 0.9% that is about the same as in the *AEO2013* Reference case. While growth in electricity consumption is similar overall, growth in the industrial sector is much stronger than in *AEO2013*, while growth in the residential sector is weaker.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use. The *AEO2014* Reference case continues to assume implementation of the Clean Air Interstate Rule (CAIR)[30] as a result of an August 2012 federal court move to vacate the Cross-State Air Pollution Rule.[31] In addition, *AEO2014* continues to assume the implementation of MATS in 2016. Once MATS is in place, sulfur dioxide levels are reduced to well below the levels required by CAIR, and mercury emissions drop to 6.1 tons in 2016 from 30.8 tons in 2011 when the rule was finalized.

Coal-fired power generation over the next few years is slightly higher in *AEO2014* than in the *AEO2013* Reference case because of higher natural gas prices during that period, as well as pending nuclear retirements that necessitate additional baseload generation. After 2020, generation from coal flattens out and remains lower than projected in *AEO2013*, because more coal-fired capacity is retired and fewer new coal plants are built (Figure 13).

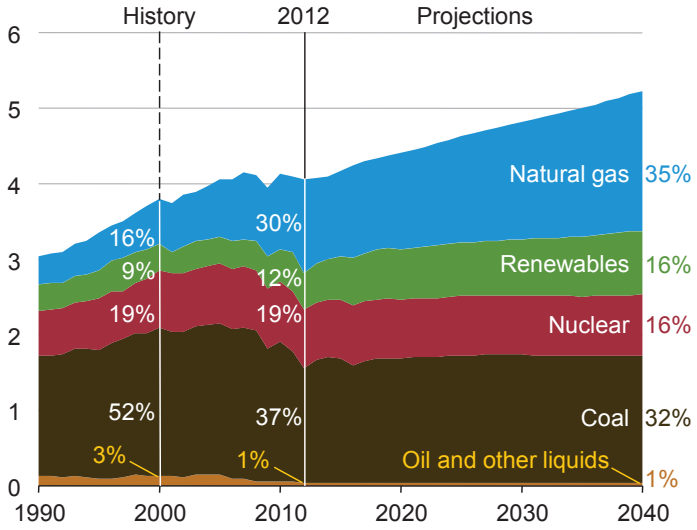
Coal-fired electricity generation has traditionally been the largest component of electricity generation, representing 37% of total generation in 2012. By 2035, however, natural gas generation is projected to surpass coal generation. Coal and natural gas each represent 34% of total generation in 2035, but by 2040 the coal share drops to 32%, and the natural gas share increases to 35%. Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the *AEO2014* Reference case, even with the assumption of current laws and policies. Low fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 310 gigawatts (GW) in 2012 to 262 GW in 2040 in the *AEO2014* Reference case. As with all projections, projected generation shares are highly sensitive to both fuel prices and changes in policies and regulations. Alternative cases in the full *AEO2014* will quantify these sensitivities.

In the first few years of the projection, electricity generation using natural gas is slightly lower in the *AEO2014* Reference case than in the *AEO2013* Reference case because of higher natural gas prices in *AEO2014*. By 2017, however, natural gas-fired generation is higher in *AEO2014* than in the *AEO2013* Reference case, and the difference continues to grow. Additional retirements of coal and nuclear plants result in the need for new capacity, and new natural gas-fired plants are much cheaper to build than coal, nuclear, or renewable plants. In 2020, natural gas-fired generation in *AEO2014* is 7% higher than in *AEO2013*, and in 2040 it is 16% higher.

Electricity generation from nuclear power plants grows by 5% in the *AEO2014* Reference case, from 769 billion kWh in 2012 to 811 billion kWh in 2040, accounting for about 16% of total generation in 2040 (compared with 19% in 2012). Nuclear generating capacity decreases from 102 GW in 2012 to 98 GW in 2020 as new construction (5.5 GW) and uprates at existing plants (0.7 GW) are more than offset by retirements in several regions where existing nuclear units are facing challenging economic conditions. After 2025, a small amount of new nuclear capacity comes on line as natural gas prices rise. In 2040, overall nuclear capacity is back up to 102 GW. *AEO2014* incorporates updated information from EIA data collections regarding planned nuclear plant construction and capacity uprates at existing units.

Increased generation with renewable energy, excluding hydropower, accounts for 28% of the overall growth in electricity generation from 2012 to 2040 in the *AEO2014* Reference case. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production processes. In the final decade of the projection, however, renewable generation growth is driven by increasing cost competiveness with other nonrenewable technologies.

Figure 13. Electricity generation by fuel, 1990-2040 (trillion kilowatthours)



[30]U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/.

[31]U.S. Environmental Protection Agency, "Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone" (Washington, DC: July 2011), http://www.epa.gov/airtransport/pdfs/CSAPRFactsheet.pdf.

Compared to the *AEO2013* Reference case, renewable generation is higher throughout most of the projection period, particularly in the near term, because of the inclusion of the energy provisions of the ATRA. This law, among other things, extends several tax credits for utility-scale renewables and redefines the qualification criteria, resulting in more construction of wind-powered generating capacity in the near term.

Reported renewable capacity already under construction has increased in recent years and is represented in *AEO2014*. Growth in renewable generation is supported by many state requirements, as well as regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 12% in 2012 to 16% in 2040 in the *AEO2014* Reference case, even with federal subsidies for renewable generation assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO_2 emissions

In the *AEO2014* Reference case, total U.S. energy-related CO_2 emissions in 2040 equal 5,599 million metric tons, 92 million metric tons (1.6%) lower than in *AEO2013*. However, the carbon intensity of the economy in 2040 is slightly (0.6%) higher in *AEO2014* as compared with *AEO2013*. Projected energy-related CO_2 emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level, compared to 9% and 5% below the 2005 level in *AEO2013*.

The lower GDP projection in *AEO2014* is partly the result of a lower population growth rate, and GDP per capita in 2040 is almost 4% higher in *AEO2014* than in *AEO2013*. Energy use per capita and energy-related CO_2 emissions per capita are higher in *AEO2014* than in *AEO2013* (about 5% in 2040). Also, higher levels of energy consumption and CO_2 emissions per dollar of GDP in *AEO2014* occur with a sectoral shift in the share of energy consumption from the residential, commercial, and transportation sectors toward the industrial sector, which generally is more energy- and carbon-intensive than other sectors of the economy. Over the projection period from 2012 to 2040, industrial emissions grow at an average annual rate of 0.6% in *AEO2014*, and industrial energy-related CO_2 emissions in 2040 are 133 million metric tons higher in *AEO2014* than in *AEO2013*.

When examining the electric power sector, excluding combined heat and power, there are offsetting factors in comparing *AEO2014* and *AEO2013*. Coal use for generation is 7.9% lower in 2040 (141 billion kWh) in *AEO2014* compared to *AEO2013* as a result of increased retirements of coal capacity and replacement with natural gas and renewables. However, nuclear generation, which has no CO_2 emissions, is also 10.1% (91 billion kWh) lower in 2040 in *AEO2014* compared to *AEO2013* because of more nuclear retirements in *AEO2014*. This offsets the CO_2 reduction achieved by switching from coal to natural gas and renewables. In total, the carbon intensity of the electric power sector is lower in *AEO2014* as generation declines by 0.2% (9 billion kWh), but emissions are 1.9% lower in 2040.

List of Acronyms

AEO	*Annual Energy Outlook*
AEO2013	*Annual Energy Outlook 2013*
AEO2014	*Annual Energy Outlook 2014*
ATRA	American Taxpayer Relief Act of 2012
bbl	Barrels
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DOE	U.S. Department of Energy
E85	Motor fuel containing up to 85% ethanol
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FFV	Flexible fuel vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquid
kWh	Kilowatthour
LDV	Light-duty vehicle
LED	Light emitting diode
LNG	Liquefied natural gas
LPG	Liquefied petroleum gases
LRG	Liquefied refinery gases
MATS	Mercury and Air Toxics Standards
MECS	Manufacturing Energy Consumption Survey
MMbbl/d	Million barrels per day
MMBtu	Million Btu
MMst	Million short tons
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PTC	Production tax credit
RECS	Residential Energy Consumption Survey
RFS	Renewable fuel standard
Tcf	Trillion cubic feet
VMT	Vehicle-miles traveled

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Primary energy production (quadrillion Btu)						
Crude oil and natural gas plant liquids	15.31	17.08	23.03	18.70	19.99	17.01
Dry natural gas	23.04	24.59	32.57	29.22	38.37	33.87
Coal	22.22	20.60	22.36	22.54	22.61	23.54
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	3.90	3.78	5.08	5.27	5.61	6.96
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.80	0.41	0.24	0.85	0.24	0.89
Total	**78.35**	**79.15**	**97.36**	**91.29**	**102.09**	**98.46**
Net imports (quadrillion Btu)						
Petroleum and other liquid fuels[a]	18.78	16.55	11.41	15.89	13.65	15.99
Natural gas (- indicates exports)	2.03	1.58	-3.41	-1.56	-5.81	-3.55
Coal/other (- indicates exports)	-2.32	-2.86	-3.16	-3.02	-3.69	-2.95
Total	**18.49**	**15.26**	**4.85**	**11.31**	**4.15**	**9.49**
Energy consumption by fuel (quadrillion Btu)						
Petroleum and other liquid fuels[a]	36.56	35.87	36.28	36.87	35.35	36.07
Natural gas	24.91	26.20	28.97	27.28	32.32	29.83
Coal	19.62	17.34	19.03	19.35	18.75	20.35
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	2.60	2.53	3.74	3.82	4.26	4.91
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.35	0.39	0.35	0.30	0.35	0.29
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Energy consumption by sector, including losses in electricity generation (quadrillion Btu)[b]						
Residential	21.39	20.10	20.58	21.08	21.48	23.08
Commercial	18.05	17.61	18.77	19.04	20.88	21.13
Industrial	30.46	30.54	37.43	35.46	38.33	36.16
Transportation	27.21	26.77	25.67	26.75	25.62	27.27
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Petroleum and other liquid fuels (million barrels per day)						
Domestic crude oil production	5.66	6.49	9.00	6.79	7.48	6.13
Other domestic production	4.71	4.60	5.14	5.63	5.22	5.83
Net imports	8.57	7.50	5.12	7.08	6.02	7.00
Consumption	18.92	18.49	19.27	19.50	18.73	18.95
Natural gas (trillion cubic feet)						
Dry gas production + supplemental gas	22.61	24.12	31.93	28.65	37.61	33.21
Net imports (- indicates exports)	1.96	1.51	-3.41	-1.58	-5.80	-3.55
Consumption	24.38	25.64	28.35	26.87	31.63	29.54

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040 (continued)

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Coal (million short tons)						
Production and waste coal	1,109	1,027	1,128	1,134	1,139	1,195
Net exports	96	118	135	124	160	123
Consumption	1,003	891	993	1,010	979	1,071
Prices (2012 dollars)						
Brent spot crude oil (dollars per barrel)	113.24	111.65	108.99	119.45	141.46	165.57
West Texas Intermediate spot crude oil (dollars per barrel)	96.55	94.12	106.99	117.41	139.46	163.54
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	5.23	4.96	7.65	7.97
Domestic coal at minemouth (dollars per short ton)	41.74	39.94	49.67	52.94	59.16	62.37
Average electricity price (cents per kilowatthour)	10.1	9.8	10.1	9.7	11.1	11.0
Economic indicators						
Real gross domestic product (billion 2005 dollars)	13,299	13,593	18,769	18,985	26,670	27,277
GDP chain-type price index (2005 = 1.000)	1.134	1.154	1.421	1.429	1.913	1.871
Real disposable personal income (billion 2005 dollars)	10,150	10,304	14,162	14,259	19,724	19,785
Value of industrial shipments (billion 2005 dollars)	5,926	6,147	8,778	8,548	10,994	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.30	6.99	5.46	5.39	3.99	3.95
Population (millions)	312.3	314.6	347.0	356.5	380.5	404.4
Energy-related carbon dioxide emissions (million metric tons)	**5,498**	**5,290**	**5,526**	**5,501**	**5,599**	**5,691**

[a]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
[b]Electric power sector consumption is distributed to the end-use sectors.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2014 National Energy Modeling System, run REF2014.D102413A; and AEO2013 National Energy Modeling System, run REF2013.D102312A.

RECEIVED
By Docket Room at 11:26 am, Jan 14, 2013

From: Tyner, Wallace E.
To: LNGStudy
Subject: 2012 LNG Export Study
Date: Monday, January 14, 2013 11:25:34 AM
Attachments: Comparison of Analysis of Natural Gas Export Impacts w exec sum Jan rev.pdf

---

Comments attached.

Wallace E. Tyner
James and Lois Ackerman Professor
Department of Agricultural Economics
Purdue University
403 West State Street
West Lafayette, IN 47907-2056
765-494-0199
fax 765-494-9176
http://www.agecon.purdue.edu

Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University

Wallace E. Tyner, James and Lois Ackerman Professor
Kemal Sarica, Post-doctoral Associate
Purdue University

Executive Summary

The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. There are two economic studies of the impacts on the U.S. economy of increased natural gas exports – one done for DOE by NERA Economic Consultants and the other by Tyner and Sarica of Purdue University. The NERA study results in a very small income gain for the U.S. from increased natural gas exports, and the Purdue study results in a small economic loss.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners? In addition, while U.S. industry and consumers would face higher natural gas and electricity prices, foreign competitors would face lower energy costs with increased U.S. natural gas exports.

Beyond the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more informed debate on this critically important national policy issue.

Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University

Wallace E. Tyner, James and Lois Ackerman Professor
Kemal Sarica, Post-doctoral Associate
Purdue University

The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. Exports would be economically attractive because there is a very large price gap at present between US natural gas price (around $3.50/MCF) and prices in foreign markets, which can range up to $15/MCF. On the other side, there is potentially large domestic demand for natural gas in electricity generation, industrial applications, the transportation sector, and for other uses. There is no doubt that exporting a large amount of natural gas would increase the domestic natural gas price for all these potential uses. Higher natural gas prices would, in turn, mean higher electricity prices, so the higher energy costs would go beyond just natural gas users. These higher energy costs would also lead to contraction in energy intensive sectors relative to the reference case with small natural gas exports.

NERA Economic Consulting study

In December 2012, DOE released a commissioned study done by NERA Economic Consultants, a private consulting firm[1]. They used their own proprietary energy-economy model named NewERA for the analysis. Their results suggest that the US achieves economic gains from natural gas exports and that the gains increase as the level of natural gas exports grows. Their result is the classical economic result that free trade provides net gains to the economy under most conditions. While economic theory does not suggest that free trade always produces economic gains for all parties under all conditions, the general argument is that under a wide range of conditions, free trade does provide net benefits with some winners and some losers. The NERA results do show higher natural gas prices due to exports with the magnitude of the increase depending on domestic and global supply and demand factors. The NERA study used input data and information from a companion study done by the Energy information Agency in DOE [2], which estimated the impacts of export levels on US natural gas prices.

The NERA analysis focused on export levels of 6 and 12 BCF per day, but there were many other scenarios and sensitivity analyses. In general, the welfare or net income increases estimated in the NERA scenarios were very small, generally ranging from 0.01 to 0.025 percent over the reference case. There were considerable losses in capital and wage income in sectors affected by the higher natural gas prices, and

income gains to natural gas resource owners through export earnings and wealth transfers to resource owners. By 2030 the total net increase in GDP amounted to about $10 billion 2010$, which could be perceived as being quite small in a $15 trillion economy [3]. Wage income falls in agriculture, energy intensive sectors, and the electricity sector. The percentage declines in wages in these sectors were generally much greater than the percentage increases in net national income. Natural gas price increases did not exceed 20 percent in any of the simulations. The NewERA energy-economy model takes inputs from the EIA NEMS natural gas projections [2] and from a global natural gas model.

Purdue MARKAL-Macro Analysis

The Purdue approach was to use a well-established bottom-up energy model named MARKAL (MARKet ALlocation). Bottom-up means that the model is built upon thousands of current and future prospective energy technologies and resources. These energy resources supply projected energy service demands for the various sectors of the economy. In addition to the standard MARKAL model, we also have adapted a version of the MARKAL-Macro model which permits us to include feedbacks between energy prices and economic activity. Thus the GDP effects of alternative energy policies are captured as well as technology and supply impacts. For these reasons, MARKAL-Macro is an ideal tool for this kind of analysis. The Purdue analysis was done for the two levels from the EIA and NERA reports (6 BCF/day and 12 BCF/day plus 18 BCF per day). The EIA NEMS model is a bottom-up model somewhat similar to MARKAL. Details of the analysis are available in Sarica and Tyner [4].

The Purdue analysis shows that increasing natural gas exports actually results in a slight decline in GDP. Essentially the gains from exports are less than the losses in electricity and energy intensive sectors in the economy. The GDP losses are around 0.04%, 0.11%, and 0.17% for the 6, 12, and 18 BCF/day cases respectively for the year 2035.

The general trends in the change in energy resource mix for 2035 are as follows: 1)the domestic energy share for natural gas falls from 25 to 22 percent) as exports of natural gas increase; 2)domestic use of coal increases from 21 to 23 percent as natural gas exports increase; 3)the fraction of oil in total consumption increases from 36 to 37 percent; 4)there are small increases in nuclear and renewables (hydro, solar, wind, and biomass).

The impacts on the electricity sector come in higher electricity prices and higher GHG emissions. In 2035, electricity price is up compared with the reference case by 1.1%, 4.3%, and 7.2% for the 6 BCF, 12 BCF, and 18 BCF cases respectively. Of course, these higher electricity prices are passed through the entire economy through industrial, commercial, and residential sectors. Electricity GHG emissions in the early years of the simulation horizon are around 2% higher for the 6 BCF case, and 7-12% higher for the 12 and 18 BCF cases.

In 2035, CNG use in transportation for the reference case is 1.3 bil. gal. gasoline equivalent, but it drops to 0.2-0.3 in the three export cases. CNG use in heavy duty vehicles disappears in the 12 BCF case, and CNG use in most of the vehicle categories drops considerably. The bottom line is that while CNG use in transport is not large even in the reference case, it plummets in the export cases.

We examined impacts on the metals, non-metals, paper, and chemical sectors. Total energy use and thus also economic output declines from 1 to 4 percent in all the energy intensive sectors depending on the sector and the level of natural gas exports. Thus, it is easy to see how the Purdue results show a decline in GDP since there are declines in several key sectors in the economy driven by the higher natural gas prices.

Comparison

These studies use different models, somewhat different data sets, and different modeling parameters. The results are different, but there are some important similarities. On GDP impacts, the sign of the change is different. NERA gets a very small but positive welfare impact, and Purdue MARKAL-Macro gets a small negative impact. Our view is that because the net income impacts are so small, it is not appropriate to place much emphasis on that outcome. What is important is to explain the differences and to understand the drivers of the differences.

Purdue MARKAL-Macro gets larger natural gas price increases, which, in-turn leads to electricity price increases and to declines in energy use and output for key energy intensive sectors. The decline in economic activity of these sectors is a key driver in the decline in GDP. In fact, since neither the Purdue nor the NERA model are complete global CGE models, the estimated decline in economic activity of these sectors is probably an underestimate because all these sectors would face higher costs and would be less competitive on the global market with higher natural gas exports. In other words, U.S, economic losses likely would be larger than estimated by either model. Also, other nations would face lower energy costs with our LNG exports.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners?

In addition to the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort

of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

Conclusions

Beyond the analysis conducted here, it is important to note that neither the model used in this analysis nor the NERA model are global in scope. Thus, neither includes the trade impacts of US natural gas exports. However, we can describe those impacts qualitatively. Increased US natural gas exports will reduce energy costs for industry and consumers in foreign countries and increase those costs for the US. Thus, US industry will be rendered less competitive compared with foreign industry. This loss of export revenue would be in addition to the GDP loss estimated in this analysis. Moreover, US consumers lose due to higher energy prices, and foreign consumers gain.

Given all the results of this analysis, it is clear that policy makers need to be very careful in approving US natural gas exports. While we are normally disciples of the free trade orthodoxy, one must examine the evidence in each case. We have done that, and the analysis shows that this case is different. Using the natural gas in the US is more advantageous than exports, both economically and environmentally.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more research and informed debate on this critically important national policy issue.

References

1. NERA Economic Consulting. Macroeconomic Impacts of LNG Exports from the United States. Washington, D.C.: 2012 2012. Report No.
2. Energy Information Administration. Effect of Increased Natural Gas Exports on Domestic Energy Markets. Washington, D.C.January 2012.
3. Trading Economics. 2012. Available from: http://www.tradingeconomics.com/united-states/gdp.
4. Sarica K, Tyner WE. Economic and Environmental Impacts of Increased US Exports of Natural Gas. Energy Policy. 2013;under review.

July 15, 2013

Via email (deq.publicnotices@la.gov)
Fax (225-219-3309) & U.S. Mail
Louisiana Department of Environmental Quality
Public Participation Group
P.O. Box 4313
Baton Rouge, LA 70821-4313

RE: Comments on the Proposed Part 70 Operating Permit Renewal/Modification and Prevention of Significant Deterioration Permit for the Cameron LNG, LLC Terminal in Cameron Parish, Louisiana
AI No. 99407
Permit No. 0560-00184-V5, Activity No. PER20120001
Permit No. PSD-LA-766, Activity No. PER20120002

Sierra Club, RESTORE, and Michael Tritico (collectively, "Sierra Club" or "Commenters") write to comment on the Part 70 operating permit renewal/modification and prevention of significant deterioration ("PSD") permit proposed by the Louisiana Department of Environmental Quality ("LDEQ") for the addition of natural gas liquefaction facilities and related equipment at an existing liquefied natural gas ("LNG") import terminal by Cameron LNG, LLC ("Cameron"), in Cameron Parish, Louisiana. Commenters submit these comments to protect their interests and the interests of their members who will be affected by the facility.

Sierra Club is a national grassroots environmental organization founded in 1892. Its mission is to explore, enjoy, and protect the planet. Sierra Club currently has nearly 600,000 members nationwide, including nearly 2,800 members in Louisiana.

Restore Explicit Symmetry To Our Ravaged Earth ("RESTORE"), founded in 1974, is the oldest environmental group in southwest Louisiana. Its mission is to restore the environment to its natural state.

Michael Tritico is a resident of Longville, Louisiana who is concerned that the Cameron facility, like other proposed LNG projects in the area, would impose public safety hazards, ecosystem disruptions, and economic distortions, among other things, on the local community.

I. Introduction

This permit arises from Cameron's proposal to add liquefaction and export capabilities to an existing LNG import terminal. The proposed equipment includes six refrigeration compressor turbines, flares, emergency generators, water pumps, and associated equipment. Cameron's proposal would revive a terminal that is not currently in heavy use, substantially increasing terminal emissions and emissions related to increased vessel traffic. If constructed, the proposed terminal would emit 3,947.27 tons of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and volatile organic compounds per year, and would emit almost four million tons per year of carbon dioxide equivalent in greenhouse gases.[1] The terminal would also emit 26.172 tons per year of toxic air pollution.[2] Even greater quantities of additional pollution would result from the new production the proposal would induce in the gasfields that would supply the gas for export.

Cameron applied for the requested permit on August 16, 2012 and supplemented its application five times, most recently on April 30, 2013. LDEQ issued public notice of a draft permit on June 6, 2013. LDEQ has requested public comment on the application and draft permit by July 15, 2013.

Commenters submit the following comments and object to the draft permit. As we explain below, the proposed permit violates the requirements of the Clean Air Act and Louisiana law because, among other things: (a) Cameron has not provided, and thus LDEQ has not considered, adequate information to determine that adverse environmental impacts have been minimized or avoided as much as possible, as required under the Louisiana Constitution; (b) neither Cameron nor LDEQ has adequately analyzed growth in gasfield development associated with the proposed facilities; (c) the facility will not comply with applicable ozone standards, and in fact will cause or contribute to exceedances of these standards; and (d) the proposed permit fails to require the best available control technology ("BACT") for numerous emission units.

II. Neither Cameron Nor LDEQ Has Demonstrated That Adverse Environmental Impacts Have Been Adequately Mitigated or Avoided

A. Introduction

The Louisiana Constitution mandates that "[t]he natural resources of the state, including air and water, and the healthful, scenic, historic, and esthetic quality of the environment

[1] Draft PSD Permit No. PSD-LA-766 [hereinafter "Draft PSD Permit"], Preliminary Determination Summary, at ¶ III.

[2] Draft Title V Permit No. 0560-00184-V5, Briefing Sheet, at ¶ 3. The figure that sums criteria pollutants was calculated by adding the "after" column in the table provided in that paragraph.

shall be protected, conserved, and replenished insofar as possible and consistent with the health, safety, and welfare of the people." La. Const. art. IX, § 1. The Louisiana Supreme Court has interpreted this constitutional mandate to require that, before granting approval of any proposed action affecting the environment, Louisiana agencies demonstrate that adverse environmental impacts have been minimized or avoided as much as possible, consistent with the public welfare. *Save Ourselves, Inc. v. La. Envtl. Control Comm'n*, 452 So. 2d 1152, 1157 (La. 1984).

Specifically, to fulfill its public trustee duty, LDEQ's decision must demonstrate that:

(1) the potential and real adverse environmental effects of the proposed project have been avoided to the maximum extent possible;

(2) a cost-benefit analysis of the environmental impact costs balanced against the social and economic benefits of the project demonstrate that the latter outweighs the former; and

(3) there are no alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits to the extent applicable.

See In re Oil & Gas Exploration, Development, & Production Facilities Permit, 70 So. 3d 101, 104 (La. App. 2011); *In re Rubicon, Inc*., 670 So. 2d 475, 483 (La. App. 1996) (citing *Save Ourselves*, 452 So. 2d 1152).

Furthermore, as a public trustee, LDEQ "is duty-bound to demonstrate that it has properly exercised the discretion vested in it by making basic findings supported by evidence and ultimate findings that flow rationally from the basic findings; and it must articulate a rational connection between the facts found and the order, or in this case, the permit issued." *In re Oil & Gas Permit*, 70 So. 3d at 102 (citing *Save Ourselves*, 452 So. 2d at 1159-60).

In this case, Cameron's Environmental Impact Analysis/Environmental Assessment Statement ("EAS")[3] fails to provide, and LDEQ did not consider, information adequate to fulfill LDEQ's public trustee duty under article IX, § 1 of the Louisiana Constitution. LDEQ cannot issue a valid permit without a record that allows it to perform this duty. Consequently, the Sierra Club urges LDEQ to deny Cameron's permit application. LDEQ must require Cameron to correct its application and include facts necessary for an adequate evaluation.

[3] Commenters assume that Cameron's narrative Environmental Impact Analysis, the most recent version of which was provided in Cameron's April 30, 2013 supplement to its application, is intended to serve as the "Environmental Assessment Statement" referenced in Cameron's public notice. Throughout this comment, we refer to this April 30, 2013 document as "EAS."

B. The EAS Fails to Account for Emissions Associated With the Revival of a Moribund Import Terminal

The EAS and the rest of Cameron's permit file fail generally to acknowledge, grapple with, or attempt to mitigate the many environmental impacts likely to be associated with the revival of an LNG terminal that has essentially fallen out of use.[4] The EAS states repeatedly that the liquefaction facilities will be constructed adjacent to the existing site,[5] minimizing impacts, and that the new facilities will not require a change in the size or quantity of ships currently authorized for the terminal.[6] By framing the proposed project's impacts as incremental to the impacts that are already permitted for the import terminal, the EAS ignores the reality that the terminal has fallen into disuse, and is currently generating very little air and water pollution, noise, and ship and truck traffic. The proposed project would bring the terminal back to life from a baseline of almost zero impacts. Accordingly, Cameron must provide, and LDEQ must analyze, information related to *all* of the project impacts, using current facility operations, rather than permitted conditions, as a baseline. LDEQ must comply with its public trustee obligations with respect to all of these project impacts.

C. The EAS Fails to Adequately Analyze and Minimize Transportation Impacts

The EAS states: "No transportation problems are anticipated to be associated with the Liquefaction Project. Construction materials and process equipment will be delivered via barges or trucks utilizing existing roads. Deliveries will be scheduled during off-peak traffic hours whenever possible."[7] Cameron provides no support for its statement that transportation problems cannot be anticipated; it admits that equipment will be delivered using existing roads, and mentions only a single means of controlling traffic: scheduling deliveries during off-peak hours when "possible."[8] Later, the EAS mentions that "studies have been conducted to determine the potential effects of increases in traffic,"[9] but the EAS does not summarize or incorporate these studies or explain how, in light of the increases shown by the studies and the scant mitigation mentioned, transportation impacts are adequately mitigated. Moreover, in the EAS, Cameron does not attempt to quantify the traffic likely to occur or demonstrate that local communities will not be negatively

---

[4] According to the Maritime Administration of the U.S. Department of Transportation, in 2011 there were only six calls by vessels of *any* type at the Cameron terminal, despite its capacity for hundreds of thousands of calls. United States Department of Transportation, Maritime Administration, "Vessels Calls at U.S. Ports by Vessel Type," at http://www.marad.dot.gov/library_landing_page/data_and_statistics/Data_and_Statistics.htm (under HTML heading "Vessel Calls") (last updated Mar. 28, 2013).

[5] *E.g.*, Environmental Impact Assessment ("EAS"), provided in April 30, 2013 supplemental materials, at 1, 8.

[6] EAS at 1.

[7] EAS at 2.

[8] EAS at 2.

[9] EAS at 7.

affected by traffic when a terminal that is currently barely in use roars to life again. Cameron also fails to show that available measures to avoid and minimize traffic impacts are actually being implemented, stating only that they will be implemented when possible. LDEQ must require Cameron to provide this additional information, and must update its analysis to provide a reasoned basis for the conclusion that transportation impacts are being avoided to the maximum extent possible.

D. The EAS Fails to Adequately Analyze Chemical Release Issues

The EAS provides only a conclusory discussion of the possibility for a dangerous chemical release. This discussion does not provide an adequate basis for LDEQ to conclude that chemical release problems have been minimized and avoided to the maximum extent possible.

The EAS states: "[t]he Liquefaction Project is designed to meet or exceed all existing environmental regulations in a manner that minimizes the potential for accidental releases. Adverse environmental impacts and accidental releases will be avoided to the maximum extent possible. This facility is being designed to contain all potential liquid release scenarios and minimize offsite consequences."[10] Cameron then goes on to state that the proposed facility "has highly trained and dedicated staff to operate the terminal," and that this staff "will be thoroughly trained" and "familiar with the potential hazards of operating the Cameron Liquefaction facility."[11] Cameron then states that "[t]he combination of properly designed facilities and thoroughly trained personnel accomplishes the goal of minimizing the potential for accidental releases."[12] Cameron later mentions that "[e]xisting SPCC and stormwater pollution prevention plans will be modified" to include the proposed facilities."[13]

Cameron provides no support for its conclusion that its proposal minimizes and avoids hazardous release risk. For example, there is no basis to conclude that the proposed facility "has highly trained and dedicated staff;" the facility has not even been constructed yet, and Cameron makes no attempt to detail staff safety credentials or provide any basis for its conclusion for its conclusion that staff is or will be highly trained. Cameron also makes no attempt to show that its facilities are "properly designed" to handle releases, and it states that it will employ unspecified best management practices and perhaps follow as-yet-unwritten pollution prevention plans to manage spill risks. These unsupported statements provide no basis for the conclusion that chemical release hazards have been adequately avoided or minimized. LDEQ must require Cameron to provide additional information so that it may make a reasoned determination whether the risks associated with hazardous release have been adequately minimized.

---

[10] EAS at 3.
[11] EAS at 3.
[12] EAS at 3.
[13] EAS at 5.

E. The EAS Fails to Evaluate Air Pollution Associated With the Proposed Facility and With Associated Increases in Natural Gas Production

As explained fully in section III.A below, Cameron has not provided, and LDEQ thus has not considered, information related to the extensive air pollution that would result from new gas drilling necessary to supply the proposed project. For this and other reasons, Cameron's EAS dramatically understates the air pollution that is likely to result from the proposed project. The EAS states, for example, that "[t]he potential impacts from air emissions from the Liquefaction Project are minimal and will not cause any significant adverse impacts."[14] This statement, and the EAS's general conclusion that the proposed facility's environmental effects have been minimized and avoided to the maximum extent possible, is undermined by the substantial air pollution that would be generated by increased upstream drilling. Neither Cameron nor LDEQ has analyzed, or attempted to minimize or avoid, these impacts. LDEQ must require Cameron to provide this additional information so that it may make a reasoned determination whether environmental impacts associated with increased gas production, as well as the ozone impacts of the proposed facility, have been adequately minimized and avoided.

Likewise, as explained fully in section III.B, the proposed permits do not adequately account for the impacts of the proposed project on ozone. LDEQ must require Cameron to submit the additional analysis described in section III.B, and must ensure that all of the impacts described in that section are fully accounted for an appropriately minimized and avoided.

F. The EAS Fails to Adequately Evaluate Pollution Control Technologies

The EAS states, without analysis, that "no other alternative would be more protective of the environment without unduly curtailing non-environmental benefits."[15] In section IV below, however, the Sierra Club outlines numerous alternative pollution control strategies that would reduce air pollution from the project, including electrically driven compression, selective catalytic reduction ("SCR"), and controls on fugitive emissions. LDEQ must request additional information from Cameron, as outlined in section IV, so that it can comply with its public trustee obligation to account for all of the proposed facility's pollution and ensure that pollution is adequately minimized and avoided.

III. The Proposed Facility Will Cause or Contribute to Violation of Air Quality Standards

The Clean Air Act prohibits issuance of a PSD permit unless the applicant demonstrates "that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" any "national ambient air quality standard

[14] EAS at 4.
[15] EAS at 7.

[NAAQS] in any air quality control region." 42 U.S.C. § 7475(a)(3). The analysis satisfying this requirement must include "secondary emissions" that are associated with the proposed facility. 40 C.F.R. § 52.21(k); LAC 33:III:509.K. Secondary emissions are defined as "emissions that would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself." 40 C.F.R. § 52.21(b)(18); LAC 33:III:509.B.

The Act also requires that a PSD applicant provide "an analysis of any air quality impacts projected for the area as a result of growth associated with [the] facility." 42 U.S.C. § 7475(a)(6); *see also* 40 C.F.R. § 52.21(o)(2) (""The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification."); LAC 33:III.509.O.2 (same).[16]

Thus, under both state and federal law, the PSD permit cannot issue, and construction cannot begin, unless and until LDEQ determines that the LNG facility will not contribute to a violation of any NAAQS and will therefore comply with the SIP provision requiring NAAQS compliance. Appropriate analysis of secondary emissions and air quality impacts caused by associated growth is also required.

Cameron has failed to show that the proposed project will not cause or contribute to violations of the NAAQS. First, Cameron has not provided the required analysis of secondary and growth-related emissions that would be caused by the proposed facility. Second, the proposed project will increase ambient ozone concentrations by emitting NO_x and VOC, both ozone precursors, but Cameron's application does not include an adequate analysis of these ozone impacts.

A. Cameron Has Not Provided Analysis of the Air Impacts of Growth in Gas Production

The draft permit and permit application improperly fail to consider the impacts of increased gas production that will result from the proposed project.

1. Increased Gas Production Must Be Analyzed as a Secondary Emission

As mentioned, federal and state law require that secondary emissions that "would occur as the result of the construction or operation of a major stationary source, but do not come from the major stationary source or major modification itself" be incorporated into the source impact analysis aimed at demonstrating that the source will not cause or

[16] *See also* LDEQ Air Quality Modeling Procedures (Aug. 2006), *available at* http://www.deq.louisiana.gov/portal/Portals/0/permits/air/Air%20Quality%20Modeling%20Procedures.pdf.

contribute to NAAQS violations. LAC 33:III:509.B; 40 C.F.R. § 52.21(b)(18); *see also* 40 C.F.R. § 52.21(k); LAC 33:III:509.K. Under the Louisiana SIP, secondary emissions "must be specific, well defined, and quantifiable, and impact the same general areas as the stationary source modification that causes the secondary emissions." LAC 33:III:509.B.

Emissions from the new gas production that will result from the construction and operation of the proposed facility satisfy the definition of secondary emissions and thus should have been incorporated into the analysis provided by Cameron. First, it is clear that new gas production will occur "as the result of the construction or operation" of the proposed facility. In filings before DOE and FERC, Cameron has explicitly stated that new production will occur, and has in fact claimed that the economic benefits that its project will generate flow largely from increased production.[17] The connection Cameron has made between its proposed facility and increased gas production is consistent with broader estimates of the natural gas supply response to LNG export; the Energy Information Administration (EIA) recently concluded that 60 to 70% of gas exported as LNG will be sourced from increases in domestic gas production, primarily from shale gas, specifically predicting 63% of exports to come from new production in EIA's reference case.[18] EIA's National Energy Modeling System, which underlies EIA's general report on exports, provides a tool that can be used to precisely predict how production would increase in response to Cameron's project in particular. [19] The National Energy Modeling System and similar private models also provide the ability to predict with precision how particular plays will respond to exports from particular locations. Increased gas production resulting from the construction and operation of Cameron's proposed facility is therefore "well defined and quantifiable" within the meaning of the Louisiana SIP's definition.

---

[17] *See, e.g.*, Application of Cameron LNG, LLC for Authorization Under Section 3 of the Natural Gas Act, FERC Dkt. No. CP13-25 (Dec. 7, 2012), at 16; *id*. at Ex. Z-1 p. 6, *available at* http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14072973; *see also* Cameron LNG, LLC Application for Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free-Trade-Agreement Countries, DOE/FE Dkt. No. 11-162-LNG, at App'x C, Black and Veatch Report at 8, *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/Cameron_11-162-LNG_NFTA.html.

[18] Energy Information Administration, *Effects of Increased Natural Gas Exports on Domestic Energy Markets*, 6, 11 (January 2012), *available at* http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf.

[19] *See, e.g.*, EIA, *The National Energy Modeling System: An Overview* (2009). NEMS and similar tools are described in detail in the Sierra Club's motion to intervene, protest, and comments in the FERC licensing proceeding for the Cameron facility, *available at* http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14082625.

This additional gas production will have significant, quantifiable air emissions, including emissions of ozone precursors NO_x and VOC.[20] At a minimum, these emissions can be quantified through the use of existing EPA conversion factors that allow for estimates of the air impacts of gas production. EPA's current greenhouse gas inventory implies that about 1.5% of gross gas production leaks to the atmosphere in one way or another.[21] EPA's inventory provides a floor on possible leak rates, but there is reason to suspect that gas production emissions are even higher. Whereas EPA's estimates are based on industry-reported data regarding assumed emission factors, recent studies measuring emissions directly suggests that leaks may actually occur at rates between 4.8% and 9%, at least in some fields.[22] These leak rates, and EPA conversion factors between the typical volumes of methane, VOC, and other pollutants in natural gas,[23] make it possible to calculate the potential impact of increasing gas production in the way that LNG export would require.

The table below uses these conversion factors to generate a rough, preliminary calculation of the emissions associated with exporting 620 Bcf/year of gas,[24] as Cameron

---

[20] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules, 4-7, 5-6, 6-5, 7-9, 8-1 (July 2011).

[21] EPA's 2013 inventory does not explicitly state the leak rate for natural gas production. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2011, Table ES-2 (2013), attached as Exhibit 62. EPA's prior inventory implied a leak rate of 2.4%, as extrapolated by a previous study. Alvarez *et al.*, *Greater focus needed on methane leakage from natural gas infrastructure*, Proceedings of the National Academy of Science (Apr. 2012) at 1. Because the current inventory's sector-wide emissions estimates for the same time periods have been reduced by roughly 1/3, the current inventory implies a leak rate of roughly 1.5%.

[22] *See* G. Petron et al, *Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study*, 117 J. of Geophysical Research 4304, DOI 10.1029/2011JD016360 (2012); Tollefson, *Methane leaks erode green credentials of natural gas*, Nature (2013).

[23] *See* EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules at t.4.2 (July 2011). EPA calculated average composition factors for gas from well completions. These estimates, which are based on a range of national data, are robust, though they could be better tailored for particular fields and points along the line from wellhead to LNG terminal. Nonetheless, they demonstrate that quantitative estimates of gasfield emissions are feasible. Among others, EPA's conversion factors are: 0.0208 tons of methane per mcf of gas and 0.1459 lb VOC per lb methane.

[24] *See* Cameron LNG, LLC Application for Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free-Trade-Agreement Countries, DOE/FE Dkt. No. 11-162-LNG, at 1, *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/Cameron_11-162-LNG_NFTA.html.

proposes to do. The table assumes, based on EIA estimates and estimates submitted by other export applicants,[25] that 63% of gas exported by Cameron will come from new production, and that Cameron's proposal will thus induce 390.6 Bcf/year of additional production. We calculate for a 1% leak rate (which is below the current value, but is included as a conservative case to reflect successful air pollution controls more extensive than those which have so far been required), the current EPA estimated rate of 1.5%, and the higher leak rates the NOAA studies suggest, generating results for methane and VOC.[26]

Table 1. Emissions Associated with Producing 390.6 Bcf/year of Natural Gas

Leak Rate	**Methane (tpy)**	**VOC (tpy)**
1%	81,245	11,854
1.5%	121,868	17,781
4.8%	389,975	56,897
9%	731,203	106,683

In summary, there can be no debate that increased gasfield emissions "would occur as the result of the construction or operation of a major stationary source." As demonstrated, these emissions are well defined and quantifiable, as required by the Louisiana SIP definition of secondary emissions. Accordingly, LDEQ and Cameron can and must incorporate these emissions into the required analysis demonstrating that the proposed facility will not cause or contribute to NAAQS violations.

2. Emissions From Increased Gas Production Must Be Analyzed as Air Quality Impacts Resulting From Growth Associated With the Facility

Even if induced production emissions did not qualify as secondary emissions that must be analyzed as described above, Cameron and LDEQ would still be required to analyze these emissions' impacts because they result from growth associated with the proposed facility. As noted above, the Clean Air Act and Louisiana's SIP require "an analysis of

[25] *See* Golden Pass DOE/FE Application, DOE/FE Dkt. No. 12-156-LNG, at Deloitte Report at 15, *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/Golden_Pass_Products,_LLC_12-156-LNG.html.

[26] These figures were calculated by converting the volume of gas to be exported (in bcf) to mcf, and then multiplying by 63% to generate new production volumes. The new production volumes of gas were, in turn, multiplied by the relevant EPA conversion factors to generate tonnages of the relevant pollutants. These results are approximations; although we reported the arithmetic results of this calculation, of course only the first few significant figures of each value should be the focus.

any air quality impacts projected for the area as a result of growth associated with [the] facility." 42 U.S.C. § 7475(a)(6); *see also* 40 C.F.R. § 52.21(o)(2), LAC 33:III.509.O.2. According to EPA's NSR Workshop Manual, "growth" includes industrial growth, defined as "growth in those industries providing goods and services, maintenance facilities, and other large industries necessary for the operation of the source or modification under review."[27]

As explained above, Cameron has been forthright, in its filings before DOE and FERC, about the growth its proposal will induce in natural gas production. This increased gas production is plainly growth in an "industr[y] providing goods and services" for the facility; natural gas is an essential input for the production of LNG. Moreover, increased gas production is "necessary for the operation of the source;" as explained above, Cameron's own filings, as well as EIA predictions applicable to the entire industry, indicate that increased gas production will be necessary if natural gas export is to occur on the scale proposed.

The analysis summarized in Table 1, above, also makes clear that significant air quality impacts will result from increased gas production induced by Cameron's proposal. This is apparent from the sheer quantity of the emissions induced; for example, even if the lowest leak rates are assumed, the VOC emissions associated with induced gas production will be hundreds of times greater than new VOC emissions from the proposed facility itself (124.57 tons per year, according to the preliminary determination summary in the draft PSD permit). Experience in other states also teaches that air quality impacts from natural gas production can be severe. As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas-Fort Worth area in Texas is home to substantial oil and gas development.[28] Of the nine counties surrounding the Dallas-Fort Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[29] A 2009 study found that summertime emissions of smog-forming pollutants from these counties were roughly comparable to emissions from motor vehicles in those areas.[30]

Accordingly, by ignoring additional emissions caused by the new gas production that would be needed to supply Cameron's proposed facility, LDEQ is ignoring potentially severe air quality impacts. These impacts are potentially even more significant in light of

---

[27] Draft EPA NRS Workshop Manual [hereinafter "NSR Manual"] at D.3, *available at* http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.
[28] *See generally* Texas Railroad Commission, Barnett Shale Information, http://www.rrc.state.tx.us/barnettshale/index.php (last visited July 11, 2013).
[29] Al Armendariz, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements (Jan. 26, 2009), at 1, 3, *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf.
[30] *Id.* at 1, 25-26.

the cumulative impacts of several other export proposals in the surrounding area, which, together, would result in a significant increase in gas production and concomitant air pollution impacts. LDEQ must require Cameron to provide additional analysis of the air quality impacts resulting from increased gasfield emissions. As explained, new gasfield emissions are both secondary and growth emissions under state and federal law.

B. Cameron and LDEQ Have Not Demonstrated That The Liquefaction Project Will Not Cause or Contribute to Exceedance of Ozone Standards

LDEQ cannot approve Cameron's project unless Cameron demonstrates "that emissions from construction or operation of [its] facility will not cause, or contribute to, air pollution in excess of" the 8-hour ozone "national ambient air quality standard in any air quality control region." 42 U.S.C. § 7475(a)(3). Cameron has not made this showing. On the contrary, the materials Cameron submitted affirmatively indicate that the project will cause or contribute to violation of the 8-hour ozone NAAQS. The ozone impact analysis provided by Cameron indicates that the project will increase ozone levels in surrounding regions, including areas already designated as in violation of the ozone NAAQS and other areas approaching the threshold. Although LDEQ has asserted that these increases in ozone levels are insignificant, this assertion is unsupported and is contrary to the Clean Air Act. Moreover, Cameron's ozone impact analysis, and LDEQ's discussion thereof, understate the project's impacts, by failing to account for the full range of ozone precursor emissions attributable to the project (including secondary and induced growth emissions) and by failing to include other permitted projects in the baseline.

1. Areas Near The Proposed Facility Are In or Approaching Non-Attainment of the 8-Hour Ozone NAAQS

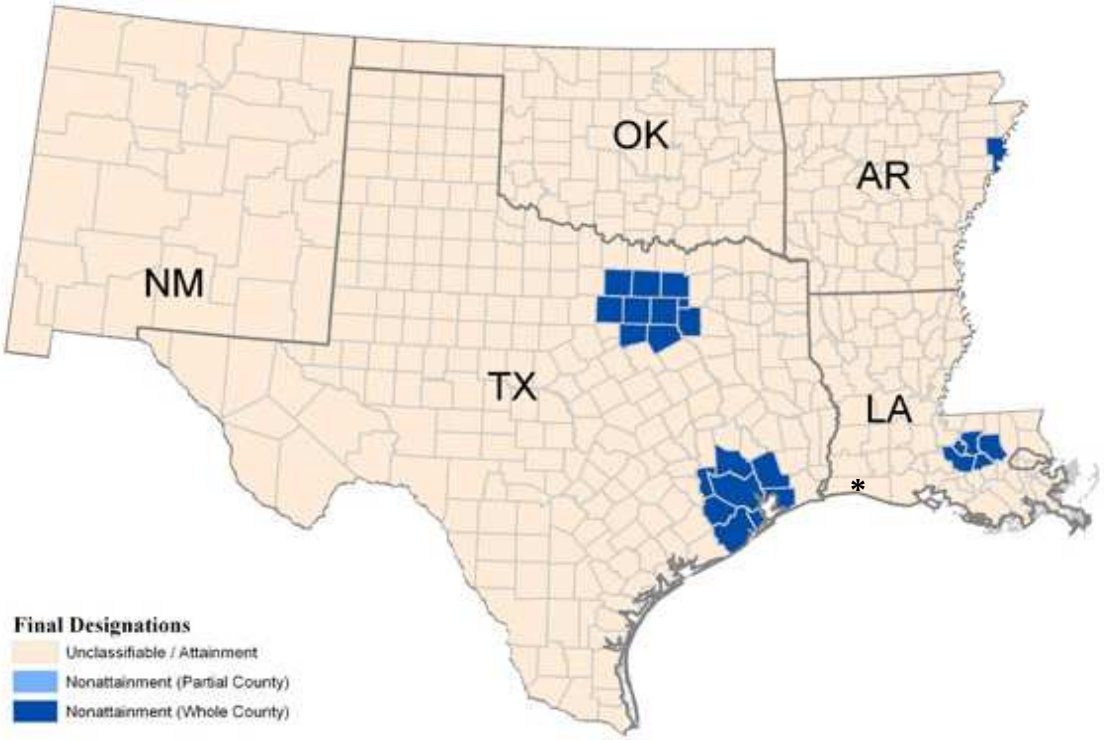
The 8-hour ozone NAAQS is 75 ppb, based on the annual fourth-highest daily maximum 8-hour average concentration. National Ambient Air Quality Standards for Ozone, 73 Fed. Reg. 16436 (Mar. 27, 2008). The three-year average of annual fourth-highest daily maximum 8 hour concentrations is referred to as the "design value" for the standard. [31] EPA designates areas as being in "attainment" or "non-attainment" of the NAAQS. An area is in "attainment" of this standard when the design value measured at each monitoring site is less than 76 ppb. Conversely, an area is in non-attainment of this standard when it "does not meet (or . . . contributes to ambient air quality in a nearby area that does not meet)" the 75 ppb ozone standard. 42 U.S.C. § 7407(d)(1)(A)(i).

The facility is near, and will potentially affect, three areas designated as non-attainment of the 8-hour ozone NAAQS. Although the terminal itself is in a region of Louisiana that is designated as in attainment with all national ambient air quality standards (NAAQS), as shown in Figure 1, this location is sandwiched between 8-hour (2008) ozone nonattainment areas: to the east, the Baton Rouge Metropolitan Statistical Area, and to the west, the Houston-Galveston-Brazoria area and, somewhat more distantly, the Dallas-

[31] *See* 40 C.F.R. Pt. 50, App'x I.

Fort Worth. The facility location is indicated by the "*" in figure 1. EPA published ozone classifications for counties in Texas and Louisiana in May 2012. EPA, *Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standard*, 77 Fed. Reg. 30,088 (May 12, 2012).

Figure 1. Final Designations for
2008 8-Hour Ozone Standard (May 2012) in Region 6



In addition, the nearby Beaumont/Port Arthur area is approaching or already violating the 8-hour ozone NAAQS, despite having been designated as in attainment in the EPA's May 2012 rule. That attainment designation was based on "certified" 2008-2010 ambient monitoring data, which covered a period when ozone was anomalously low due to the recession. Subsequent to EPA's rulemaking, the more recent 2010-2012 data has been certified. Of the nine monitors in this Beaumont/Port Arthur area, five cross or are on the cusp the standard. Specifically, the 2010-2012 average of fourth highest annual ozone concentrations for one is in clear violation at 80 ppb;[32] two others are at 75 ppb,[33] such that any increase would cause violation of the standard; and two more are at 74 ppb, such

[32] Monitor 482450101, 5200 Mechanic St., Port Arthur, Texas.
[33] Monitor 482450009, at 1086 Vermont Avenue in Beaumont, Texas, and Monitor 483611001, at 2700 Austin Ave, West Orange, Texas.

that an increase of over 1 ppb would violate the standard.[34] Table 2 presents the data from EPA's website that we used to calculate this data.[35]

Table 2.
Excerpted Certified 2010 to 2012 8-Hour Ozone Data for the Beaumont/Port Arthur Metropolitan Statistical Area

County	City	Address	Site ID	4th Max 2012	4th Max 2011	4th Max 2010	Average
Jefferson	Beaumont	1086 Vermont Avenue	482450009	0.075	0.076	0.074	0.075
Jefferson	Port Arthur	623 Ellias Street	482450011	0.066	0.076	0.08	0.074
Jefferson	Not in a city	12552 Second St	482450022	0.073	0.075	0.07	0.073
Jefferson	Port Arthur	5200 Mechanic	482450101	0.076	0.084	0.081	0.08
Jefferson	Port Arthur	Jefferson County Airport	482450102	0.07	0.073	0.071	0.071
Jefferson	Not in a city	Unavailable	482450628	0.081	0.07	0.07	0.074
Jefferson	Nederland	135 Hare Road	482451035	0.069	0.074	0.075	0.073
Orange	West Orange	2700 Austin Ave	483611001	0.072	0.075	0.077	0.075
Orange	West Orange	Intersection Of Tx Hwys 62 And 12	483611100	0.067	0.072	0.07	0.07

Thus, if classified today, Jefferson County, Texas, would be in nonattainment for the 8-hour ozone NAAQS.

Monitors in Calcasieu Parish, Louisiana, closer to the project site, also indicate potential 8-hour ozone NAAQS violations. In particular, monitor 220190002, at highways 27 and highway 108, has 2010-2012 design values of 74 ppb, putting at the cusp of non-attainment.[36]

---

[34] Monitor 482450011, at 623 Elias Street, Port Arthur, Texas and Monitor 483611001, 2700 Austin Ave, West Orange. Indeed, while the 2010-2012 for the Elias Street monitor was 74 ppb, indeed, the 2009-2011 average for this monitor was 76 ppb.

[35] Available at http://www.epa.gov/airdata/ad_rep_mon.html. Hardin County, the third county in the Beaumont/Port Arthur area, appears not to include any monitoring stations for ozone, and is therefore not included on this table. For general information on calculation methods, *see* 40 CFR Part 50, Appendix I.

[36] Fourth-highest 8 hour ozone averages for 2010 to 2012 for this monitor are 78, 72, and 72 ppb, respectively.

2. The Proposed Project Will Increase Ambient Ozone Levels In Nearby Regions Exceeding or Approaching The 8-Hour Ozone NAAQS

As the Cameron's Ozone Impact Analysis demonstrates, and as LDEQ's draft permit acknowledges, the liquefaction facility will increase 8-hour ozone concentrations in nearby areas.[37]

The Ozone Impact Analysis used a state-of-the-art photochemical model, the Comprehensive Air Quality Model with Extensions (CAMx), as recommended by U.S. EPA Region 6. A previous attainment demonstration based on a known ozone episode (May 26 to July 1, 2006) was modified to include NO_x and VOC emissions from the LNG project. A historic ozone episode is used in the modeling analysis as the modeling requires a detailed emission inventory for the subject area. This particular episode was selected as it encompassed nearly two-thirds of the high ozone days in the Beaumont-Port Arthur region, the Texas area closest to the project and which at the time was classified as "maintenance" for the 8-hour ozone standard. The ozone impact analysis predicts the impact of the project by comparing models of "baseline" scenarios against models to which emissions of ozone precursors from the facility have been added. The analysis includes "relative" models, which concern "design values," or the three year average of fourth highest 8-hour ozone episode (referred to as "relative" modeling), as well as "absolute" values, which concern ozone levels on particular days of the modeled episode. Both the relative and absolute models are presented in two geographic formats: predictions of levels at the locations of existing monitors and predictions for unmonitored areas using modeling to predict both the baseline and project levels for these areas.

At monitored locations, the relative ozone impact analysis predicts ozone design value increases at 18 monitors, including 13 monitors where the after-project levels are predicted to exceed the NAAQS.[38] Many of these increases occur in the Houston-Galveston-Brazoria non-attainment area. For example, at five monitors in Harris County where the design values for 8-hour ozone exceed 75 ppb, the model predicts a 0.1 ppb increase in ozone design values.[39] In other areas not currently designated as non-attainment, model predicts increases additional attributable to the project, with many resulting design values in excess of 75 ppb. At all seven monitors in Jefferson County, the ozone analysis predicts that the project will increase ozone design values by 0.1 to 0.2 ppb, and the design values for all but one monitor exceed 75 ppb.[40] Every monitor in Calcasieu Parish is predicted to experience 0.2 ppb increases, with two of the three monitors having design values exceeding 75 ppb. Finally, the liquefaction project may also cause or contribute to exceedances in Orange County, Texas. There, the analysis

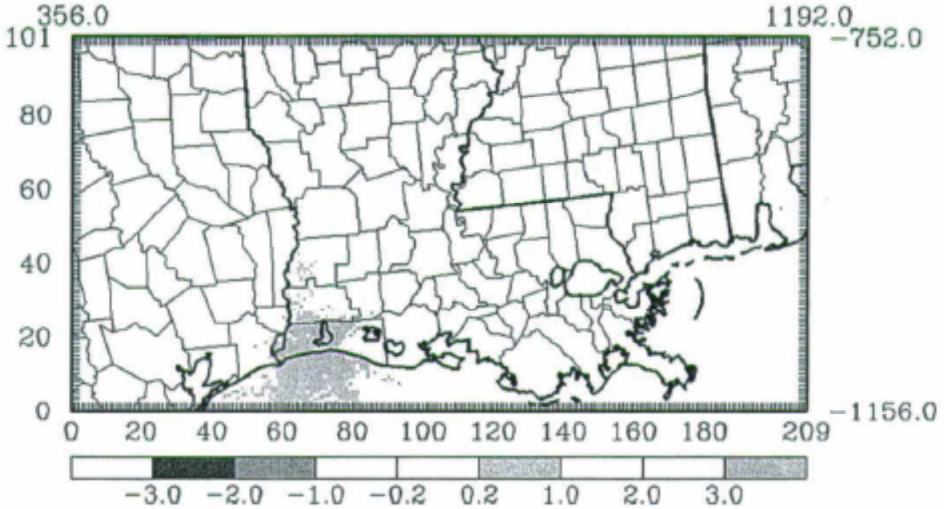
---

[37] Dennis McNally and Cyndi Loomis, Alpine Geophysics, LLC, Ozone Impact Analysis of the Proposed Cameron LNG Facility, Technical Report, April 29, 2013.
[38] Ozone Impact Analysis, Table 3-1.
[39] *Id.* at 3-4.
[40] *Id.* at 3-4 to 3-5.

predicts 0.1 ppb increases in ozone levels. Although the analysis predicts that the resulting ozone level will nonetheless remain below 75 ppb, more recent baseline data, discussed in the preceding section, indicates that levels in Orange County are already at the 75 ppb threshold.

Separate from the analysis of impacts at monitor locations, the Ozone Impact Analysis also modeled design value impacts at unmonitored areas. This modeling further indicates increases in ozone. These impacts are summarized in Figure 2:

Figure 2. 8-hour Ozone Future Year Design Value Differences
for the 2009 Cameron LNG Project Emissions Case
Minus the 2009 Future Year Base Case Projected Baseline Case



Finally, in addition to these models of design values, the ozone impact analysis's absolute modeling provides further evidence of increases in ozone levels. As summarized by LDEQ, for the 37 day modeling run, the model predicts onshore ozone impacts of greater than 2.0 ppb on one day.[41] The absolute model reflects individual days during the modeled event, for both monitored areas and unmonitored regions. The geographic, unmonitored-area modeling indicates that LNG facility emissions increase 8-hour ozone in the following non-attainment areas:

- Galveston and Harris Counties, June 3, 2006, p. A-6
- Chambers County, June 14, 2006, p. A-11
- Chambers County, June 29, 2006, p. A-10

Furthermore, the modeling of unmonitored regions indicates that the liquefaction facility will increase 8-hour ozone concentrations by 0.2 to 1 ppb in Jefferson County, Texas.

[41] Draft PSD Permit, Preliminary Determination Summary at 16.

Ozone Impact Analysis, Figure 3-6 and pp. A-6 (6/3), A-7 (6/5), A-9 (6/9), A-11 (6/14), A-19 (6/30), to A-14, A-16, A-17, A-19 to A-21, A-35 to A-37.

3. These Increases in Ozone Will Cause or Contribute to Violations of the NAAQS

Because the proposed project would increase 8-hour ozone concentrations beyond 75 ppb, Cameron has not demonstrated "that emissions from construction or operation of [its] facility will not cause, or contribute to, air pollution in excess of" the 8-hour ozone "national ambient air quality standard in any air quality control region." 42 U.S.C. § 7475(a)(3). Any increase in ambient ozone levels in an area that is in nonattainment of the 8-hour ozone SIP is, by definition, a contribution to air pollution in excess of the standard. The ozone impact analysis's models indicate that the project will increase ozone levels for the three year average of the fourth highest day at monitor sites in areas presently designated as non-attainment and where baseline design values already exceed the 75 ppb level. Accordingly, there can be no dispute that the project will "contribute to[] air pollution in excess of" the standard at these sites. The ozone impact analysis further indicates that the project may cause and/or contribute to, exceedance of the standard in Jefferson County and other areas not currently designated in non-attainment.

Although LDEQ's draft permit states that the project's impacts on 8-hour ozone will be "insignificant,"[42] this unsupported assertion cannot be squared with the governing law. The Clean Air Act provision at issue here prohibits "caus[ing] or contribut[ing]" to NAAQS violations without qualification. 42 U.S.C. § 7475(a)(3). This stands in stark contrast to other provisions of the Clean Air Act, such as the section 42 U.S.C. § 7410(a)(2)(D)(i)(l), which prohibits emissions that will "contribute *significantly*" to nonattainment in another state. (emphasis added). Thus, had Congress intended section 7475(a)(3) to be limited to significant contributions, the provision would have included such a qualifier. Thus, any predicted increase, including the 0.1 ppb increases modeled for some areas, that occurs in non-attainment area contributes to exceedance of the NAAQS. Nor can the emissions from this facility be said to be *de minimus*. In a recent decision regarding the Sabine Pass liquefaction project, LDEQ concluded that "the Clean Air Act . . . plainly allows for 'de minimus' increase in ozone nonattainment areas." LDEQ's support for this contention was that the nonattainment new source review program allows increases of up to 25 tons per year of ozone precursors NOx or VOC even in severe nonattainment areas without triggering requirements to provide offsets or achieve the lowest achievable emissions rate. The 25 tons per year of ozone precursor increases treated as *de minimus* under this program are, however, a far cry from 2,567.73 tons per year of NOx and 124.57 tons per year of VOC that will be directly emitted by this proposed project.[43] Thus, the fact that the Clean Air Act's implementing regulation *explicitly* allow truly minor emissions of ozone precursors to be treated as *de minimus*

[42] Draft PSD Permit, Briefing Sheet, at 4.
[43] Draft PSD Permit, Briefing Sheet, at 2.

provides no support for the proposition that the Clean Air Act also *implicitly* allows emissions that are two orders of magnitude greater to be disregarded. Indeed, it appears likely that emission volumes below the NNSR thresholds would not produce a modelable increase in ozone levels.

4. Cameron's Ozone Impact Analysis and LDEQ's Draft Permit Understate the Project's Likely Ozone Impacts

These ozone impact estimates are too low, for two additional reasons. First, as explained above, the ozone impact analysis ignores many secondary emissions and emissions from induced growth—particularly emissions from the new production that will be caused by the liquefaction project, which will include significant ozone precursor emissions. Second, the ozone analysis appears to set the baseline emissions too low by not including other permitted facilities that have not yet entered operation, which will also have high high NO_x and VOC emissions. In particular, the Sabine Pass Liquefaction project, also in Cameron Parish, has received PSD approval from LDEQ and is currently undergoing construction. EPA modeling guidance calls for "emissions from sources with permits to construct that have not yet started operation" to be accounted for in PSD air quality analyses.[44] However, it does not appear that the emissions from Sabine Pass were included in the model. The NO_x and VOC emissions from these projects will contribute to baseline ozone levels, perhaps classifying more impacted counties as ozone nonattainment. Accordingly, baseline emissions are likely higher than presumed in the ozone impact analysis, such that it is more likely that the liquefaction project's emissions will push those areas over (or further past) the 75 ppb threshold.

IV. The Proposed BACT Analysis Is Inadequate

Cameron proposes to construct three individual natural gas liquefaction trains, powered by six refrigeration compressor turbines.[45] The application's NOx, CO, VOC, PM (PM10, PM2.5), and GHG BACT analyses are deficient because they fail to consider the use of electrically powered compressors or to require that compressor turbines utilize heat recovery, and because they improperly reject various control technologies that are both technically feasible and cost effective for the proposed turbines.

[44] See section 8.2.2.k and Table 8.2 of 40 C.F.R. § 51, App'x W – Guideline on Air Quality Models. EPA's NSR Manual also states that it is "necessary to include in the NAAQS inventory those sources which have received PSD permits but have not yet begun to operate." NSR Manual at C.34.

[45] Draft PSD Permit, Preliminary Determination Summary, at ¶ III.

A. The BACT Analyses Must Consider Alternatives to the Proposed Gas-Fired Turbines

As a threshold matter, the project could do away with compression turbines entirely by using electrical compression. Electrically driven compression, powered by the grid, is a feasible alternative. At least two applications for construction of domestic LNG export terminals propose to use this option. Freeport LNG Developlment, L.P., *et al.*, FERC Dkt. No. CP-12-509, *Application for Authorization under Section 3 of the Natural Gas Act*, 8 (Aug. 31, 2012) (proposing "electric motor-driven refrigeration and other compressors, expanders, and pumps"),[46] Jordan Cove Energy Project, L.P., DOE/FE Dkt. No. 12-32-LNG, *Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations*, 4 (March 23, 2012) (proposing "electrically driven liquefaction equipment").[47] Existing LNG export terminals in Norway, Indonesia, Africa and Saudi Arabia use electrical compression. Siemens Energy, *Pushing the Limits of Productivity: The all-electric liquefaction plant concept*, 9, 11 (2008).[48] Electrically driven compression and refrigeration is therefore an available alternative. This alternative would have vastly lower air emissions. Electric motor drivers have more efficient turndown characteristics for variable output operations, they can be sized to allow more efficient design, they generate no waste heat, and are not affected by the weather. (Turbines lose efficiency as temperatures and humidity deviate from design, a major issue for the Sabine Pass area, where high temperatures and humidity are present much of the year.) For these and other reasons, electric compression has lower emissions of conventional and greenhouse gas pollutants, even when emissions associated with upstream electricity production are considered. Electric compression and refrigeration therefore must be considered in the BACT analyses.

Further, as explained in more detail below, Cameron has not explained why, if gas turbines are to be used, Cameron is not committing to use a configuration with heat recovery.

B. The BACT Analysis Must Consider NOx, CO, and VOC Control Technologies that Can Be Applied to the Proposed Turbine Design

Even if the existing design of two gas turbines per liquefaction train is preserved, Cameron and LDEQ improperly rejected available NOx, CO, and VOC control technologies in its top down BACT analyses.

---

[46] Available at: http://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13057428

[47] Available at: http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/ 12_32_LNG_Application.pdf

[48] http://www.energy.siemens.com/us/pool/hq/industries-utilities/oil-gas/applications/lng/Pushing%20the%20limits%20of%20productivity_EN.pdf

1. Cameron and LDEQ Lack an Adequate Basis for Eliminating Selective Catalytic Reduction as BACT for NOx and CO

Cameron and LDEQ wrongly concluded that selective catalytic reduction (SCR) was economically infeasible, failed to evaluate much more effective dry low NO_x (DLN) controls for the GE Frame 7EA gas turbine, and made several other legal and factual errors in determining BACT for NOx and CO.[49]

a. Cameron's BACT analysis for SCR omits important steps integral to top-down BACT analysis.

Under the Clean Air Act's PSD regulations, Cameron must apply BACT to control its air pollution. Cameron used what EPA refers to as a "top-down" BACT analysis.[50] Under step one of this analysis, Cameron must list all potentially applicable control technologies.[51] Under step two, Cameron must document the technical infeasibility of controls "based on physical, chemical, and engineering capabilities."[52] "Where the resolution of technical difficulties is a matter of cost, the applicant [Cameron] should consider the technology as technically feasible."[53] Under step three, Cameron must rank the control technologies in order of effectiveness.[54] Under step four, Cameron must evaluate and document the energy, environmental and economic impacts of every feasible technology listed in step three unless it chooses the most stringent control.[55] Both beneficial and adverse impacts must be reported in the evaluation of the most effective controls.[56] Under step five, Cameron must select BACT.[57]

Cost effectiveness, measured in dollars per ton of pollutant removed, is calculated according to the EPA Air Pollution Control Cost Manual ("Cost Manual"),[58] in accordance with the NSR Manual, p. B.35, to assure consistency of BACT decisions made on the basis of cost. Under procedures outlined in the Cost Manual, cost effectiveness is determined by comparing annual cost per ton of pollutant removed for

---

[49] Cameron LNG, LLC, Title V Air Permit Modification/Renewal and PSD Permit Application (Aug. 2012) [hereinafter "Application"], at § 3.3.1.2.
[50] NSR Manual at B.6.
[51] NSR Manual at B.5, B.6.
[52] NSR Manual at B.6, B.7
[53] NSR Manual at B.19; B.7
[54] NSR Manual at B.6, B.7, B.8.
[55] *See* 61 Fed. Reg. at 38,273 (July 23,1996).
[56] NSR Manual B.8; *see also* 61 Fed. Reg. at 38,273 (July 23,1996).
[57] NSR Manual at B.6, B.9.
[58] U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 [hereinafter "Cost Manual"]. The EPA Air Pollution Control Cost Manual is the current name for what was previously known as the OAQPS Control Cost Manual, the name for the Cost Manual in previous (pre-2002) editions of the Cost Manual.

the source of interest to the range of cost effectiveness values for other similar permit decisions. If a given cost effectiveness value falls within the range of costs borne by others, it is per se cost effective unless unusual circumstances exist at the source.

Cameron failed to follow these guidelines in at least two ways. First, Cameron improperly mixed concepts of technical feasibility and economic feasibility. EPA's NSR Manual provides clearly that the costs of technically feasible controls are to be considered only *after* a determination of technical feasibility is made.[59] "Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible."[60] Cameron did not proceed according to these instructions. Instead, Cameron's analysis jumps from considerations of whether SCR is "practical"[61] to economic considerations,[62] and back to practical considerations.[63] Cameron ultimately concludes that "[d]ue to the economics, environmental, and energy impacts, SCR is considered to be an infeasible control option."[64] Cameron does not follow the required steps, and ultimately fails to state the precise reason – technical or economic feasibility – for eliminating SCR. Its analysis thus provides no basis for LDEQ to make a reasoned determination on this question.

Second, Cameron failed to conduct the required comparison between cost effectiveness of SCR at its proposed facility and cost effectiveness at other facilities, as required by the NSR Manual and Cost Manual.[65] Under the NSR Manual and Cost Manual, cost effectiveness is a *relative* determination. "In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT."[66] With limited exceptions, it is only when unusual circumstances *specific to the proposed facility* make costs unusually high that a finding of economic infeasibility is justified. Accordingly, the NSR Manual instructs that "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review."[67] By contrast, "applicants generally should not propose

---

[59] NSR Manual at B.8, B.19.
[60] NSR Manual at B.19.
[61] Cameron first "deemed SCR a practical control option," essentially determining it to be technically feasible. Application at § 3.3.1.3 p. 13.
[62] Application at § 3.3.1.3 tables 3-2a, 3-2b.
[63] Application at § 3.3.1.3 p. 21.
[64] Application at § 3.3.1.3 p. 21.
[65] *See* Application at § 3.3.1.3.
[66] NSR Manual at B.44.
[67] NSR Manual at B.31.

elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source."[68]

In this case, neither Cameron nor LDEQ made any attempt to conduct a comparative cost effectiveness analysis or to demonstrate "unusual and persuasive differences" between Cameron's facility and others that have installed SCR. In fact, as we show in the section that follows, SCR is quite commonly installed at facilities using the same or similar natural gas turbines. Neither Cameron nor LDEQ acknowledged this fact or attempted to show why Cameron has unique features that make SCR uneconomical. Accordingly, the record does not provide the required basis for LDEQ's conclusion that "SCR is considered economically infeasible."[69] LDEQ must require Cameron to resubmit a proper BACT analysis correcting these defects.

b. SCR has been proposed for at least one LNG facility and is frequently installed at similar simple cycle turbines used for natural gas peaking plants.

The draft permit proposes a NOx BACT limit for the Cameron gas turbines of 15 ppmv at 15% O_2 using dry low NOx combustors in combination with good combustion practices ("DLN").[70] DLN is not BACT for these turbines. SCR has been proposed for at least one LNG facility; the single Frame 7EA turbine associated with the Freeport LNG Expansion project will incorporate SCR and oxidation catalyst to meet a NOx limit of 2 ppm and a CO limit of 4 ppm.[71]

In addition, similar simple cycle turbines used for peak power generation frequently install SCR, resulting in much lower NOx levels. Simple cycle peaking turbines are comparable to the service that would be experienced at LNG terminals. A small sample of limits on similar turbines is summarized in Table 2.

[68] NSR Manual at B.31.
[69] Draft PSD Permit, Preliminary Determination Summary, p.8.
[70] Draft PSD Permit, Specific Conditions, p. 20, t.III.
[71] TCEQ, *Pending and Issued Permits – Gas Turbines Rated 20 MW and Greater Electrical Output*, March 8, 2013. Pending Application TCEQ 104480, Freeport LNG Development, GE Frame 7E.

Table 3. NOx BACT Limits for Simple Cycle Peaking Turbines.[72]

Facility	NOx Limit	Averaging Period	Control	Permit Issuance
El Cajon Energy	2.5 ppm	1-hr	Water injection and SCR	Dec 2009
Escondido Energy Center	2.5 ppm	1-hr	Water injection and SCR	Jul 2008
Orange Grove Energy	2.5 ppm	1-hr	LNB, Water injection and SCR	Dec 2008
CalPeak Power El Cajon	3.5 ppm	1-hr	SCR	Jun 2001
El Colton	3.5 ppm	3-hr	SCR	Jan 2003
Lambie Energy Center	2.5 ppm	3-hr	SCR	Dec 2002
TID Almond 2 Power Plant	2.5 ppm	1-hr	LNB, Water injection and SCR	Dec 2010
Canyon Power Plant	2.5 ppm	60 minutes	LNB, Water injection and SCR	Mar 2010
Starwood Power – Midway	2.5 ppm	1-hr	Water injection and SCR	Jan 2008
Panoche Energy	2.5 ppm	1-hr	Water injection and SCR	Dec 2007
SF Electric Reliability Project	2.5 ppm	1-hr	Water injection and SCR	Oct 2006
Niland Power Plant	2.5 ppm	1-hr	Water injection and SCR	Oct 2006
Miramar Energy Facility II	2.5 ppm	3-hr	Water injection and SCR	Nov 2008
Walnut Creek Energy Park	2.5 ppm	1-hr	Water injection and SCR	May 2011

In its application, Cameron acknowledges that some of these same units are comparable, and that they "currently operate successfully."[73] However, Cameron fails to explain why its facility is different from these facilities, and how the differences make SCR

[72] This table is drawn from a recent PSD permit for a natural gas peaking plant in San Diego. U.S. Environmental Protection Agency, Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit, Pio Pico Energy Center, PSD Permit Number SD 11-01 (June 2012), at 12-13 t.7-4, *available at* http://yosemite.epa.gov/OA/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/ED5B5D8955D5814685257AE1007431AC/$File/Petition%20for%20Review%20Exhibit%202...3.02.pdf. .

[73] Application at § 3.3.1.3 p. 13 & t.3-1.

economically unfeasible at Cameron. The SCR is indeed *more* economical at Cameron's site than it would be at the natural gas peaking facilities listed in Cameron's application and in the above Table 3. Cameron requests a permit that would allow its facility to operate over 8,700 hours per year – far more than the peaking plants listed above, which are designed only for intermittent use.

Table 4 is a list of GE Frame 7EA turbines permitted in Texas over last 10 years. All of these permitted Frame 7EA turbines have lower NO_x limits than the 15 ppm at 15% O_2 proposed NO_x limits. Most of the these units are permitted with SCR. LCEQ could readily have verified the NO_x control cost-effectiveness values in the application by contacting the suppliers of SCR to the Texas Frame 7EA projects and did not do so.

Table 4. NO_x and CO Limits for GE Frame 7EA Turbines Permitted in Texas Over Last 10 Years[74]

TCEQ permit issue date	Company	County	Control System	NO_x limit (ppm @ 15% O_2)	CO limit (ppm @ 15% O_2)
12/21/12	NRG Texas Power LLC	Fort Bend	DLN + SCR	2	9
7/24/08	East Texas Electric Coop	San Jacinto	DLN	9	25
2/14/06	Navasota Odessa Energy	Ector	DLN + SCR	5	27
2/09/06	Navasota Wharton Energy	Wharton	DLN + SCR	5	27
12/20/02	OxyVinyls	Harris	DLN + SCR	4	25

In sum, it is plain that SCR is considered economically feasible at a large number of facilities, including Frame 7EA facilities and peaking facilities at which SCR is *less* economical than it would be at the continuously operational Cameron facility. Cameron has not met its obligation to compare the economic feasibility of SCR at its facility to gas turbine economics at other sites. LDEQ must therefore require, and Cameron must provide, this information if LDEQ is to have a reasoned basis for the conclusion that SCR is not economically feasible.

c. Cameron's assessment of the cost-effectiveness of SCR at its facility contains technical flaws.

In addition to its failure to compare the cost effectiveness of SCR at its facility to cost effectiveness at comparable facilities, Cameron also overstated SCR's costs by failing to employ the cost effectiveness methodology set out in the NSR Manual and Cost Manual. LDEQ must require Cameron to correct these defects.

[74] TCEQ, *Pending and Issued Permits – Gas Turbines Rated 20 MW and Greater Electrical Output*, March 8, 2013.

Cameron's cost analysis claims high cost effectiveness: $10,238/ton for GE7EA turbines and $9,027/ton for GE7EA turbines with waste heat recovery units, based on a starting capital cost of $18.76 million for each control unit consisting of an SCR and oxidation catalyst.[75] These costs are likely too high, for a number of reasons.

Improper costing method/overstated capital costs. To compare costs among units, it is essential to establish a level playing field so that the same cost rules are followed in each determination. For this reason, the method of calculating capital costs is critical to disclose. BACT analyses are based on the "overnight" costing method while industry estimates are commonly based on the "all in" method. The two differ significantly, the latter resulting in much higher estimates.

In this case, Cameron asserts a capital cost, the starting point for the analysis, based on an unsupported estimate apparently provided by the consultant that prepared Cameron's BACT analysis. Our expert engineers advise that this cost is very high for an overnight cost estimate for the GE 7EA turbines proposed here. No effort was apparently made by Cameron LNG or its consultant to verify the actual cost of SCR installations on operational or planned Frame 7EA turbines, such as the Texas Frame 7EA turbines listed in Table 4. It is common for engineering firms to include costs in such an estimate that are not valid for a BACT cost effectiveness analysis. These cost adders may include Allowance for Funds Used During Construction (AFUDC), owner's cost, various contingencies,[76] interest during construction, and escalation, among others. Thus, the starting capital cost is likely a gross overestimate.

Improperly calculated cost recovery factor. The capital cost is converted into an annual cost by multiplying it by a carrying charge or a capital recovery factor, calculated from an assumed interest rate and SCR lifetime.[77] Cameron's analysis assumed an interest rate of 7% and a SCR lifetime of 20 years, resulting in a capital recovery factor of 9.44%.[78] These assumed values are unsupported, are inconsistent with BACT costing methodology, and are incorrect and overstate actual annual costs and hence cost effectiveness.

The use of a 7% interest rate over a 20-year term is inappropriate in an era of readily available lower-cost financing. For example, the SCAQMD recently revised its guidance on the interest rate to use in air emission control cost-effectiveness calculations. Current guidance is an interest rate of 4% over 20 years.[79]

---

[75] Application, t.3-2b p. 17.
[76] Indeed, Cameron included "contingencies" as a $1,705,320 adder in table 3-2a of the Application.
[77] *See* Cost Manual, Chapter 2 at 2-12 to 2-13.
[78] Application at t.3-2a, p. 16.
[79] Malcolm Pirnie Company, *Final Report - Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology, South Coast Air Quality*

Inaccurate equipment lifetime assumption. The lifetime used to calculate the capital recovery factor is the actual (or anticipated) service life of the equipment. An SCR is just a metal frame packed with catalyst that is changed periodically. The SCR metal frame and support structure last as long as the equipment they control: in this case, the gas turbines. The equipment lifetime is important; the shorter the lifetime, the higher the capital recovery factor and the higher the annual capital cost used to determine cost effectiveness. There are many SCRs that were installed on gas turbines in Japan and California in the 1980s that are still in operation today. Many utilities routinely specify 30+ year lifetimes in requests for proposal and to evaluate proposals. A study of the economic risks from SCR operation at the Detroit Edison Monroe power plant, for example, used 30 years as the anticipated lifetime.[80] An analysis prepared by Black & Veatch for a coal-fired boiler, a much more difficult application, assumed a 40 year SCR lifetime.[81] A 40-year service life is consistent with actual experience with existing SCRs on gas-fired turbines, as their operating environment is less harsh, i.e., natural gas is much cleaner than coal. Thus, a reasonable analysis should consider a 40-year, as well as a 20-year, service life assumption.[82] This assumption is particularly important given the lack of any permit limit placing restrictions on the length of equipment operation. When, as in this case, the lifetime of a control affects the BACT determination, a federally enforceable restriction is required to prevent further operation after a date certain. Such a date has not been proposed in the draft permit.

Recalculated cost effectiveness. The Sierra Club recalculated the cost effectiveness of SCR by correcting some of these deficiencies. We recomputed the capital recovery factor, assuming an interest rate of 4% and an SCR financial lifetime of either 40 or 20 years, but otherwise using all of Cameron's assumptions (i.e., capital cost, emission reductions). A 4% interest rate reduced

---

Management District Contract #10114, Pilot Testing of Emission Control System Plant 1 Engine 1, Orange County Sanitation District Project No. J-79, July 2011, p. 4-1. The report states that "[t]he annualized total capital project budget is based on a 20-year evaluation period and 4.0 percent annualized rate, as set forth in the SCAQMD July 9, 2010 Board Meeting Minutes, Attachment B: Assessment of Available Technology for Control of NOx, CO and VOC Emissions from Biogas-Fueled Engines – Interim Report."

[80] S.D. Unwin and others, Selective Catalytic Reduction (SCR) System Design and Operations: Quantitative Risk Analysis of Options, Presented at CCPS 17th Annual International Conference: Risk, Reliability, and Security, p. 3. Available at: http://www.unwin-co.com/files%5CSCR-Risk-Paper,CCPS-RRS2002.pdf

[81] Email from O'Brien to Van Helvoirt, September 28, 2004, Re: Cost Impact, WPS-011904 at WPS-011905.

[82] The life of the catalyst used in an SCR is shorter than the equipment itself. However, the catalyst is changed out periodically, very infrequently compared to coal-fired applications as the exhaust gases from natural gas firing are much cleaner. SCR catalyst lasts 10 plus years in gas applications, resulting in very low annual costs for replacement.

the CRF from 9.44% to 5.05% in the 40-year financing term case and to 7.36% in the 20-year financing term case.[83] GHG BACT must include waste heat recovery units on the compressor turbines. The cost effectiveness of NOx (and CO) control for the compressor turbines with waste heat recovery units, assuming a 4% interest rate and 40-year financial lifetime, drops from $9,027/ton to $7,116/ton. Assuming a 4% interest rate and 20-year financial lifetime, cost effectiveness drops from $9,027/ton to $8,116/ton. These revised cost effectiveness values fall within the range of those for other similar facilities using SCR and thus are cost-effective.[84]

Thus, if Cameron were to conduct the analysis it is required to conduct (but has not conducted), and corrected its assumptions, as described, then Cameron and LDEQ would be unable to conclude that SCR (and oxidation catalyst) can be eliminated based on cost. LDEQ must require Cameron to provide this corrected analysis.

2. Cameron and LDEQ Failed to Consider GE's Advanced DLN Package As NOx BACT for the Frame 7EA Turbines

Cameron and LDEQ also failed to consider installing GE's advanced dry low NOx package, which has the potential to reduce NOx emissions well below the 15 ppm levels Cameron proposed and LDEQ accepted. GE's advanced DLN package, which has been available for the Frame 7EA since at least 2009, is guaranteed at 5 ppm NOx.[85] LDEQ must require, and Cameron must provide, a BACT analysis for 5 ppm NOx DLN technology.

3. The BACT Analysis for Fugitive VOC Emissions Must Consider Equipment to Reduce Emissions

Piping and related components will emit methane and other VOCs, which are ozone precursors and greenhouse gases. The proposed permit allows 36.68 tons/yr of fugitive VOC emissions.[86] Cameron's VOC BACT analysis for fugitives states with no support or analysis that "it is not economically feasible to incorporate add-on controls for fugitive emissions . . . [a]s such, no additional control is determined as BACT for VOC."[87] No

---

[83] Revised CRF = i(1 + i)^#years/[(1 + i)^#years - 1] = CRF. The equation for calculating the cost recovery factor is found in the Cost Manual at p. 2-21.

[84] The calculated figures would be even lower – and thus the cost-effectiveness of SCRs even greater – using the long-term "social interest rate" promulgated by the Office of Management and Budget, currently set at a very low level.

[85] GE Energy Technical Bulletin, *Heavy Duty Gas Turbine Products*, 2009, p. 7, *available at* http://www.ge-energy.com/content/multimedia/_files/downloads/dataform_2046207337_2809806.pdf. The bulletin states that "[t]he DLN 1+ system guarantees NOx emissions of 5 ppm or less for GE 6B, 7E and 7EA gas turbines."

[86] Draft Permit, Specific Conditions, at 21.

[87] Application § 3.7, p. 33.

evidence is presented that it is not economically feasible to control these emissions, and there is therefore no basis for LDEQ to adopt Cameron's conclusion.

For many pumps, flanges, and similar equipment, "leakless" and less-leaky designs are available, and the BACT analysis must consider use of such equipment. For example, one PSD permit application for a proposed petroleum refinery and integrated gasification combined cycle power plant, in discussing BACT for piping and other equipment leaks, observed that "[f]or certain service applications, components with inherently leakless design features are available. These components reduce VOC emissions, regardless of the quality or frequency of LDAR activities."[88] These include various leakless pumps and designs that fully weld, rather than bolt, connections between components. Where leakless designs are available, they achieve 100% control efficiency. Even where truly "leakless" designs are unavailable, there may be available alternatives with inherently lower fugitive emission rates. The BACT analysis must explore these opportunities.

Where leakless components are not available, a Leak Detection and Repair ("LDAR") program must be adopted. Cameron apparently proposes no monitoring for fugitive components as they are not subject to monitoring under LAC 33:III.2121.C2.[89] This does not exempt fugitive components from LDAR under PSD provisions, however. The BACT analysis must consider LDAR regimes, such as the Bay Area Air Quality Management District's Regulation 8, Rule 18 standards for equipment leaks.[90]

4. LDEQ and Cameron's Flare BACT Determination is Deficient

The three proposed flares at the proposed facility – a dry flare, wet flare, and operational flare – are all elevated flares. An enclosed ground flare is a superior alternative to these elevated flares and should have been identified as BACT for the Cameron flares by LDEQ. Ground flares have been proposed at one LNG facility (the Freeport LNG Expansion Project in Texas), and are currently in use at another (Darwin LNG facility in Australia).[91,92]

---

[88] Hyperion Energy Center, *PSD Permit Application submitted to S. Dakota Dept. of Environmental Review and Natural Resources*, 88 (Dec. 2007), *available at* http://denr.sd.gov/Hyperion/Air/20071220HyperionApplication.pdf

[89] Application at § 3.7, p. 33.

[90] This rule is available at: http://baaqmd.gov/~/media/Files/Planning%20and%20Research/Rules%20and%20Regs/reg%2008/rg0818.ashx?la=en

[91] Trinity Consultants, *Freeport LNG Development - Greenhouse Gas PSD Application*, December 2011, p. 5-2. "The Liquefaction Plant flare system will consist of a flare header system and the enclosed ground flare."

[92] D. Yates – Darwin LNG, *THE DARWIN LNG PROJECT - LE PROJET DE GNL DE DARWIN*, 14th International Conference & Exhibition on Liquefied Natural Gas, Doha, Qatar, 21-24 March, 2004, p. PS6-1.9.

The elevated flare's exposure to wind significantly reduces combustion efficiencies. In addition, direct monitoring of an elevated flare is not as feasible as it is with a ground flare. This can be remedied by the use of an enclosed ground flare.

The Bay Area Air Quality Management District (BAAQMD), where five large petroleum refineries are located, identifies use of an enclosed ground flare as BACT for flare emissions. The BAAQMD also assigns an assumed VOC destruction efficiency of 98.5% to an enclosed ground flare, higher than the assumed destruction efficiency of 98% assumed by the BAAQMD for all other flares.[93] This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds.

URS, a major U.S. engineering, design, and procurement (EPC) contractor with LNG project experience,[94] has acknowledged the superior CO destruction efficiency of enclosed ground flares relative to elevated flares, stating: "Compared to an elevated flare, an enclosed ground flare offers better CO destruction."[95]

The advantages of enclosed ground flares are reduced flame visibility, minimal heat and noise, ease of emissions sampling, smokeless combustion, and high destruction efficiencies attained by assuring the appropriate residence time.[96] Elevated flares are primarily elevated to reduce the impact of radiant heat and light during flaring events, not as a ground level impact air contaminant mitigation measure. Enclosed ground flares largely eliminate the effects on workers and nearby residents of radiant heat and light during flaring events.

In addition, an operational challenge for elevated flares during periodic flaring of relatively small volumes of process upset gases is susceptibility to poorer performance in crosswinds. The average annual windspeed in Cameron, Louisiana is approximately 13

---

[93] BAAQMD BACT Guidelines, Section 3: Petroleum Industry, Refinery Flare, *available at* http://hank.baaqmd.gov/pmt/bactworkbook/default.htm

[94] URS Corp overview of work performed for Gladstone LNG Project, *available at* http://www.urscorp.com/Projects/projView.php?s=1049&sec=39&pn=7.

[95] URS, *Best Available Control Technology (BACT) Analysis Hydrogen Energy California Project Kern County, California*, prepared for Hydrogen Energy California LLC, May 2012, p. 55.

[96] Flare Industries, Inc. webpage, "General Description - Enclosed Ground Flares," *available at* http://www.flareindustries.com/products/thermal-oxidizers-enclosed-flares/files/10-enclosed-ground-flares.pdf.

mph.[97] Test data collected on elevated flares by EPA to establish a destruction efficiency of 98% for elevated flares was all gathered at crosswind speeds of 5 mph or less.[98]

In summary, enclosed ground flares represent a feasible technology that is already in use and proposed at similar facilities. This technology, which has the potential to significantly reduce VOC and CO emissions from the proposed flares at the Cameron facility, should have been considered and adopted as BACT for flares by Cameron and LDEQ.

5. LDEQ and Cameron Should Have Selected Waste Heat Recovery from Compressor Turbines and a Ship Vapor Recovery System as Greenhouse Gas BACT

LDEQ's draft permit finds that "[u]tilizing high thermal efficiency turbines that are fueled by natural gas in combination with good combustion/operating practices is BACT for GHG."[99] LDEQ failed to analyze the possibility of waste heat recovery, which has been proven to reduce greenhouse gas emissions at similar facilities. LDEQ must require Cameron to provide additional information regarding this option, and should have found that this technology is BACT for greenhouse gases ("GHGs").

The Darwin LNG Facility is the world's first liquefaction facility to utilize high efficiency aeroderivative gas turbines for its refrigeration compressors. The plant was successfully commissioned and the first LNG cargo was shipped on February 14, 2006.[100] This plant "incorporates several . . . design features to reduce greenhouse gas emissions. These include the use of waste heat recovery on the PGT25+ turbine exhaust. The waste heat is used for a variety of heating requirements within the plant. The facility also includes the installation of ship vapor recovery equipment. The addition of waste heat and ship vapor recovery equipment not only reduces emissions that would have been produced from fired equipment and flares, but also result in a reduction in plant fuel requirements. This reduction in fuel gas results in a lowering of carbon dioxide released to the atmosphere."[101]

---

[97] Usa.com, Cameron, Louisiana weather statistics, http://www.usa.com/cameron-la-weather.htm (last visited July 14, 2013).
[98] M. McDaniel – Engineering Science, Inc., *Flare Efficiency Study*, EPA-600/2-83-052, July 1983, p. 19.
[99] Draft PSD Permit, Briefing Sheet at 3.
[100] C. Meher-Homji – Bechtel Corporation et al, *World's First Aeroderivative Based LNG Liquefaction Plant – Design, Operational Experience and Debottlenecking*, Proceedings of the First Middle East Turbomachinery Symposium, Doha, Qatar, February 13-16, 2011, p. 2.
[101] *Id.* at 2.

A view of the gas turbines inlet systems is shown in Figure 3. As can be seen in the figure, four of the gas turbines have once-through steam generators located on their stacks to capture heat and produce steam, which is used for process needs.

Figure 3. Gas Turbine Compressor Trains with Four Heat Recovery Units on First Four Turbines (left to right)

The single Frame 7EA turbine associated with the Freeport LNG Expansion project will likewise incorporate waste heat recovery.[102] LDEQ and Cameron should have required this feasible technology as BACT for GHGs.

LDEQ and Cameron likewise should have considered incorporating a ship vapor recovery system to eliminate marine flares and thus reduce GHG emissions. The installation of ship vapor recovery equipment would minimize or eliminate any flaring that may occur during LNG tanker loading and the resulting greenhouse gas emissions. The use of this equipment will result in a reduction in greenhouse gas emissions that would have otherwise occurred if these vapors were flared.

The addition of waste heat and ship vapor recovery equipment not only reduces emissions that would have been produced from fired equipment and flares, but also results in a reduction in fuel requirements for the plant. This reduction in fuel gas results in an additional GHG benefit as a result of the reduction in feed gas required for liquefaction, and therefore the amount of carbon dioxide that is removed and released to the atmosphere.

[102] Trinity Consultants, *Freeport LNG Development - Greenhouse Gas PSD Application*, December 2011, p. 5-4. The application states that "[t]he heating medium is circulated from the combustion turbine waste heat exchangers to low and high temperature heaters in the amine units."

C. Either The Permit Must Prohibit Simultaneous Operation of Liquefaction and Gasification Operations, Or The Analysis Must Assume Simultaneous Operation of Both Capacities

The proposed draft permit states that Cameron will be permitted to operate liquefaction and gasification processes simultaneously. It appears that neither the permit nor application materials, however, consider the emissions that would result from such simultaneous operation, either in the air quality impact analyses or in the discussion of emissions totals. Cameron and LDEQ indicate that such simultaneous operation is unlikely, because market incentives for liquefaction and for gasification differ. Although this is likely correct, the permit and application must reflect allowable emissions. Accordingly, the permit and application must be revised to reflect the emissions that would result from simultaneous operation, to prohibit such operation, or some combination of the two (such as limiting the hours or conditions under which simultaneous operation may occur, and analyzing the impacts of that such limited simultaneous operation).

EPA recently articulated this issue in comments on the nearby Sabine Pass liquefaction project, leading LDEQ to limits such as Sierra Club advocates here:

> While it may not seem like the source would run both [liquefaction and gasification] operations simultaneously for very long, it is possible that they would have to operate both operations to meet contractual agreements. Without a limit that prevents the two operations from occurring frequently enough that they could lead to higher 1-hour NO2 impacts, the current demonstration is insufficient to demonstrate that the 1-hour NO2 NAAQS will not be exceeded. We note that it may only take a few days of bidirectional operation to yield modeling values that would create a greater concern with the 1-hour NO2 NAAQS demonstration. [103]

V. Conclusion

For the reasons set forth above, Commenters urge LDEQ to deny the proposed PSD and Title V permits for Cameron's proposed liquefaction project. In addition, before taking action on the proposed permits, LDEQ must require Cameron to provide extensive additional information to allow LDEQ to comply with its obligations under the Clean Air Act, the Louisiana SIP, and the Louisiana Constitution.

---

[103] EPA, Comment on Proposed Title V and PSD Permits for Sabine Pass Liquefaction Project, AI 119267, EDMS 8086267, p.3 of 7 (Aug. 15, 2011).

Commenters request that LDEQ provide a written response to these comments and request written notification of any decision on the proposed permits. Commenters also reserve the right to supplement these comments and rely on comments submitted by others in this or any future proceeding regarding the proposed permits.

Respectfully submitted July 15, 2013, by:

_____/s/_____
Ellen Medlin
Associate Attorney
Sierra Club
85 2nd St., Second Floor
San Francisco, CA 94105
Phone (415) 977-5646
Fax (415) 977-5793

_____/s/_____
Nathan Matthews
Associate Attorney
Sierra Club
85 2nd St., Second Floor
San Francisco, CA 94105
Phone (415) 977-5695
Fax (415) 977-5793

CC:
Ron Curry
Regional Administrator
U.S. EPA Region 6
1445 Ross Avenue
Suite 1200
Dallas, Texas 75202

Air Permits Division
U.S. EPA Region 6
1445 Ross Avenue
Suite 1200
Dallas, Texas 75202

MAGNOLIA LNG PROJECT

Resource Report 9

AIR QUALITY AND NOISE

Docket No: CP14-____-000
30 April 2014

Submitted by:

MAGNOLIA LNG

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

CH·IV International

This page left blank intentionally.

SUMMARY OF FILING INFORMATION

INFORMATION	SECTION REFERENCE
Minimum Requirements to Avoid Rejection	
☑ 1. Describe existing air quality in the vicinity of the project. (§ 380.12(k)(1)) • Identify criteria pollutants that may be emitted above EPA-identified significance levels.	Section 9.2.3
☑ 2. Quantify the existing noise levels (day-night sound level (Ldn) and other applicable noise parameters) at noise sensitive areas and at other areas covered by relevant state and local noise ordinances. (§ 380.12(k)(2)) • If new compressor station sites are proposed, measure or estimate the existing ambient sound environment based on current land uses and activities. • For existing compressor stations (operated at full load), include the results of a sound level survey at the site property line and nearby noise-sensitive areas. • Include a plot plan that identifies the locations and duration of noise measurements. • All surveys must identify the time of day, weather conditions, wind speed and direction, engine load, and other noise sources present during each measurement.	Section 9.3.2
☑ 3. Quantify existing and proposed emissions of compressor equipment, plus construction emissions, including nitrogen oxides (NOx) and carbon monoxide (CO), and the basis for these calculations. Summarize anticipated air quality impacts for the project. (§ 380.12(k)(3)) • Provide the emission rate of NOx from existing and proposed facilities, expressed in pounds per hour and tons per year for maximum operating conditions, include supporting calculations, emission factors, fuel consumption rate, and annual hours of operation.	Construction Emissions: Section 9.2.5.2 Operation Emissions: Section 9.2.6.1 Impacts: Section 9.2.6.2

SUMMARY OF FILING INFORMATION

INFORMATION	SECTION REFERENCE
☑ 4. Describe the existing compressor units at each station where new, additional, or modified compressor units are proposed, including the manufacturer, model number, and horsepower of the compressor units. For proposed new, additional, or modified compressor units include the horsepower, type, and energy source. (§ 380.12(k)(4))	There are no compressor stations included as part of the proposed Project; however, one will be required as part of the transportation of feed gas to the Magnolia LNG Project as explained in Resource Report 1, Section 1.13.
☑ 5. Identify any nearby noise-sensitive area by distance and direction from the proposed compressor unit building/enclosure. (§ 380.12(k)(4))	Section 9.3.2 and Table 9.3-1
☑ 6. Identify any applicable state or local noise regulations. (§ 380.12(k)(4)) • Specify how the facility will meet the regulations.	Section 9.3.1, Section 9.3.3.2, Table 9.3-9, and Section 9.3.4.2
☑ 7. Calculate the noise impact at noise-sensitive areas of the proposed compressor unit modifications or additions, specifying how the impact was calculated, including manufacturer's data and proposed noise control equipment. (§ 380.12(k)(4))	Section 9.3.3.2, Table 9.3-9, and Section 9.3.4.2
Additional Information Often Missing and Resulting in Data Requests	
☑ Provide copies of application for state air permits and agency determinations, as appropriate.	Appendix 9.E *[pending LDEQ review]*
☑ For major sources of air emissions (as defined by the EPA), provide copies of applications for permits to construct (and operate, if applicable) or for applicability determinations under regulations for the prevention of significant air quality deterioration and subsequent determinations.	Appendix 9.D *[pending LDEQ review]*
☑ Describe measures and manufacturer's specifications for equipment proposed to mitigate impact to air and noise quality, including emission control systems, installation of filters, mufflers, or insulation of piping and building, and orientation of equipment away from noise-sensitive areas.	Sections 9.1.1, 9.2.6, and 9.3.3.2 and Table 9.3-8

TABLE OF CONTENTS

Section Page

Summary of Filing Information i
Tables v
Figures vi
Appendices vii
Acronyms and Abbreviations vii

9 AIR QUALITY AND NOISE 1

9.1 PROJECT DESCRIPTION 1
9.1.1 Proposed Facilities 1
9.1.2 Location of Proposed Facilities 2
9.1.3 Project Site Lease Agreements 2
9.1.4 LNG Vessel Loading 4
9.1.5 LNG Truck Loading 6
9.1.6 Feed Gas and Interconnect Pipeline 6

9.2 AIR QUALITY 7
9.2.1 Climate and Meteorology 7
9.2.2 National and Louisiana Ambient Air Quality Standards 8
9.2.3 Existing Air Quality and Attainment Status 9
9.2.4 Applicable Regulations and Permitting 11
9.2.4.1 Federal Regulations 11
9.2.4.2 Louisiana Regulations 15
9.2.4.3 Air Permitting Requirements 15
9.2.5 Air Pollutant Emissions – Construction 16
9.2.5.1 Construction Emissions – Methodology 16
9.2.5.2 Construction Emissions Results 18
9.2.5.3 Construction Emissions – General Conformity 20
9.2.6 Air Pollutant Emissions – Operation 20
9.2.6.1 Emission Estimates 21
9.2.6.2 Ambient Impact Analysis 26

9.3 NOISE 26
9.3.1 Noise Regulations 27
9.3.2 Existing Noise Levels 27
9.3.3 Acoustical Analyses 34
9.3.3.1 Construction Noise 34
9.3.3.2 Operational Noise 40
9.3.4 Mitigation 47
9.3.4.1 Project Construction 47
9.3.4.2 Project Operation 47

Section Page

9.4 CUMULATIVE IMPACTS 47
9.4.1 Air Quality 47
9.4.2 Climate Change 49
9.4.3 Noise 50
9.5 REFERENCES 50

TABLES

Page

Table 9.2-1 Baseline Climate Data (1981-2010) for Lake Charles, Louisiana 8
Table 9.2-2 Background Ambient Air Quality (2010 to 2012) and Ambient Air Quality Standards 10
Table 9.2-3 Comparison of Facility Emissions to PSD Significant Emission Rates 12
Table 9.2-4 Total Construction Emissions By Year 19
Table 9.2-5 Potential Operation Emissions (tons per year) for the Project 22
Table 9.3-1 Existing Noise Level Summary for the Project Site 28
Table 9.3-2 Site Preparation Construction Noise Levels at Various Distances 34
Table 9.3-3 Facility Construction Noise Levels at Various Distances 35
Table 9.3-4 Pile-Driving SPLs at NSAs 36
Table 9.3-5 Pile-Driving Duration 36
Table 9.3-6 Dredging SPLs at NSAs 39
Table 9.3-7 Unmitigated Sound Levels for Major Noise-Producing Equipment 43
Table 9.3-8 Noise Control Reduction Values 43
Table 9.3-9 Summary of Project Operation Noise Levels at NSAs and Expected Increase in Ldn Above the Existing Ldn 43

FIGURES

Page

Figure 9.1-1 General Location Map of the Magnolia LNG Project 3
Figure 9.1-2 Project Site Boundary Map 4
Figure 9.1-3 Artist's Rendering of Proposed Facility Layout 5
Figure 9.3-1 Noise Sensitive Area (NSA) Locations Nearest the Magnolia LNG Project Site 29
Figure 9.3-2 Hourly LAeq Noise Level (dBA) – Receptor 1 31
Figure 9.3-3 Hourly LAeq Noise Level (dBA) – Receptor 2 32
Figure 9.3-4 Hourly LAeq Noise Level (dBA) – Receptor 3 33
Figure 9.3-5 Approximate Location of Pile-Driving Activities in Relation to Noise Sensitive Area (NSA) Locations 37
Figure 9.3-6 Approximate Dredging Location in Relation to Noise Sensitive Area (NSA) Locations 41
Figure 9.3-7 Locations of Major Noise-Producing Equipment (1 of 4 Trains) 45

APPENDICES

Appendix 9.A: Construction Emissions

Appendix 9.B: Operational Emissions

9.B.1 Operational Emissions Calculations
9.B.2 Fugitive Emissions Calculations *[PRIVILEGED]*

Appendix 9.C: Air Modeling Protocols and Associated Correspondence

9.C.1 Air Quality Modeling Protocol
9.C.2 Marine and Stationary Sources Air Quality Modeling Protocol
9.C.3 Modeling Protocol - Ozone Impact Analysis of the Proposed Magnolia LNG Project

Appendix 9.D: Noise Study

Appendix 9.E: Air Permit Application *[Pending LDEQ Review]*

ACRONYMS AND ABBREVIATIONS

BOG	boil-off gas
BTEX	benzene, toluene, ethylbenzene, and xylene
BTU	British thermal unit
CAA	Clean Air Act
CFR	Code of Federal Regulations
CHP	combined heat and power
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
Commission	Federal Energy Regulatory Commission; also the FERC
dB	decibel(s)
dBA	A-weighted decibel(s)
ECA	Emission Control Area
FERC	Federal Energy Regulatory Commission; also the Commission
GHG	greenhouse gas
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HHV	higher heating value
HP	high pressure
Hz	Hertz
IMO	International Maritime Organization
km	kilometer(s)
KMLP	Kinder Morgan Louisiana Pipeline
kW	kilowatt(s)
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
Ldn	Day-Night Average Sound Level
LDWF	Louisiana Department of Wildlife and Fisheries
L_{eq}	Equivalent Sound Level
L_{max}	the maximum instantaneous noise level during a specific period of time

m^3	cubic meters
Magnolia	Magnolia LNG, LLC
MARPOL	International Convention for the Prevention of Pollution from Ships
MMBtu	million British thermal units
MOVES	Motor Vehicle Emission Simulator
MR	mixed refrigerant
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NRDA	Natural Resources Damage Assessment
NSA	noise sensitive area
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	ozone
OSMR®	Optimized Single Mixed Refrigerant
Pb	lead
PM_{10}	particulate matter 10 microns or less in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
Port District	Lake Charles Harbor & Terminal District
ppb	parts per billion
ppm	part(s) per million
ppmw	parts per million by weight
Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RICE	Reciprocating Internal Combustion Engine
RR	Resource Report

SIL	significant impact level
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Station
SMR	single mixed refrigerant
SO_2	sulfur dioxide
SPL	sound pressure level
TAP	toxic air pollutant
tpy	tons per year
Trunkline LNG	Trunkline LNG LLC
Trunkline LNG project	Trunkline LNG, LLC, Lake Charles Export Terminal
U.S.C.	United States Code
USEPA	U.S. Environmental Protection Agency
VdB	vibration velocity level in decibels
VOC	volatile organic compound

9 AIR QUALITY AND NOISE

Magnolia LNG, LLC (Magnolia) has prepared this Resource Report (RR) 9 in compliance with the requirements of the Federal Energy Regulatory Commission (FERC or the Commission) regulations for authorization under Section 3(a) of the Natural Gas Act to site, construct and operate facilities necessary to liquefy natural gas at a proposed site in Lake Charles, Louisiana. On March 12, 2013, Magnolia requested approval to participate in the FERC Pre-Filing Process to assist in the identification and proper assessment of issues and to provide input into the development of the environmental resource reports. The FERC granted this request on March 20, 2013, and assigned Pre-Filing (PF) Docket Number PF13-9-000.

This RR 9 describes existing air quality and noise conditions that will be directly or indirectly affected by construction and operation of the proposed Magnolia LNG Project (referred to herein as the Project). It characterizes and quantifies existing air quality and noise; identifies affected noise-sensitive areas; and includes discussions of potential impacts on air quality and noise from construction activities and operation of the proposed facilities. RR 9 also summarizes federal, state, municipal, and other local agency air quality and noise regulations applicable to the proposed Project and, as appropriate, discusses forms of mitigation that will be used to reduce impacts during construction and operation of the facilities associated with the Project. Information contained in this RR was obtained from equipment vendor data sheets, desktop analysis, and review of available literature.

9.1 PROJECT DESCRIPTION

9.1.1 Proposed Facilities

Magnolia is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The Project would receive natural gas via a tie-in to an existing interstate pipeline that traverses the proposed Project site (refer to Section 9.1.6 below for additional information). For additional information concerning the Project Description, please refer to RR 1, "General Project Description."

The natural gas would be treated, liquefied, and stored on-site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states. The Project site is well-positioned to provide access for loading of LNG carriers and also for potential LNG barges and LNG trucks.

Approximately 1.4 billion standard cubic feet per day of natural gas would be contracted to support Project operations. Each LNG train has a guaranteed capacity of 1.7 mtpa of LNG,

and a nominal capacity of 2.0 mtpa of LNG. A key aspect of the Magnolia LNG Project is the use of the patented and highly efficient OSMR® liquefaction process. This process utilizes existing and proven technologies in an innovative way to achieve better performance. In particular, the design incorporates the use of a combined heat and power (CHP) system, and an Ammonia Auxiliary Refrigeration Plant.

The CHP technology is employed to recover the waste heat from the gas turbines within each LNG train. The recovered waste heat produces high pressure (HP) steam via once through steam generators mounted on the gas turbine exhausts. The produced HP steam is used to power steam turbines that drive the ammonia compressors within the LNG train, plus other process steam users. These ammonia compressors drive the Ammonia Auxiliary Refrigeration Plant.

The Ammonia Auxiliary Refrigeration Plant, driven from recovered free waste heat, provides additional cooling in three locations within the OSMR® liquefaction process. Firstly, the ammonia refrigerant is applied to cooling the wet gas exiting the amine contactor. Secondly, it is applied to cooling the inlet air of each gas turbine which increases the output of the gas turbine while improving stability. Lastly, it is used to pre-cool the mixed refrigerant (MR) prior to entering the cold box. These applications of these features result in an efficiency improvement of approximately 30 percent which translates into approximately 30 percent less air pollutant emissions per unit of LNG produced.

9.1.2 Location of Proposed Facilities

The Project would be located on the south shore of the Industrial Canal on the Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, Louisiana. The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′ 54.00″ W. Figure 9.1-1 is a general location map of the Project.

9.1.3 Project Site Lease Agreements

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement with the Lake Charles Harbor & Terminal District (Port District) for approximately 107.59 acres of the approximately 115-acre Project site (see Port District Option Agreement, in Appendix 1.C.1 of RR 1). The Port District Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each for a total of 70 years. Subject to compliance with the terms of the Port District Option Agreement, Magnolia may exercise the option and enter into the ground lease with the Port District at any time.

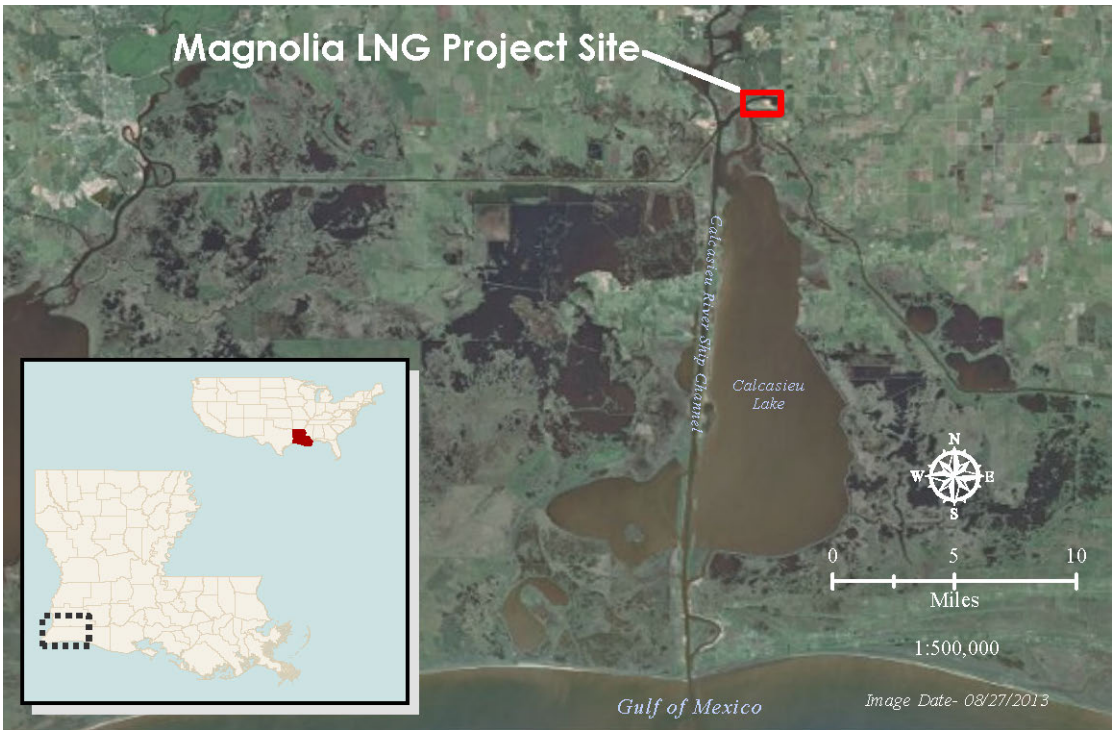


Figure 9.1-1 General Location Map of the Magnolia LNG Project

On September 26, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement with BG LNG Services, LLC, for approximately 5.74 acres of the approximately 115-acre Project site (see Appendix 1.C.2 in RR 1). On October 21, 2013, Magnolia signed the First Amendment to the Port District Option Agreement (see Appendix 1.C.3 in RR 1) for an additional area of approximately 1.99 acres. These two agreements are on similar terms and conditions as the initial Port District Option Agreement.

Through the combination of the Port District Option Agreement, the BG LNG Option Agreement, and the First Amendment to the Port District Option Agreement, Magnolia will have control of the entire area comprising the approximately 115-acre Project site for at least the minimum expected operational life of the Project, which is 30 years, with the right to extend the lease term. Figure 9.1-2 shows the boundary of the total leased area.

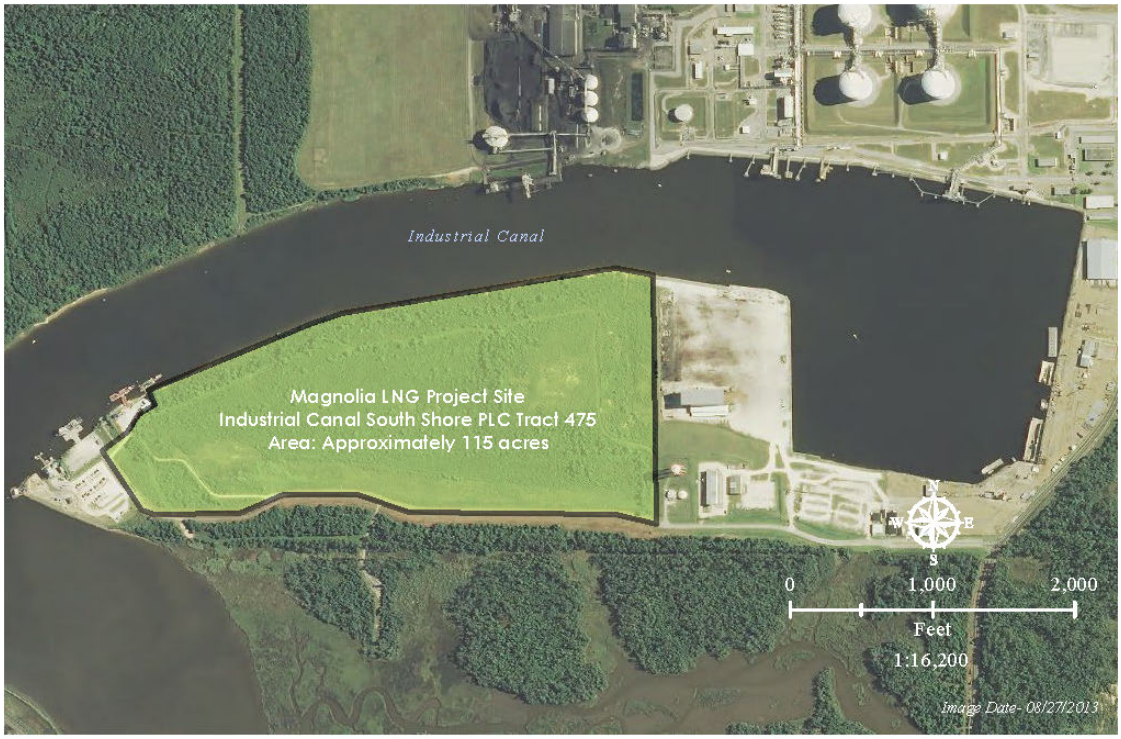


Figure 9.1-2 Project Site Boundary Map

9.1.4 LNG Vessel Loading

LNG carriers would access the Magnolia site by proceeding inbound from the Gulf of Mexico, into the Calcasieu River Ship Channel, traveling northbound to the "Devil's Elbow" intersection, and then turning right (easterly) into the Calcasieu River Industrial Canal and proceeding another 2 miles northeast to the Industrial Canal turning basin and subsequently mooring at the Magnolia LNG facility on the south side of the Industrial Canal. The total inbound transit from the entrance to the Calcasieu River jetties at the Gulf of Mexico to the Project site is approximately 25.5 statute miles. The route is reversed for outbound LNG carrier transits.

To accommodate LNG vessels and to minimize interference with existing canal traffic, the LNG vessel loading facility is planned to be recessed into the northern boundary of the site (see Figure 9.1-3). The following components are included as part of the LNG vessel loading platform: main incoming cryogenic loading line of nominal 30-inch size (outside diameter of 32 inches; pipe schedule 10S, with a wall thickness of 0.31 inches) from the LNG storage tank, three 16-inch LNG loading arms, one 16-inch vapor return arm, one 8-inch LNG loading arm with piggyback 6-inch vapor return line for loading LNG barges, electro-hydraulic control system, hydraulic quick connect/disconnect system, hydraulic emergency release system, swivel

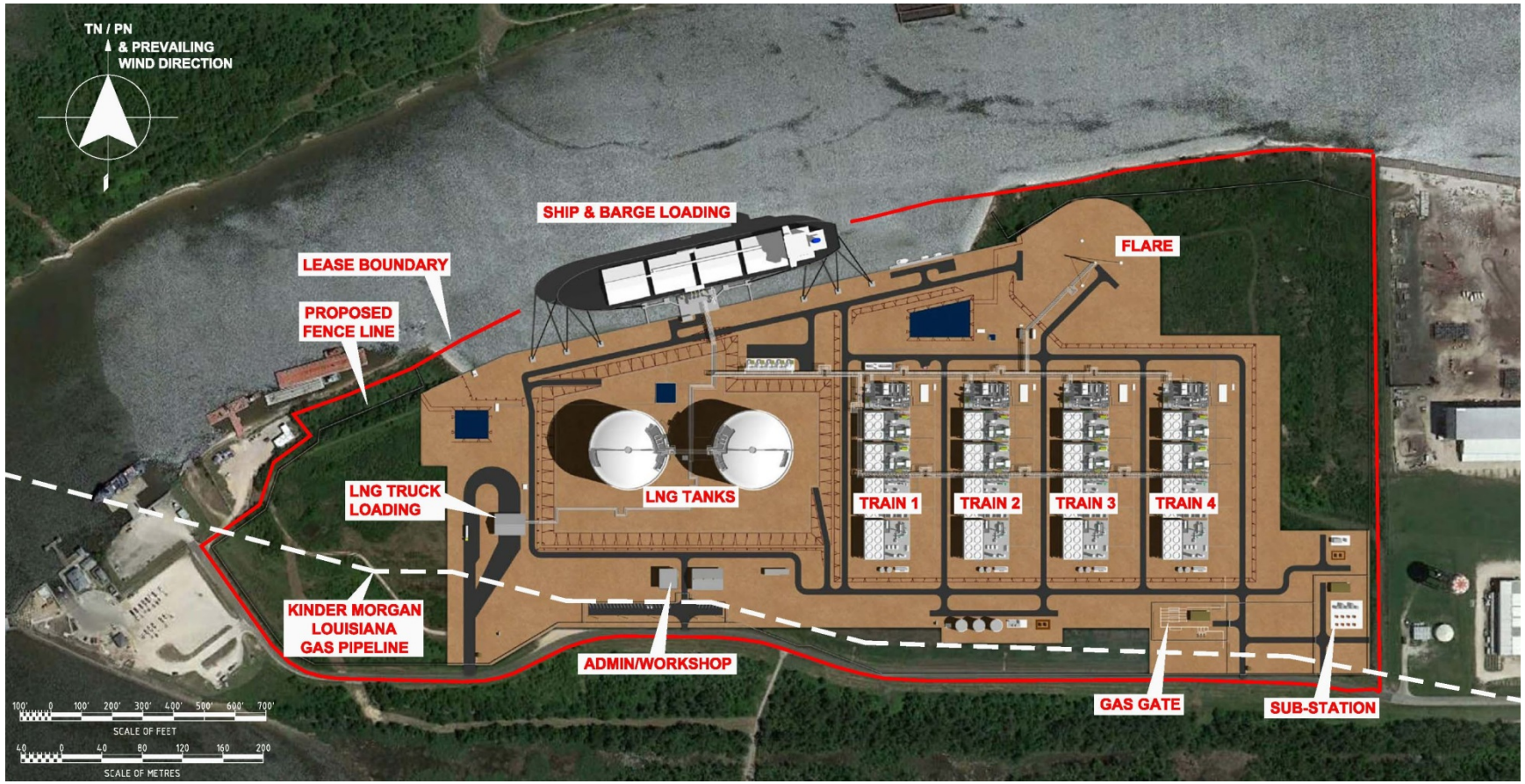


Figure 9.1-3 Artist's Rendering of Proposed Facility Layout

joints with nitrogen gas purge; mechanical locking devices, drain connections, and berthing dolphins, mooring dolphins, tug mooring, and walkways. For additional information on the Magnolia LNG marine facilities, refer to RR 1 "General Project Description" (see Section 1.5.4.2 "LNG Vessel Loading Facility Construction").

Berthing and mooring configurations would be able to accommodate LNG vessels with capacities between 125,000 and 218,000 m^3 (LNG-Flex), as well as LNG barges with capacities of approximately 15,000 m^3. It is currently projected that, on average, one to two LNG carriers per week and an additional one to two LNG barges per week would make port calls at the Project terminal when operating at full plant capacity. Current projections of port call frequency are based on the maximum nominal LNG output of 8.0 mtpa and typical ship and barge sizes. The actual number of port calls per week will be determined by contracts that are subsequently executed and the capacity of the specific ships and barges used. The maximum number of vessel and barge transits per year will be determined by the U.S. Coast Guard as part of the Waterway Suitability Assessment process.

9.1.5 LNG Truck Loading

The Project would include facilities that allow a portion of the LNG to be loaded onto trucks for road distribution to LNG refueling stations in Louisiana and surrounding states. The LNG truck-loading area would include the following main facilities: cryogenic pipework (loading and vapor return) from the LNG storage tank(s) to the LNG truck-loading area; flexible cryogenic hoses (loading and vapor return) for filling; control panel; shelter; and a turning circle for LNG trucks. The capacity of the LNG trucks would be approximately 12,500 gallons (47 m^3) with a loading flow rate of approximately 265 gallons per minute (60 m^3 per hour). The anticipated volume of LNG to be delivered by truck once the Project is fully operational is about 2,461 m^3 per year (650,000 gallons per year).

It is currently projected that, on average, one truck would be loaded per week at the proposed facility when operating at full capacity and more LNG fueling stations become operational in Louisiana and neighboring states. Following the commissioning of the first two trains, Magnolia is initially projecting that their market share would allow for approximately 26 trucked cargos annually (12,500 gallons average per cargo) based on the existing LNG fueling stations currently in operation and projected to be constructed in Louisiana and Texas. As the market develops and more LNG refueling stations become operational, Magnolia would seek to increase market share, doubling the trucked cargos annually from the Magnolia LNG facility. For additional information, refer to RR 1, "General Project Description" (see Section 1.2, "Purpose and Need").

9.1.6 Feed Gas and Interconnect Pipeline

Feed gas would be transported to the site boundary via an existing 42-inch interstate gas pipeline owned and operated by Kinder Morgan Louisiana Pipeline (KMLP) that passes beneath the Project site near the southern boundary. The KMLP pipeline would be accessed within the Project site boundary. A short interconnect pipeline of approximately 75 feet to be located entirely within the Project site would tie-in the existing underground pipeline to the Gas Gate

Station. The Gas Gate Station would include an incoming interconnect pipeline, a filter/separator, custody transfer meter(s), a pressure regulator, an emergency shutdown (ESD) valve, and a gas analyzer. The short interconnect pipeline, the Gas Gate Station, the modification of certain existing KMLP delivery meter facilities to make them bidirectional, and the installation of new compression facilities near Eunice, Louisiana, will be built, owned, and operated by KMLP and, as such, will require a separate filing by KMLP with the FERC under Section 7(c) of the Natural Gas Act as explained in RR 1, Section 1.13, "Transportation of Feed Gas to the Magnolia LNG Project." A binding precedent agreement related to these facilities and up to 1.4 billion standard cubic feet per day of firm transportation on KMLP's pipeline was executed on January 28, 2014, between KMLP and Magnolia.

9.2 AIR QUALITY

9.2.1 Climate and Meteorology

The dispersion of air pollutants depends upon many factors, including meteorological conditions. All construction activities and operation of the Project would occur in southwestern Louisiana. Climate and meteorology data, normal and mean temperatures, humidity, precipitation, and winds were obtained from the National Oceanic and Atmospheric Administration (NOAA) Local Climatological Data product for Lake Charles, Louisiana. Modification of gas pipeline facilities owned by KMLP would occur in Acadia and Evangeline Parish. Climate and meteorological data associated with the facilities KMLP would construct and operate in order to deliver natural gas via its interstate pipeline to the Project site would be presented by KMLP, separately.

The Project area's general climate classification is humid subtropical with a strong maritime influence. The large of amount of water surface in the local area and proximity to the Gulf of Mexico produce the humid maritime conditions experienced in the area. The predominant wind direction is from the south for much of the year, which tends to subdue extreme summer heat and shorten the duration of winter cold outbreaks, but also increases relative humidity in the area. During winter months, the highest wind speeds occur with the wind direction being predominantly from the north.

January is typically the coolest month, followed by December and February; the months of June through September are the warmest (NOAA 2012). Precipitation is distributed fairly evenly throughout the year, but peaks in June and July. The area rarely receives snow; the annual normal is 0.1 inches with the maximum monthly being 4 inches which occurred in January 1973.

Normal annual average relative humidity is 79 percent. Humidity above 85 percent occurs very often overnight throughout the year. Climate normals are shown in Table 9.2-1.

Table 9.2-1 Baseline Climate Data (1981-2010) for Lake Charles, Louisiana

Month	Mean Maximum Temperature (°F)	Mean Minimum Temperature (°F)	Mean Daily Temperature (°F)	Mean Precipitation (in.)	Mean Wind Direction	Mean Wind Speed (mph)
January	60.8	42.1	51.4	5.23	360	8.8
February	64.1	44.7	54.4	3.46	360	9.2
March	71.2	51.3	61.2	3.66	170	9.0
April	78.1	58.8	68.5	3.33	190	8.9
May	84.4	66.2	75.3	5.20	190	7.8
June	89.3	72.1	80.8	6.85	190	6.7
July	91.0	74.2	82.7	5.63	210	5.5
August	91.4	73.7	82.6	4.86	190	5.4
September	87.8	69.1	78.4	5.26	50	6.6
October	80.7	58.6	69.7	4.90	50	7.3
November	71.2	50.1	60.7	4.43	360	8.0
December	63.6	44.0	53.8	4.68	360	8.6
Annual	77.8	58.7	68.3	57.49	190	7.7

Source: NOAA 2012.

9.2.2 National and Louisiana Ambient Air Quality Standards

The Clean Air Act (CAA) of 1970, 42 U.S.C. 7401 *et seq.*, amended in 1977 and 1990, is the primary federal statute governing air pollution. The CAA designates six pollutants as criteria pollutants, for which National Ambient Air Quality Standards (NAAQS) have been promulgated to protect public health and welfare. The six criteria pollutants are particulate matter (including PM_{10} and $PM_{2.5}$), carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), lead (Pb), and ground-level ozone (O_3). Volatile organic compounds (VOCs) are not considered a criteria pollutant, but are evaluated as precursors to ground-level ozone formation. Primary and secondary standards are in place for criteria pollutants. Primary standards are designed to protect human health; secondary standards focus on protection of plant and animal life, buildings and other items in the public interest. Louisiana has adopted the Federal primary and secondary NAAQS. The standards are shown in Table 9.2-2.

Louisiana has also promulgated ambient air quality standards for toxic air pollutants (TAPs) in Title 33, Environmental Quality, Part III, Air, Chapter 51 (Louisiana Administrative Code [LAC] 33:III.51). The ambient air standards are applied in modeling evaluation of TAPs that exceed minimum emission rates only at major sources. A major source is defined in LAC 33:III.5103 as one that emits 10 tons per year (tpy) of a single TAP or 25 tpy of any combination of TAPs.

9.2.3 Existing Air Quality and Attainment Status

Calendar years 2010 to 2012 air quality monitoring data from the U.S. Environmental Protection Agency (USEPA) AirsData monitor values database was reviewed to characterize background air quality for regulated criteria pollutants (USEPA 2012). Air quality monitoring stations in proximity to the Project area were considered for obtaining monitored values. Because not all pollutants are monitored at each site, multiple monitoring sites are needed to characterize air quality. Four monitor sites were selected (Westlake, Lake Charles and Lafayette, Louisiana, and Jefferson County, Texas).

These monitoring sites have been established by the respective state air quality agencies (LDEQ for the Louisiana sites and TCEQ for Jefferson County, Texas) for monitoring population exposure to air pollutants. The sites are part of the State and Local Air Monitoring Stations (SLAMS), a national network established by the USEPA and implemented by state agencies to carry out the USEPA's monitoring requirements. States must follow strict guidelines with respect to siting the monitoring station and the type of equipment to be used, calibration frequency, and data recovery (e.g., monitoring stations must achieve a specific percent of valid data). These stations are sited in accordance with USEPA requirements.

The Westlake monitor site is 10.7 miles (17.2 kilometers [km]) north of the Project site. The Lake Charles site is 6.7 miles (10.8 km) northeast of the Project site. The Jefferson County (Nederland High School) monitoring site for CO is 43.7 miles (70 km) to the west. Terrain is flat at the monitoring sites and land use consists of a mix of residential, commercial, and industrial uses, similar to the proposed Project location. The Lafayette Parish (Cajundome) monitoring site for PM_{10} is 75 miles (121 km), east of the Project site, is characterized by flat terrain that is more urbanized than the Project site. PM_{10} concentrations measured in Lafayette Parish are conservative (i.e., likely higher) values than for the Project site due to the higher degree of urbanization in Lafayette Parish resulting in increased generation of PM_{10} emissions.

Background concentration data and primary NAAQS are shown in Table 9.2-2. Note that for lead, the USEPA data set does not currently provide the rolling three-month maximum statistic over the required three-year period; therefore no data are available for comparison to the NAAQS for lead at this time. In addition, monitoring for PM_{10} in Lake Charles ceased in 1997 and is currently not performed in southwestern Louisiana or nearby areas of Texas; therefore, data from the closest available monitor were used. Monitoring ceased in Lake Charles due to continued demonstration of compliance with the NAAQS for PM_{10} and a shift in priority of labor and funding resources to monitoring ambient concentrations of $PM_{2.5}$.

Table 9.2-2 Background Ambient Air Quality (2010 to 2012) and Ambient Air Quality Standards

Air Pollutant	Averaging Period	Statistic	Monitor Values [(a)]	Monitoring Site (Site ID)	Primary NAAQS [(b)]
Sulfur Dioxide (SO_2)	1-Hour	99th Percentile of daily 1-hour maximum averaged over 3 years	38 ppb	Westlake LA (220190008)	75 ppb
Carbon Monoxide (CO)	1-hour	Not to be exceeded more than once per year	1 ppm	Jefferson Co. TX (482451035)	35 ppm
	8-hour		0.5 ppm	Jefferson Co. TX (482451035)	9 ppm
Nitrogen Dioxide (NO_2)	1-Hour	98th percentile averaged over 3 years	32 ppb	Westlake LA (220190008)	100 ppb
	Annual	Annual mean	15.6 ppb	Westlake LA (220190008)	53 ppb
Ozone (O_3)	8-Hour	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years	69 ppb	Westlake LA (220190008)	75 ppb
Particulate Matter of 10 microns in diameter or less (PM_{10})	24-Hour	Not to be exceeded more than once per year on average over 3 years	84 (1st max) 73 (2nd max) $\mu g/m^3$ [(c)]	Lafayette LA (220550007)	150 $\mu g/m^3$
Particulate Matter of less than 2.5 microns in diameter ($PM_{2.5}$)	24-Hour	98th percentile averaged over 3 years	20.7 $\mu g/m^3$	Lake Charles LA (220190010)	35 $\mu g/m^3$
	Annual	Annual mean averaged over 3 years	8.9 $\mu g/m^3$	Lake Charles LA (220190010)	12 $\mu g/m^3$
Lead (Pb)	Rolling 3-month	Not to be exceeded	(d)	-	0.15 $\mu g/m^3$

Source: USEPA AirsDatabase 2013.

Notes:

(a) Monitor value shown matches the statistic of the NAAQS. 3 year averages are formed from 2010 to 2012 data. For CO, value shown is maximum 2nd highest occurring in the 2010 to 2012 period. For NO2 annual, value shown is highest annual mean from the period 2010 to 2012.

(b) Secondary standards are promulgated for some pollutants and are generally the same as or less stringent than primary standards.

(c) Values shown are maximum 1st high and maximum 2nd high from 2010 to 2012 data. Monitoring for PM_{10} 24-hour is not performed in south-western Louisiana. Closest monitoring site is Lafayette, approximately 75 miles east of Magnolia.

(d) Monitoring for lead is not performed in south-western Louisiana. Closest historical monitoring site is in Beaumont, Texas. Historical data at that location have shown compliance with the NAAQS.

Key:

$\mu g/m^3$ = micrograms per cubic meter.

NAAQS = National Ambient Air Quality Standards.

ppb = parts per billion.

ppm = parts per million.

Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants, including an attainment designation for the 8-hour ozone NAAQS granted on June 15, 2004. Due to a previous marginal ozone nonattainment designation for the now revoked 1-hour ozone NAAQS, Calcasieu Parish submitted, received USEPA approval on, and implemented a maintenance plan for the revoked 1-hour ozone NAAQS. According to Section 110(a)(1) of the CAA and guidance issued by the USEPA on May 20, 2005 (USEPA 2005), at the time areas designated attainment for the 8-hour ozone NAAQS that are attainment for the 1-hour ozone NAAQS with a maintenance plan in place must develop a revised 10-year maintenance plan under Section 110(a)(1) of the CAA. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA was submitted, approved by the USEPA, and has been in place since 2004, with its 10-year period ending in December 31, 2014. At the end of the 10-year maintenance plan period, a second 10-year plan is not required (see item 9 in USEPA 2005). Contingency measures in the existing approved 110(a)(1) maintenance plan remain in effect and these measures may be triggered if Calcasieu Parish exceeds the 8-hour ozone standard after December 31, 2014. Finally, a Section 110(a)(1) maintenance plan is not subject to any conformity obligations (USEPA 2005).

In addition, there are no nonattainment or maintenance areas through which LNG vessels would pass while transiting the Calcasieu River in route to the Gulf of Mexico. Once in the Gulf of Mexico, they would remain away from shore areas and not pass through nonattainment or maintenance areas.

9.2.4 Applicable Regulations and Permitting

This section summarizes the federal regulatory requirements for greenhouse gases (GHGs), Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Title V Operating Permits. Applicable Louisiana air quality regulations also are summarized.

9.2.4.1 Federal Regulations

New Source Review

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the CAA. NSR must be addressed before construction can begin on new major sources or major modifications to existing major sources. The PSD program is the NSR permitting program for sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Emission source thresholds for nonattainment areas are lower than the emission source thresholds for attainment areas. The Project location is unclassifiable/attainment and, therefore, is compared to attainment area major source NSR thresholds.

The major source attainment area NSR thresholds are either 100 tpy or 250 tpy. The 100 tpy threshold applies only to 28 distinct source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 source categories; therefore, the applicable major source threshold is 250 tpy per criteria pollutant. Estimated operational emissions would be above 250 tpy for NO_X and CO (see Section 9.2.6.1, "Emission Estimates"); therefore, the Project is subject to major source NSR permitting. Once a facility triggers PSD due to one or more pollutants above 250 tpy, other air pollutants that exceed significant emission rates (as defined within PSD regulations) would be included within the PSD review. Table 9.2-3 provides a comparison of facility emissions (including only emissions subject to permitting) to PSD significant emission rates. This table also indicates the air pollutants included in the PSD review.

Table 9.2-3 Comparison of Facility Emissions to PSD Significant Emission Rates

Air Pollutant	Total Facility Emissions (tons per year)	PSD Significant Emission Rates (tons per year)	Subject to PSD?
Nitrogen Oxides (NO_X)	1,153.55	40	Yes
Carbon Monoxide (CO)	804.04	100	Yes
Volatile Organic Compounds (VOCs)	68.91	40	Yes
Particulate Matter (PM)	87.88	25	Yes
Particulate Matter 10 microns or less in diameter (PM_{10})	87.82	15	Yes
Particulate Matter less than 2.5 microns in diameter ($PM_{2.5}$)	87.78	10	Yes
Sulfur Dioxide (SO_2)	133.80	40	Yes
Hydrogen Sulfide (H_2S)	3.83	10	No
Total Reduced Sulfur Compounds (including H_2S)	3.83	10	No
Greenhouse Gases (GHGs; as Carbon Dioxide Equivalents [CO_2e])	2,114,530.54	75,000	Yes

Greenhouse Gas Mandatory Reporting Rule and Tailoring Rule

The USEPA has promulgated rules requiring monitoring, reporting, and recordkeeping for GHGs that began in calendar year 2010. The final mandatory reporting rule was published in the *Federal Register*, at 74 Fed. Reg. 56,260 (Oct. 30, 2009). A facility is required to report its GHG emissions if its aggregate maximum rated heat input from all combustion sources is greater than 30 million metric British thermal units per hour (MMBtu/hr) and the facility emits more than 25,000 metric tpy of carbon dioxide equivalent (CO_2e). Magnolia would be required to report GHG emissions since the maximum heat input from all sources would be above 30 MMBtu/hr and annual emissions of GHGs would be above 25,000 metric tpy.

The USEPA also has promulgated the PSD and Title V Greenhouse Gas Tailoring Rule (*see* 75 Fed. Reg. 31,514 [June 3, 2010]). The Rule was phased-in using two steps. The first phase-in step of the tailoring rule began on January 2, 2011, and the second phase-in became effective July 1, 2011. New sources and existing sources not previously subject to Title V that emit at least 100,000 tpy CO_2e became subject to PSD and Title V requirements. Also, sources that have a potential to emit (PTE) of at least 100,000 tpy CO_2e and that undertake a modification that increases net emissions of GHGs by 75,000 tpy CO_2e will be subject to PSD requirements. Estimated PTE for GHGs for the Project is above 100,000 tpy CO_2e, therefore the Project is subject to PSD review for GHG.

New Source Performance Standards

NSPS regulations are issued for categories of sources that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The standards apply to new stationary sources of emissions, i.e., sources whose construction, reconstruction, or modification began after a standard for those sources was proposed. When an NSPS applies at a facility, the facility must also comply with NSPS Subpart A (General Provisions).

NSPS Subpart Dc (Standards of Performance for Small Industrial, Commercial and Institutional Steam Generating Units) is also promulgated by the USEPA in 40 CFR Part 60. This NSPS applies to steam-generating units constructed after July 9, 1989, and that have maximum heat input capacity of 100 million British thermal units (MMBtu) per hour or less. The auxiliary boilers that are part of each liquefaction train are subject to NSPS Subpart Dc because they would be constructed after the applicability date and would have maximum heat input capacity of less than 100 MMBtu/hr.

NSPS Subpart IIII (Standards of Performance for Compression Ignition Internal Combustion Engines) for various engine sizes and types has been promulgated by the USEPA in 40 CFR Part 60. These standards implement Section 111(b) of the CAA. Stationary compression ignition internal combustion engines for use with emergency electric generators and firewater pumps are proposed as part of this project, therefore NSPS Subpart IIII applies.

NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) regulates emissions of NO_X and SO_2 from combustion turbines. The applicability thresholds are a heat input rating (based on the higher heating value of the fuel) at peak load equal to or greater than 10 MMBtu/hour and manufactured after February 18, 2005. Because the proposed turbines are above these applicability thresholds, NSPS Subpart KKKK will apply.

National Emission Standards for Hazardous Air Pollutants Applicability

Section 112 of the CAA authorized the USEPA to develop technology-based standards that apply to specific categories of stationary sources that emit hazardous air pollutants (HAPs). These standards are referred to as National Emission Standards for Hazardous Air Pollutants (NESHAP) and are found in 40 CFR 61 and 40 CFR 63. NESHAP can apply to major and/or

area (minor) sources of HAPs. The USEPA develops national priorities for NESHAPs that focus on significant environmental risks and noncompliance patterns.

For the Magnolia LNG facility, the annual emissions of each individual HAP would be less than 10 tpy and the total annual emissions of all HAPs would be less than 25 tpy. Therefore, the facility would be an area (minor) source of HAPs.

NESHAP Subpart YYYY regulates HAP emissions from stationary combustion turbines located at major emission sources. Since the Project would not be a major source of HAPs, NESHAP Subpart YYYY does not apply to the proposed gas turbines.

NESHAP for Reciprocating Internal Combustion Engines (RICE) amendments were promulgated under 40 CFR Part 63, Subpart ZZZZ, by the USEPA. The original major source NESHAP for RICE was amended to include those with a site rating of 500 horsepower or less located at major sources, and new and reconstructed stationary RICE located at area sources. Based on the potential to emit for HAPs, Magnolia would be an area source. The RICE proposed for this Project includes the engines used for the emergency generators, the fire water pumps, and the deluge pumps. Therefore Subpart ZZZZ is applicable. In accordance with 40 CFR 63.6590(c), compliance with Subpart ZZZZ will be achieved through compliance with NSPS Subpart IIII.

The USEPA finalized NESHAPs Subpart DDDDD for Major Sources: Industrial-Commercial-Institutional Boilers and Subpart JJJJJJ for Area Sources: Industrial-Commercial-Institutional Boilers on February 1, 2013. Subpart DDDDD applies to facilities emitting 10 tpy or more of an individual HAP or 25 tons or more of total HAPs. Subpart JJJJJJ applies to sources emitting below the major source thresholds that fire coal, oil, or biomass; Subpart JJJJJJ does not apply to gas-fired boilers. Emission estimates for HAPs (see Section 9.2.6.1, "Emission Estimates") indicate that the facility would be considered an area source for HAPs, however the auxiliary boilers meet the definition of gas-fired boilers in 40 CFR 63.11237 and thus are not subject to Subpart JJJJJJ.

General Conformity

Section 176 of the 1990 CAA Amendments required the USEPA to promulgate rules to ensure federal actions conform to the appropriate State Implementation Plan (SIP). These rules, known together as the General Conformity Rule (40 CFR 51.850-.860 and 40 CFR 93.150-.160), require any federal agency responsible for an action in a non-attainment or maintenance area for any criteria pollutant to determine if the action conforms to the applicable SIP or is exempt from the General Conformity Rule requirements. This means federally supported or funded activities will not:

- Cause or contribute to any new air quality standard violation;
- Increase the frequency or severity of any existing standard violation; or
- Delay the timely attainment of any standard, interim emission reduction or other milestone.

The USEPA amended the General Conformity Rule in 2010 (*see* 75 Fed. Reg. 17,253 [Apr. 5, 2010]). Included in the amendment is the exclusion of emissions regulated by any permit issued under minor and major NSR from a General Conformity applicability analysis. Previously, only major NSR permit emissions were excluded.

A conformity determination is required for each pollutant where the total of direct and indirect emissions caused by a federal action (such as a FERC action) would equal or exceed de-minimis levels as specified in 40 CFR Part 93.153 with the exceptions specified in 40 CFR Part 51.853(c), (d), or (e). Conformity evaluations are not required for areas that are in attainment for NAAQS.

Calcasieu Parish is designated as attainment for all pollutants. Other parishes or counties through which marine vessels associated with the Project may pass also are designated as attainment. General Conformity does not apply in attainment areas. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA is in place, with its 10-year period ending on December 31, 2014. However, this maintenance plan is not subject to any conformity obligations (USEPA 2005). Therefore no further analysis is required under General Conformity.

9.2.4.2 Louisiana Regulations

State air quality rules govern the issuance of air permits for construction and operation of a stationary emission source. For larger facilities subject to major NSR, review and approval at the federal level may be required. For new facilities, classification as a minor or major source depends on the quantity of potential emissions and the existing air quality designation of the project location. Louisiana's state air quality regulations are found in LAC, Title 33, Part III (Air).

9.2.4.3 Air Permitting Requirements

The Louisiana Department of Environmental Quality (LDEQ) administers the air permit programs for the Project. A new facility must apply for and obtain an air quality permit prior to commencing construction. After the Project completes construction and commences operation, the Project would be governed by an operating permit. The USEPA may review a project's air permit application if the PTE for the proposed project exceeds PSD major source thresholds. These thresholds are listed in Title 40 CFR §52.21(b)(1)(i).

Title V Operating Permit Applicability

The federal Title V operating permit program is delegated to the LDEQ. The Louisiana Air Operating Permit program is codified in LDEQ Title 33 Environmental Quality, Part III Air, Chapter 3 and 5. The major source threshold for the Title V operating permit program is 100 tpy for criteria pollutants, 10 tpy for individual HAPs, and 25 tpy for any combination of HAPs. Estimated site-wide PTE emissions for NO_X, CO, VOC, and HAPs for the Project are above major stationary source Title V thresholds therefore, the Project is subject to the Title V Operating Permit program.

Class I Areas

Two factors determine potential effects on federal Class I areas: magnitude of emissions and distance to the Class I area. After construction of the Project, the PTE, with controls, is above 250 tpy for all criteria pollutants; therefore the facility is a major emission source of criteria pollutants under NSR PSD regulations. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, a separation distance greater than 300 kilometers between an emission source and a Class I area preclude the need for further Class I air quality analyses.

9.2.5 Air Pollutant Emissions – Construction

Construction activities would result in temporary, localized emissions that would last for the duration of the construction period. Project components would be constructed during various months beginning in mid-2015 (July 1, 2015) with proposed facilities placed into service by June 2018 as shown on the Project schedule included in RR 1, "General Project Description" (see Appendix 1.E, "Project Schedule"). Emissions from construction are not expected to result in a violation of any applicable ambient air quality standard; construction equipment would be operated on an as-needed basis during daylight hours only.

9.2.5.1 Construction Emissions – Methodology

An inventory of non-road equipment, vessels, on-road vehicles, off-road vehicles, and expected activity levels (either hours of operation or miles travelled) were developed based on expected duration of construction at the site. The level of activity for each piece of construction equipment was combined with emission factors obtained from various sources (as described below) resulting in estimates of annual construction emissions for each year of construction.

The construction schedule and anticipated tasks are defined in detail in RR 1, "General Project Description." For the purpose of estimating construction emissions, construction is divided into six phases consisting of the following:

- **Site Preparation**, consisting of site clearing by removing debris, followed by stripping/grubbing topsoil (stockpiled on-site), cut-fill and rough grading operations, construction of drainage swales and the short (approximately 1,500 feet) heavy-haul road from the construction workspace immediately east of the Project site and preparation for foundations. Equipment used in this phase includes dump trucks, bulldozers, backhoes, trackhoes and drum rollers. See Appendix 9.A, Phase I for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **LNG Storage Tanks**, consisting of foundation construction using concrete piles driven by hydraulic pile drivers and site-erected tank construction. See Appendix 9.A, Phase II for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **Balance of Plant**, consisting primarily of foundation construction for the LNG trains, receipt of the LNG train modules at the temporary work yard, transport from the work yard to the Project site using heavy crawlers, assembling each train, and completion of other plant equipment such as emergency water pumps, site buildings, onshore components of the LNG vessel loading facility, among others. This phase includes use of pile drivers for the LNG vessel loading facility as well pile-driving required for the LNG trains, storage tanks, and other site structures. See Appendix 9.A, Phase III for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **Architectural/Building Construction**, during which on-site buildings and other architectural components would be constructed in 2016 and 2017 using the equipment type and quantity identified in Appendix 9.A, Phase IV.

- **Marine Work**, consisting of construction of the LNG vessel loading facility, including the berthing and waterway access area. The berthing and waterway access area would be constructed using a combination of onshore excavation (using backhoe and trackhoe equipment) and dredging using a hydraulic cutterhead suction dredge mounted on a self-propelled vessel. Dredging emissions are included in this phase. Bulkhead construction would consist of pile-driving steel sheet at the ends of the berthing basin and armoring with rock at the base of the bulkhead; breasting dolphins would be constructed by pile-driving 8-foot-diameter steel pilings into competent foundation soils. See Appendix 9.A, Phase V for equipment lists, quantity, utilization, emission factors, horsepower, and fuel type.

- **Miscellaneous Construction**, consisting of equipment not tied to a specific task but that would be used for general construction activities throughout the duration of construction. Equipment would consist of pickup trucks/vans, water trucks, forklifts and utility carts. See Appendix 9.A, Phase VI for equipment details.

Construction materials would be delivered to the site primarily by barge. Unloading would occur at the existing construction yard immediately east of the Project site, at the Dynamic Industries, Inc. facilities. A total of 50 barge loadings were used to estimate emissions associated with construction material delivery. In addition, large quantities of concrete would be used to construct the Project. Cement would be sourced from existing concrete plants in the area within 3 to 5 miles of the Project site. Emissions associated with truck transport of concrete are included in the construction emission estimate in several of the construction phases (LNG storage tanks, balance of plant and architectural buildings).

Emission factors for non-road on-land equipment, including off-road trucks, were obtained from runs of the USEPA NONROAD Emission Factor Model, Version 2008a (USEPA 2008) for Calcasieu Parish for the construction years 2015, 2016, and 2017.

Two types of marine vessels would be used during construction. Tugboats would be used for barge delivery of material required to construct the Project. Dredging of the berthing and waterway access areas would be accomplished using a typical medium-sized (approximately 1,500 horsepower) dredging vessel. Emission estimates for construction activities are based on

the anticipated duration of use of each vessel type during the construction period, the vessels' engine characteristics and duty cycles, and emission factors from the USEPA guidance document "Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories" (ICF International 2009). Since vessel contractors have not yet been selected for the Project, vessel emission Tiers are not known; thus, Tier 0 vessels were assumed for emission estimation purposes.

On-road vehicle emission factors were determined using the USEPA Motor Vehicle Emission Simulator (MOVES) 2010b mobile source emission factor model. The model was run for each year of construction activity using the model's internal mobile source database tailored to Calcasieu Parish. Emission factors for passenger cars and trucks (sport utility vehicles) and short-haul and long-haul trucks were produced. These factors (in grams per mile of vehicle activity) were combined with estimates of miles travelled by cars and trucks to determine annual on-road emissions from construction activities.

A spreadsheet-based emission estimate procedure was used to combine the construction schedule, inventory of vessels/equipment/on-road vehicle/off-road vehicle types, quantity and duration of use, and emission factors to determine total Project construction emissions. Detailed calculations are provided in Appendix 9.A.

Fugitive dust emission levels would vary in relation to moisture content, composition, activity level and volume of soils during construction. Fugitive dust would be produced primarily during the initial phase of preparing the site for construction of the Project when the site would be cleared of debris and leveled using cut-and-fill techniques and graded. In addition, approximately 131,200 cubic yards of soil from upland areas would be excavated and placed on-site. Existing off-site paved roads would be used to access the Project location with no new road construction or modifications required for Project purposes. There would be limited unpaved road travel on-site due to the compact footprint of the construction site, short distance (less than 1,500 feet) of the heavy-haul road, and slow speeds used to transport Project components and other raw materials from the adjacent construction yard to the Project site (utilizing self-propelled modular transporters for large Project components).

The fugitive emission estimate consists of contributions from general site construction work based on acres of activity, earth-moving fugitive dust emissions based on quantity of soil moved, and unpaved road travel based on weight of vehicles. Magnolia would implement dust control measures as necessary during certain construction activities, such as transporting soil or rock, trenching, and use of access roads; these measures would be specified in a control plan. Fugitive dust emissions associated with construction would not contribute to degradation of NAAQS.

9.2.5.2 Construction Emissions Results

Construction equipment emissions and fugitive dust emissions are summarized in Table 9.2-4.

Table 9.2-4 Total Construction Emissions By Year

Activity	VOC	NO_X	PM_{10} and $PM_{2.5}$	CO	SO_2	CO_2e
	Emissions (tons)					
Calendar Year 2015						
Site Preparation	0.6	6.4	0.7/0.7	3.1	0.3	1,817
LNG Tank Construction	1.0	10.1	1.0/1.0	13	0.5	2,599
Balance of Plant	0.5	5.3	0.5/0.5	5.2	0.3	1,435
Architectural	0.0	0.0	0.0	0.0	0.0	0.0
Marine (dock, jetty, dredging)	0.4	11.5	0.4/0.4	3.0	1.1	954
Material Transport via Tug/Barge	0.0	0.0	0.0	0.0	0.0	0.0
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.6	0.1/0.1	2.4	0.1	225
Construction Mobile Sources (worker commutes)	0.0	0.1	0.0/0.0	1.6	0.0	238
Fugitive dust	--	--	14.9/1.5	--	--	--
Total	**2.6**	**34**	**17.6/4**	**27**	**2.2**	**7,268**
Calendar Year 2016						
Site Preparation	0.0	0.0	0.0	0.0	0.0	0.0
LNG Tank Construction	4.1	25	2.9/2.9	93	1.5	8,739
Balance of Plant	0.4	2.9	0.4/0.3	5.8	0.2	1,010
Architectural	1.4	3.7	0.2/0.2	49	0.2	856
Marine (dock, jetty, dredging)	1.2	12	0.8/0.8	31	1.0	2,523
Material Transport via Tug/Barge	0.5	26	0.6/0.6	5.0	2.6	1,385
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.8	0.1/0.1	0.5	0.1	427
Construction Mobile Sources (worker commutes)	0.0	0.2	0.0/0.0	2.8	0.0	408
Fugitive dust	--	--	14.3/1.4	--	--	--
Total	**7.8**	**71**	**19.3/6.2**	**187**	**5.6**	**15,348**
Calendar Year 2017						
Site Preparation	0.0	0.0	0.0	0.0	0.0	0.0
LNG Tank Construction	2.9	12	1.5/1.5	88	0.7	4,022
Balance of Plant	0.2	0.9	0.1/0.1	4.6	0.1	372
Architectural	1.2	2.6	0.2/0.1	46	0.1	654
Marine (dock, jetty, dredging)	0.4	1.7	0.2/0.2	12	0.1	858
Material Transport via Tug/Barge	0.0	0.0	0.0	0.0	0.0	0.0
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.6	0.1/0.1	0.4	0.1	396
Construction Mobile Sources (worker commutes)	0.0	0.2	0.0/0.0	2.8	0.0	408
Fugitive dust	--	--	14.3/1.4	--	--	--
Total	**4.8**	**18**	**16.4/3.4**	**154**	**1.1**	**6,710**

Potential projects in proximity to the Project include three proposed projects within 0.5 mile of the Project site. These projects are G2X Energy, the Trunkline LNG, LLC, Lake Charles Export Terminal (Trunkline LNG), and the Lake Charles Fisheries Research Center. Two of these projects, G2X Energy and Trunkline LNG, anticipate a construction period beginning in 2014 and ending in 2017 (see Table 1.9-1 in RR 1, "General Project Description," Section 1.9 "Cumulative Impact Analysis"). This construction period would overlap with the Project's construction period of mid-2015 through 2017. The construction of the Lake Charles Fisheries Research Center would not overlap with the construction of the Magnolia LNG Project and the construction schedule will not be established until after the facility is designed; therefore, it is not possible to speculate on its potential to contribute to a cumulative impact. For additional information, please refer to Section 9.4 of this resource report.[1]

9.2.5.3 Construction Emissions – General Conformity

As noted in Section 9.2.4.1, "Federal Regulations," Calcasieu Parish and surrounding parishes are designated as in attainment with the NAAQS. General conformity does not apply to attainment area emissions. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA is in place, with its 10-year period ending in June 2014. However, this maintenance plan is not subject to any conformity obligations (USEPA 2005). Therefore General Conformity does not apply to the Project's construction emissions since construction emissions would occur only in Calcasieu Parish.

9.2.6 Air Pollutant Emissions – Operation

Each of the four liquefaction trains would consist of the following emission sources:

- Two General Electric PGT25+G4 dry low NO_X gas turbines
- One auxiliary boiler
- One thermal oxidizer to treat emissions from the amine unit
- One ammonia vent
- Fugitive emissions from pipe flanges, valves and valve stems

The emission sources associated with each liquefaction train would operate continuously; the air permit application for the facility will request full-year operation for these sources.

[1] On February 6, 2014, a meeting was held with Jason Duet and Craig Gothreaux with the Louisiana Department of Wildlife and Fisheries (LDWF) regarding the Fisheries Research Center to gather additional information about the proposed facility, including the timing for its construction. The LDWF anticipates that it will be at least four years before ground is broken on the research center. So far, the LDWF has completed a high-level concept study of the center, started an environmental assessment of the project, and initiated coordination efforts with state and federal regulatory agencies to determine what permits are required. During the meeting, it was stated that funding for the project came from the Louisiana Oil Spill Coordinator's office as an early Natural Resources Damage Assessment (NRDA) project (paid for through early NRDA funding provided by BP) and they would turn the project over to the State Office of Facility Planning. Facility Planning would then issue the Request for Proposal for the design of the facility; once the facility is designed, they would issue bids for construction.

The facility also would contain the following emission sources:

- One cold gas flare for treating low temperature gases
- One warm gas flare for treating warm and high temperature process gases
- One diesel engine-driven emergency electric generator (1,000 kilowatts)
- Two diesel engine-driven emergency firewater pumps
- Two diesel engine-driven deluge water pumps
- LNG tanker vessels and attendant tugboats
- Tugboats/LNG barges
- Miscellaneous mobile sources associated with facility operations, including worker commuting vehicles and potential truck transport of LNG to regional highway LNG refueling sites

The additional facility emission sources listed above would operate on an intermittent or as-needed basis. The air permit application will request operating restrictions for the flares and diesel-engine generators and pumps to limit emissions. All diesel engine-driven equipment is provided solely for standby/emergency use. Mobile source emissions are not subject to air permitting in the state of Louisiana.

During operation, there is a potential that fugitive emissions would be produced from pipe flanges and valves and other components in gas or liquid service. Emission factors combined with component counts for compressors, flanges, relief valves and other potential emission sources have been used to estimate fugitive emissions.

In addition to stationary sources, operation of the Project would produce emissions from mobile sources including LNG tanker vessels, tugboat emissions produced during barge transport of LNG to local distribution facilities, worker commuting emissions, and potentially on-road truck emissions if the truck LNG distribution capability is also built.

9.2.6.1 Emission Estimates

Emission estimates for Project operation are shown in Table 9.2-5. Detailed calculations are provided in Appendix 9.B, “Operational Emissions,” for each emission source. Appendix 9.B.1, Table 1 provides a facility-wide emission summary for all stationary and mobile sources. Appendix 9.B.1, Table 2 provides an emission summary for one LNG train (each LNG train is identical). Facility PTE is based on 8,760 hours of operation per year (full year), except that diesel engines powering the emergency generator, firewater pumps and deluge pumps are based on a limit of 500 hours per year and the warm and cold gas flares are based on 88 hours of operation treating gas releases with 8,760 hours per year of pilot gas operation. Mobile source emissions for LNG carriers and tugboats are based on frequency of operation to accommodate required LNG transport from the facility. Additional mobile source emissions include tugboat/barge LNG transport, operational worker commuting emissions and truck distribution of LNG.

Table 9.2-5 Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	Ammonia	HAPs	CO_2e
Gas Turbines (8)	1,019	621	1.0	74.2	74.2	42	--	11.2	1,330,992
Thermal Oxidizers (4)	31.5	26.4	132	4.2	4.2	3.1	--	0.08	550,372
Auxiliary Boiler (4)	81	82.2	0.4	7.5	7.5	7.5	--	1.6	204,422
Ammonia Vent (4)	--	--	--	--	--	--	5.8	--	--
Subtotal LNG Trains	**1,132**	**729**	**133**	**86**	**86**	**53**	**5.8**	**12.9**	**2,085,786**
Emergency Generator	3.6	1.9	0.0	0.09	0.08	0.35	--	0.0	385
Emergency Firewater Pumps (2)	1.2	1.0	0.0	0.04	0.04	0.1	--	0.0	198
Deluge Pumps (2)	4.2	2.3	0.0	0.1	0.1	0.4	--	0.0	198
Warm Gas Flare	8.3	45.2	0.0				--	0.1	16,559
Cold Gas Flare	4.5	24.6	0.0				--	0.0	8,975
Fugitive Emissions	--	--	--	--	--	14.7	1.54	0.28	2,222
Subtotal Other Sources	**21.8**	**75**	**0.0**	**0.2**	**0.2**	**15.6**	**1.54**	**0.4**	**28,537**
LNG Vessels and Tugboats	329	42	3	15	15	19			21,396
Worker Commuting	0.06	0.8	0.01	0.01	0.01	0.01		<0.01	110
Tug/Barge Distribution	66	6	0	4	4	4		n/a	3,383
Truck Distribution	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01		<0.01	2
Subtotal Mobile Source	**395**	**9**	**3**	**15**	**15**	**19**		**<0.01**	**24,889**
Facility Total	**1,549**	**853**	**136**	**101**	**101**	**88**	**7.3**	**13.3**	**2,139,212**

Gas Turbines

The gas turbines would drive the refrigeration compressors. A total of eight gas turbines (two per LNG train) would be used. Gas turbines would be aero-derivative units utilizing inlet air cooling to cool inlet air to 50°F when ambient air temperature is above 50°F; the turbines would have dry-low NO_X combustors. Gas turbines are expected to operate full-time throughout the year; current estimates of startup/shutdown requirements are two events per turbine per year. A gas turbine startup event would take 10 minutes from initiating startup to full gas turbine load. Annual emission estimates of NO_X and CO for gas turbine startup and shutdown events are based on manufacturers' estimated emissions per event of 2.5 pounds NO_X and 2.9 pounds CO and two startup events per turbine per year. Annual NO_X and CO emissions for startup would be 40 pounds and 46 pounds, respectively. A gas turbine shutdown event requires eight minutes to complete from full-load operation to shutdown. The manufacturer-estimated emissions per shutdown event are 2.2 pounds NO_X and 3.0 pounds CO. Based on two shutdown events per turbine per year, the resulting annual emissions would be 35.2 pounds NO_X and 48 pounds CO. Total startup and shutdown emissions would be 75 pounds NO_X and 94 pounds CO annually.

Appendix 9.B.1, Table 3 provides detailed calculations for the gas turbine operational emissions.

Thermal Oxidizer

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. A carbon dioxide (CO_2) waste gas stream containing hydrogen sulfide and benzene-toluene-ethylbenzene-xylene (BTEX) from the feed gas pre-treatment plant would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement allows the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Hydrogen sulfide is expected to fully oxidize to SO_2 with no emissions of sulfuric acid gas/mist anticipated.

Appendix 9.B.1, Tables 4 and 5 provide emission calculation details for the thermal oxidizer maximum and average conditions, respectively.

Auxiliary Boiler

The auxiliary boiler would combust a mixture of high British thermal unit (BTU) (feed gas and rich (heavy hydrocarbon) gas) and low BTU (holding and ship loading) fuel and inert gas (nitrogen) using two low NO_X burners, one for low BTU gas streams and one for high BTU gas streams. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has been estimated based on preliminary process and vessel loading waste gas production. There are four potential gas mixture scenarios that could be used as fuel in the auxiliary boiler. These cases and the expected percent of time during the year each gas mixture would be fired in the auxiliary boiler are:

- Average Feed Gas Base Case (84.74 MMBtu/hr Higher Heating Value [HHV]) – 90 percent
- Rich Feed Gas Case (99.0 MMBtu/hr HHV) – 3.52 percent
- Ship Loading Case (94.33 MMBtu/hr HHV) – 5.48 percent
- High Inert Feed Gas Case (82.87 MMBtu/hr HHV) – 1 percent

The emission totals for the auxiliary boiler in Table 9.2-5 reflect operation on the four fuel mixtures in the percentages of time shown above. The fuel gas stream burned in the auxiliary boiler may contain trace amounts of H_2S and BTEX from the CO_2 removal system. The estimated destruction efficiency for these HAPs in the combustion process is 99.99 percent. The emission totals for these HAPs, shown in Table 9.2-5, include the post-combustion quantities of these HAPs produced by burning feed gas and the waste gas stream.

Appendix 9.B.1, Tables 6 through 10 provide emission calculations details for the auxiliary boiler and gas mixtures.

Ammonia Vent

The ammonia vent provides for pressure relief from the ammonia chilling plant. It is anticipated that the vent would operate during normal facility operations to maintain system pressure. Appendix 9.B.1, Table 11 provides details for the ammonia vent emission estimate.

Flare System

The flare system would include two flares: one warm flare (or process flare) and one cold flare (or marine flare). The purpose of the flare system is to dispose of gas streams that are released during start-up, shutdown, plant upsets, and emergency conditions. The Project is being designed to avoid continuous flaring. Both flares would be located adjacent to one another on a common structure supported by a common guy wire system. The source of the pressure relief flows to the flares are gas discharges from relief valves, depressurizing valves and pressure control valves throughout the LNG plant that open automatically during abnormal conditions.

The warm flare would handle wet/warm relief gases. Prior to the flare, piping in the warm flare system would collect relief fluids from feed gas pretreatment and other above ambient temperature processes. A warm flare knockout drum would be used to collect water and any free liquids prior to reaching the flare stack.

The cold flare system would handle cold relief fluids and gases. The system is designed for gases and fluids lower than ambient temperature such as from the cold section mixed refrigerant, boil-off gas section, and LNG tank venting system. The relief fluids would pass through a cold flare knockout drum prior to the relief flow reaching the flare stack. The cold liquids collected in the knockout drum would gradually vaporize to the flare.

Appendix 9.B.1, Tables 12 and 13 provide details for the flare emission calculations.

Emergency Use Diesel Engines

Diesel engines would be provided to operate an emergency electrical generator (1,000 kilowatts [kW]), two fire water pumps (250 kW each), and two LNG tank deluge water pumps (600kW each). Emissions for each unit are based on a limit of 500 hours per year and low sulfur fuel (sulfur content of 15 ppm). Appendix 9.B.1, Tables 14, 15 and 16 provide details for the emergency use engines.

Fugitive Sources

During facility operation, there is a potential that fugitive emissions from gas and liquid process streams would be released. Potential fugitive emissions may come from piping components, such as from pipe flanges and valves and other components. Component counts for seven separate process streams at the facility were derived based on preliminary design information provided in conjunction with RR 13. Appendix 9.B.2, Tables 17 and 18 *[PRIVILEGED]* provide the estimated component counts, process stream gaseous constituents, and emission factors.

LNG Vessel and Tugboat Operations

The Project location is within the North American Emission Control Area (ECA) designated by the International Maritime Organization (IMO) through Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL). Key dates for the North American ECA are 2012 (1% sulfur fuel), 2015 (0.1% sulfur fuel) and 2016 (engine NOx emission after-treatment requirements).

LNG vessel emissions are based on a typical 175,000-cubic meter capacity vessel with compression ignition/electric propulsion. Propulsion emission factors are based on typical vessel engine manufacturer data for a Wartsila 50 DF operating primarily on natural gas with a small quantity of pilot marine gas oil fuel (0.1 percent sulfur). It is assumed the vessel primarily would operate on boil-off gas. Emissions are estimated for two trips per week over a round-trip distance from 12 miles offshore, up the Calcasieu River to the Project facility, maneuvering and docking, hoteling, and a return trip to a distance of 12 miles offshore. It is estimated that the vessel trip described above would require approximately 30 hours, with 18 hours included for hoteling while loading LNG at the Magnolia LNG facility. While hoteling during LNG loading, it is assumed the main propulsion engines would be shutdown with hoteling requirements supplied by auxiliary engines operating solely on marine gas oil. The LNG vessel emission estimate includes emissions from 6,000-horsepower tugboats that would assist the LNG vessel during the entire trip from/to the offshore location. Two tugboats would meet the LNG vessel offshore and escort it to a point approximately 3 miles from the Magnolia LNG terminal, where two additional tugs would join in assisting the LNG vessel to docking. While the LNG vessel is loading LNG, one tug would remain on standby, moored at the dock with only a hoteling generator in operation. The departure trip of the LNG vessel would essentially be a reverse of the inbound trip, applying the same number of tugboats. Appendix 9.B.1, Table 19 provides details for the LNG vessel/tugboats operations.

Tug/barge distribution of LNG is based on use of a large tug (approximately 6,000 horsepower) to push an empty barge to the Magnolia LNG loading dock and then push a barge loaded with LNG to a distribution point. The specific destinations for barge distribution of LNG are not known at this time, therefore the distance from the Project facility to the Gulf of Mexico and return (approximately 45 nautical miles round trip [approximately 50 statute miles]) was used in the emission estimate. An average speed of 3 knots results in an average round-trip duration of approximately 15 hours. Tug/barges are estimated to make up to two trips per week. Appendix 9.B.1, Table 19 shows emission estimate details associated with tug operation during barge loading, Table 20 shows the emission estimate details for the tug/barge transport.

On-Road Mobile Sources

On-road mobile source emissions (worker commuting and truck LNG distribution) are based on emission factors from a run of the USEPA MOVES model for Calcasieu Parish. Expected full-time employment data and potential residential locations from the Project traffic study were used to estimate annual round-trip miles travelled by workers commuting from the general area to the Project facility (40 directional trips by workers). The annual miles travelled were combined with emission factors from the USEPA MOVES model run to estimate annual

worker commute emissions. The round-trip distance for truck trips for distribution of LNG was based on the best potential route from the Project facility to Interstate 10 described in the traffic study (see Appendix 5.B in RR 5, "Socioeconomic") and assuming one truck trip per week. The potential number of truck trips is highly dependent on the development of local refueling stations for LNG or compressed natural gas vehicles. The annual miles travelled by the LNG distribution trucks were combined with heavy-duty truck emission factors from the MOVES run to estimate annual emissions. Appendix 9.B.1, Table 20 provides details for the emission estimate.

9.2.6.2 Ambient Impact Analysis

Magnolia is in the process of developing the ambient impact analysis. The ambient impact analysis will be based on proposed emission rates contained in the LDEQ air permit application. At this stage, emission rates in the LDEQ application are in draft form, thus the ambient impact analysis is preliminary only. The analysis will address the ambient impact of the proposed Project using dispersion modeling and photochemical grid modeling for ozone.

Magnolia has prepared two dispersion modeling protocols (see Appendix 9.C). The first protocol, dated January 15, 2014, describes modeling procedures to be used to support the LDEQ air permit application (Appendix 9.C.1). This protocol addresses modeling of the Project's stationary sources that are subject to air permit regulations and discusses procedures to be used if a cumulative impact analysis is required. For permitting purposes, if facility-only modeling results in modeled ambient concentrations above one or more significant impact levels (SILs), a cumulative source inventory will be developed and modeled in conjunction with the Project. The protocol received approval from the LDEQ on January 22, 2014.

For NEPA purposes, Magnolia prepared a second dispersion modeling protocol (Appendix 9.C.2). Magnolia has adapted the protocol approved by the LDEQ to include the LNG vessel and tugboat engine emissions in the modeling analysis and to address cumulative impacts in conjunction with nearby facilities.

Magnolia has prepared and submitted a photochemical modeling protocol to LDEQ and USEPA Region 6 (Appendix 9.C.3). Photochemical modeling is currently in process.

9.3 NOISE

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, and so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities.

The unit of noise measurement is a decibel (dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as dBA (A-weighted decibels; "A" indicates that the sound has been filtered to reduce the

strength of very low and very high frequency sounds, much as the human ear does). The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans perceive the 10 dBA increase as twice as loud, not 10 times louder.

Various descriptors that are commonly used to evaluate sound pressure levels over time include the following:

- Equivalent Sound Level, or L_{eq}, is the average of the sound energy over time. The L_{eq} integrates fluctuating sound levels over a period of time to express them as a steady-state sound level.

- Day-Night Average Sound Level, or Ldn, is equivalent to a 24-hour L_{eq}, but with a 10-dBA penalty added to nighttime noise levels (10:00 p.m. and 7:00 a.m.) to reflect the greater intrusiveness of noise experienced during this time.

- L_{max} is the maximum instantaneous noise level during a specific period of time.

9.3.1 Noise Regulations

The environmental sound level contributions from the proposed liquefaction equipment at the proposed Project facility are subject to the FERC noise regulation for new stations. Under these regulations, the noise attributable to any new natural gas compressor station must not exceed an Ldn of 55 dBA at any pre-existing noise sensitive area (NSA). In areas subject to steady noise levels throughout a 24-hour period, the Ldn noise level is about 6.4 dBA higher than the 24-hour L_{eq} because of the nighttime weighting factor. For a station that is operating continuously, an L_{eq} noise level of 48.6 dBA is equal to the FERC Ldn noise limit of 55 dBA. The FERC requirements stipulate that in addition to the Ldn 55 dBA limit, any applicable state or local noise regulations must be identified.

Calcasieu Parish noise regulations are contained in the Calcasieu Parish Police Jury Code of Ordinances, Chapter 18, Article VIII. However, these noise regulations do not prescribe numerical noise standards.

9.3.2 Existing Noise Levels

A noise survey was conducted by Ecology and Environment, Inc. beginning September 23 through September 25, 2013. The purpose of the survey was to characterize the existing noise environment around the proposed Project site. During the survey, continuous long-term average sound levels were measured statistically in consecutive 1-hour intervals at three NSAs as explained below. For a detailed description of methodology followed and conditions during the sound level measurements, see Section 4.0 of the noise survey report in Appendix 9.D.

The Project site is located in a mixed industrial and rural area with no residents within 0.5 mile of the site and approximately 30 residences within a 1-mile radius of the site. The noise sources in the area include wind, birds, insects, distant industrial facilities, boat traffic, and

vehicular traffic on local roads. Meteorological conditions during the measurements included clear to partly cloudy skies, northwest winds of 3 to 7 miles per hour and temperatures from 66 to 93 degrees Fahrenheit. The nearest NSA (NSA #1) is a residence located about 3,820 feet south of the center of the proposed LNG liquefaction trains.

Sound level measurements were collected at the nearest NSAs to the Project site identified as follows:

- NSA #1 - West end of Private Drive off Big Lake Road, north of Airhart Road
- NSA #2 - East end of Private Drive off Big Lake Road, north of Airhart Road
- NSA #3 - 8366 Joe Ledoux Road

Figure 9.3-1 illustrates the Project site and NSA locations. Figures 9.3-2 through 9.3-4 show the hourly average L_{eq} sound level at NSA #1, #2, and #3 respectively.

A summary of the existing noise levels is provided in Table 9.3-1.

Table 9.3-1 Existing Noise Level Summary for the Project Site

NSA	Distance from NSA (feet)	Direction from NSA	Average Daytime L_{eq} (dBA)	Average Nighttime L_{eq}(dBA)	Calculated Ldn (dBA)
#1	3,820	North	46.9	43.8	50.8
#2	4,485	Northwest	48.7	44.8	52.0
#3	7,075	Northwest	43.6	40.2	47.3

Figure 9.3-1
Noise Sensitive Area (NSA) Locations Nearest to the Magnolia LNG Project Site

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary

NSA Location

N W E S

MAGNOLIA LNG

0 1,000 2,000 Feet

1:12,000

Source- ESRI 2011-2012
Image Date- 08/27/2013
Date: 4/15/2014

This page left blank intentionally.

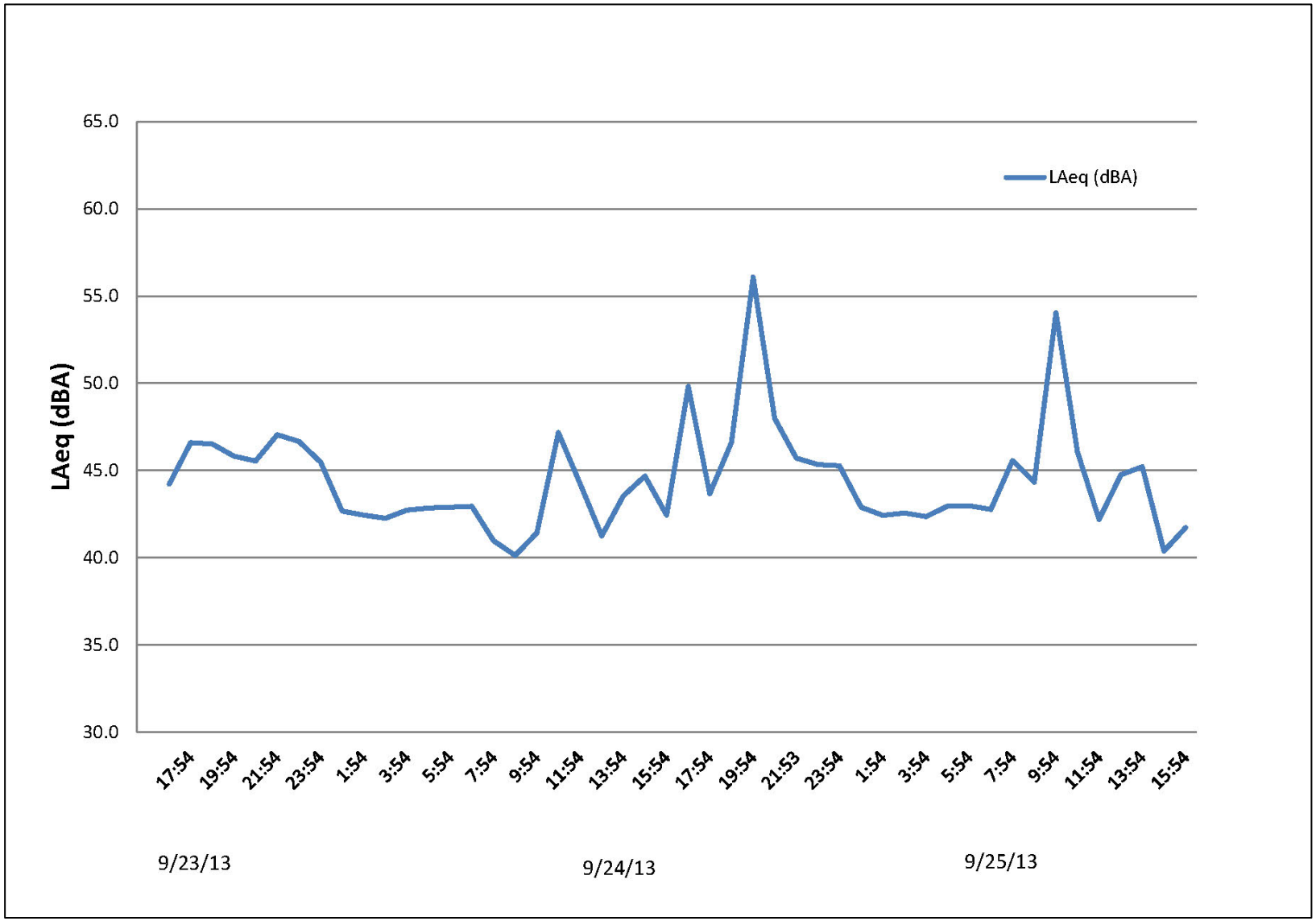


Figure 9.3-2 Hourly LAeq Noise Level (dBA) – Receptor 1

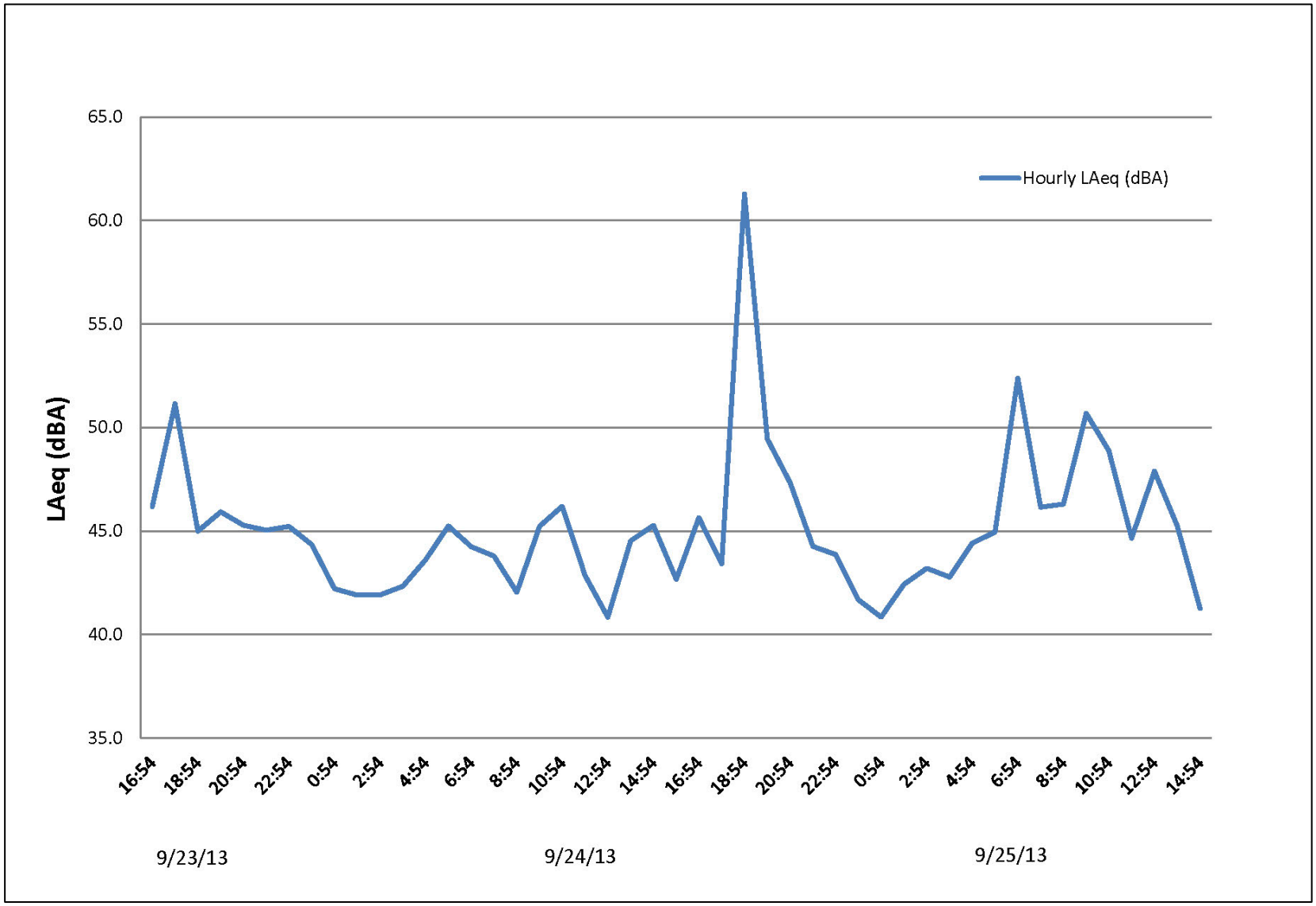


Figure 9.3-3 Hourly LAeq Noise Level (dBA) – Receptor 2

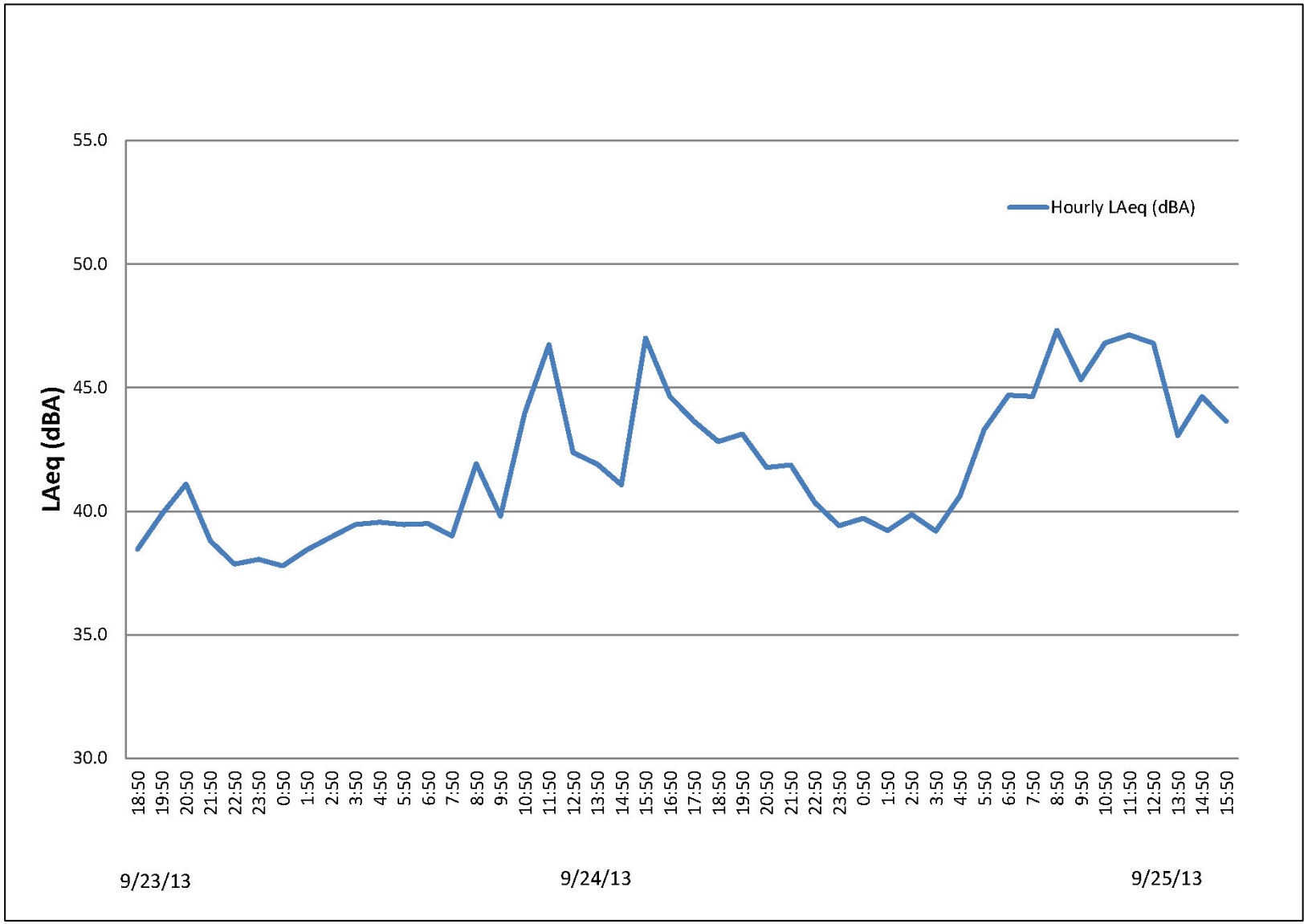


Figure 9.3-4 Hourly LAeq Noise Level (dBA) – Receptor 3

9.3.3 Acoustical Analyses

9.3.3.1 Construction Noise

Construction activities at the Project site would involve clearing and grading, placement of fill, installation of foundations for the planned Project facilities, other equipment settings, ancillary equipment, piping, and structures, pile-driving, and dredging. Construction is projected to begin in mid-2015 (July 1, 2015) with proposed facilities placed into service by June 2018. Construction of the Project would cause temporary increases in ambient noise levels in the immediate vicinity of the construction sites. Construction operating hours would be from 7:00 a.m. to 7:00 p.m., Monday through Saturday.

Noise levels resulting from construction equipment are dependent on several factors including the number and type of equipment operating, the level of operation, and the distance between sources and receptors. The loudest equipment during construction would contribute to a composite average or equivalent site noise level. Heavy construction equipment typically generates noise levels up to approximately 95 dBA at 50 feet. As part of this analysis, acoustic noise modeling was conducted to estimate the construction noise levels at the nearest NSAs around the Project site. Tables 9.3-2 and 9.3-3 present the expected Project construction equipment types and quantities for site preparation and facility construction that were used in the noise calculations and the estimated noise levels at various distances. Noise emission levels were gathered from equipment manufacturers and government agency references. The usage factors were selected from the Federal Highway Administration Highway Construction Noise Handbook (U.S. Department of Transportation 2006). Usage factors are used to account for the intermittent use of construction equipment throughout the course of a normal workday.

Table 9.3-2 Site Preparation Construction Noise Levels at Various Distances

				Distance in Feet/SPL[1] (dBA)				
Construction Equipment	Quantity	Usage Factor %	L_{max} SPL @ 50 Feet (dBA)	50 (adjusted)[2]	250	500	1000	1500
Pickup Truck	3	40	75	76	62	56	50	46
Flatbed Truck	1	40	74	70	56	50	44	40
Dump Truck	8	40	76	81	67	61	55	52
Fuel Truck	1	40	76	72	58	52	46	42
Dozer	6	40	82	86	72	66	60	56
Backhoe	2	40	78	77	63	57	51	47
Trackhoe	3	40	78	79	65	59	53	49
Grader	2	40	85	84	70	64	58	54
Sheepsfoot Roller	4	20	80	79	65	59	53	49
Drum Roller	4	20	80	79	65	59	53	49
			Composite Noise Level	**90**	**76**	**70**	**64**	**61**

[1]SPL = Sound Pressure Level
[2]Adjusted to usage factor and equipment quantity
Source: U.S. Department of Transportation August 2006.

Table 9.3-3 Facility Construction Noise Levels at Various Distances

Construction Equipment	Quantity	Usage Factor %	L_{max} SPL @ 50 Feet (dBA)	Distance in Feet/SPL[1] (dBA)				
				50 (adjusted)[2]	250	500	1000	1500
Pickup Truck	2	40	75	74	60	54	48	44
Flatbed Truck	2	40	74	73	59	53	47	43
Cement Truck	2	40	79	78	64	58	52	48
Cement Pump Truck	2	20	81	77	63	57	51	47
Fork Truck	2	40	84	83	69	63	57	53
Manlift	2	20	75	71	57	51	45	41
Backhoe	2	40	78	77	63	57	51	47
Trackhoe	2	40	78	77	63	57	51	47
Picker	6	16	81	81	67	61	55	51
Welder	4	40	74	76	62	56	50	46
Compressor	2	40	78	77	63	57	51	47
Compactor	2	20	83	79	65	59	53	49
			Composite Noise Level	**89**	**75**	**69**	**63**	**59**

[1]SPL = Sound Pressure Level
[2]Adjusted to usage factor and equipment quantity
Source: U.S. Department of Transportation August 2006.

Since the nearest noise-sensitive receptor property to the Project is approximately 3,820 feet from the approximate center of the construction site, the estimated noise level due to Project construction at that distance would be 52 dBA during site preparation and 51 dBA during facility construction. These levels might occur temporarily over the course of the Project construction and would be audible at times at the nearest NSAs.

Pile Driving

The steel sheet bulkhead for the LNG loading platform would be installed by use of vibratory hammer or a hydraulic pile driver. The five monopile steel breasting dolphin foundations also would be installed using a hydraulic pile driver. Likewise, the 24 cylindrical concrete pilings driven into the seabed to support the LNG loading platform would be installed using a hydraulic pile driver. The proposed foundation arrangement for each LNG storage tank would include the use of 1,508 pre-stressed concrete piles of 2 feet by 2 feet in cross-section by 70 feet in length. The two LNG storage tanks would have a combined total of 3,016 piles. The piles would be driven by hydraulic hammer as is typical of these installations. The installation would occur over a multiple month period (refer to RR1, "General Project Description," Appendix 1.C) due to the number of pilings required (refer to RR 13, "Engineering and Design Material") for the proposed arrangement and piling specifications and numbers). Figure 9.3-5 shows the approximate location of the pile-driving activities in relation to the nearest NSAs.

The expected L_{max} sound level for a pile driver operation is 101 dBA. The sound level due to the pile driver operation at the NSAs can be calculated based on the formula for geometric spreading of sound energy over distance. Assuming three simultaneous pile-driving operations at the approximate center of the Project construction area, the predicted sound level due to pile-driving would be about L_{max} 68 dBA at the nearest NSA (see Table 9.3-4). Three pile-drivers would likely be in operation most of the time; however, a fourth pile-driver may be brought on-site depending on possible schedule delays and weather. With four simultaneous pile-driving operations at the approximate center of the Project construction area, the predicted sound level due to pile-driving would be about L_{max} 69 dBA at the nearest NSA.

This is a conservative estimate in that no reductions were taken for the effect of ground or atmospheric absorption. The pile-driving operation would be audible at the nearest NSAs but would be temporary in duration.

Table 9.3-4 Pile-Driving SPLs at NSAs

Number of Simultaneous Pile Driving Operations	NSA	Distance from NSA to Approximate Center of Construction Area (feet)	Direction from NSA	SPL Three Hydraulic Pile Drivers (L_{max}) at 50 feet	L_{max} SPL at NSAs (dBA)
3	#1	3,820	North	106	68
3	#2	4,485	Northwest	106	67
3	#3	7,075	Northwest	106	63
4	#1	3,820	North	107	69
4	#2	4,485	Northwest	107	68
4	#3	7,075	Northwest	107	64

Table 9.3-5 presents the estimated duration for the pile-driving activities based on three pile-driving rigs in some cases operating simultaneously and each rig being able to drive 17 piles per day.

Table 9.3-5 Pile-Driving Duration

Pile-Driving Activity	Duration (months)
Sheet steel bulkhead	3.5
Monopile steel breasting dolphin foundations	2
Cylindrical concrete pilings	3.5
LNG storage tanks (2)	3

Document Path: C:\VPN_WORK\active_projects\Magnolia_LNG_2014\maps\mxds\rr9\Approximate Location of Pile Driving Activates to Noise Sensitive Area Locations.mxd

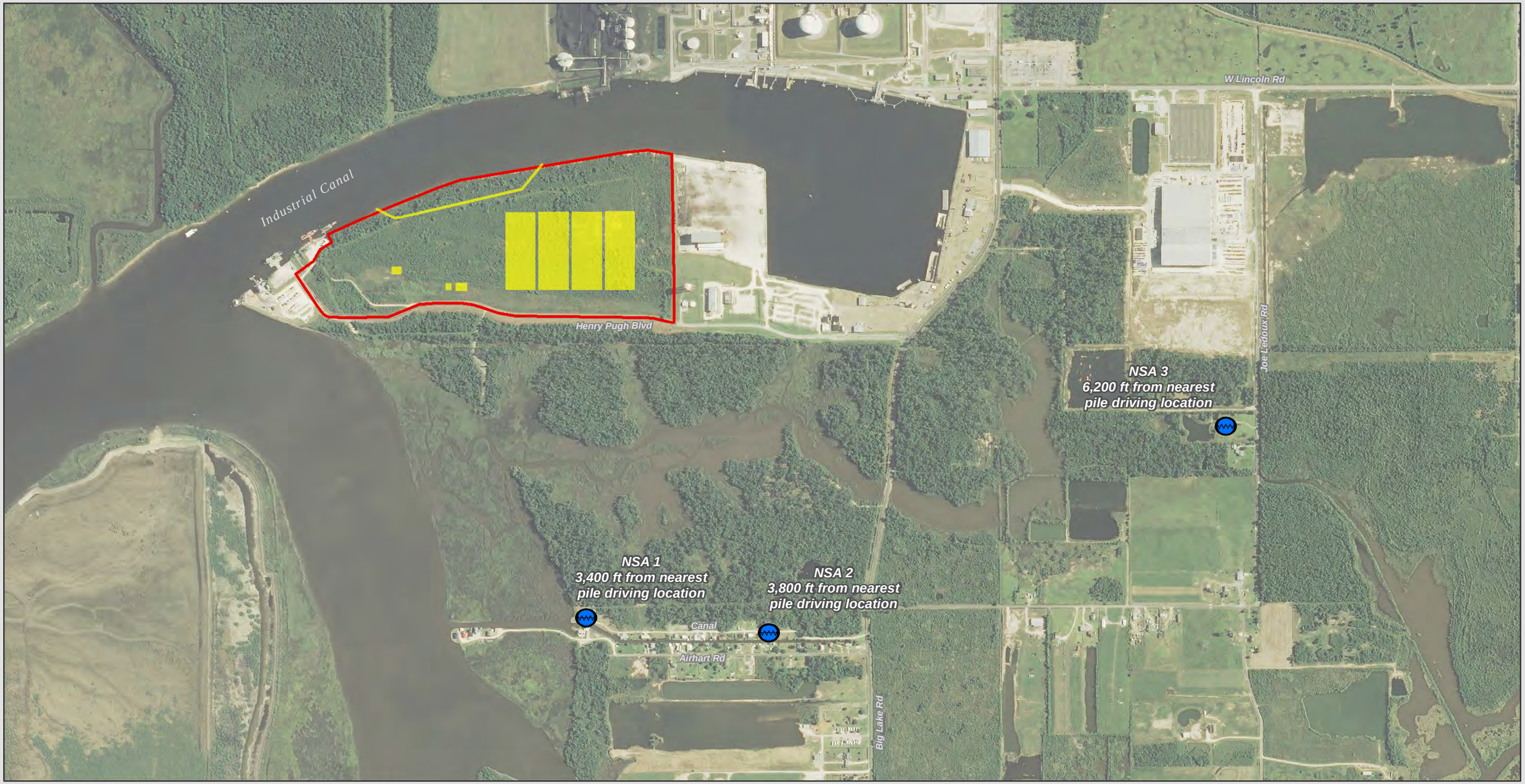


Figure 9.3-5
Approximate Location of Pile-Driving Activities in Relation to Noise Sensitive Area (NSA) Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

- Proposed LNG Facility Boundary
- NSA Location
- Pile-Driving Activity Area

N W E S

MAGNOLIA LNG

0 1,000 2,000 Feet

1:12,000

Source- ESRI 2012, NAIP 2013
Image Date- 08/27/2013
Date: 4/28/2014

This page left blank intentionally.

Dredging

The LNG vessel loading facility would be recessed into the northern boundary of the site. To create the recessed berthing and waterway access area, a combination of onshore excavation and dredging would be required at the site (see Figure 9.3-6 for dredging location). Dredging would be accomplished by use of a hydraulic cutterhead suction dredge. Generally, hydraulic dredges generate noise at around 60 to 80 dBA at 50 feet, depending on size of dredge, engine, and other characteristics. Table 9.3-6 presents the noise levels at the nearby NSAs based on an upper dredging noise level of 80 dBA at 50 feet.

Table 9.3-6 Dredging SPLs at NSAs

NSA	Distance from NSA (feet)	Direction from NSA	Hydraulic Dredge (L_{eq}) at 50 feet	SPL at NSAs (dBA)
#1	4,400	North	80	41
#2	5,100	Northwest	80	40
#3	7,300	Northwest	80	37

Vibration

Operation of construction equipment causes ground vibrations that spread through the ground and diminish in strength with distance. According to the Federal Transit Administration (FTA), pile-driving would be the greatest source of vibration during the Project construction. The vibration level at a receptor location can be calculated based on the distance from the site using the following equation:

$$L_v(D) = L_v(25\ ft) - 20\log(D/25)$$

Where:

D = distance (feet)

L_v = vibration level (VdB)

Using this equation with a level of 112 VdB for a single pile-driver at 25 feet (FTA 2006), the vibration level at the nearest NSA (NSA #1) would be 68 VdB. This level is below the FTA impact criteria for general assessment for ground-borne vibration of 72 VdB for a residence. Although three and possibly 4 pile drivers could be operating simultaneously, it would be unlikely that the vibrational waves generated by the pile drivers would coincide due to different equipment locations and likely non-coincident driver strike times.

9.3.3.2 Operational Noise

Operation of the proposed Project may result in long-term increases in noise levels in the vicinity of the Project. Noise would generally be produced on a continuous basis by the Project equipment including compressors, power generation units, pumps, and cooling fans.

To identify potential noise impacts resulting from the operation of the Project, acoustic modeling was conducted and the modeling results were compared with the FERC limit of Ldn 55 dBA. Acoustic noise modeling of the major Project sources was conducted using the CadnaA acoustic model version 3.7.124 developed by Datakustik GmbH.

Primary noise-producing equipment to be included in the Project, along with corresponding estimated noise emission data and noise control equipment reduction values were derived from equipment manufacturer's data sheets and measurements at other LNG facilities. The model simulates the outdoor three-dimensional propagation of sound from each noise source and accounts for sound wave divergence, atmospheric and ground sound absorption, and sound attenuation due to interceding barriers and topography based on the International Standard ISO9613-2 (ISO 1996). Standard conditions of 50 degrees Fahrenheit and 70 percent relative humidity were assumed. Ground absorption was set to 1. A database was developed that specified the location and sound power levels of each noise source. A receptor grid was specified that covered the entire area of interest. The model calculated the overall A-weighted sound pressure levels (SPLs) within the receptor grid based on the sound level contribution of each noise source. The model receptors included the three identified NSAs.

Table 9.3-7 presents the unmitigated sound levels for the major noise-producing equipment associated with the Project. Figure 9.3-7 illustrates the locations of the major noise-producing equipment. This figure shows one of the four LNG trains; locations in the other trains would be similar. Table 9.3-8 presents the noise reduction values for the potential noise controls that were included in the model.

The results of the noise modeling for the Project operation with the noise control measures from Table 9.3-8 included are presented in Table 9.3-9. The results indicate that sound levels associated with the operation of the Project at the nearest NSA would be 52.1 dBA Ldn, which is below the FERC limit of Ldn 55 dBA. Table 9.3-9 also presents the expected increase in Ldn above the existing Ldn. The expected increases in noise levels at the NSAs are shown to be small, ranging from 0 dBA to 1.3 dBA. Increases this small are not considered to be perceptible.

Flaring events would occur infrequently, mainly during startup or shutdown of the proposed Magnolia LNG facility. Typically gas is flared for one to two hours during these events. This may occur at frequencies of the order of three to four times a year. The flaring creates noise with a low-pitched 'roaring' character. The peak sound pressure level for a high pressure flare at 1,500 feet is 80 dBA (Baukal 2001). The estimated SPL at NSA # 1 (the nearest NSA at a distance of 3,820 feet from the Project site) during a flaring event would be 72 dBA.

Document Path: C:\VPN_WORK\active_projects\Magnolia_LNG_2014\maps\mxds\rr9\Approximate Dredging Location in Relation to Noise Sensitive Area Locations rr9.mxd

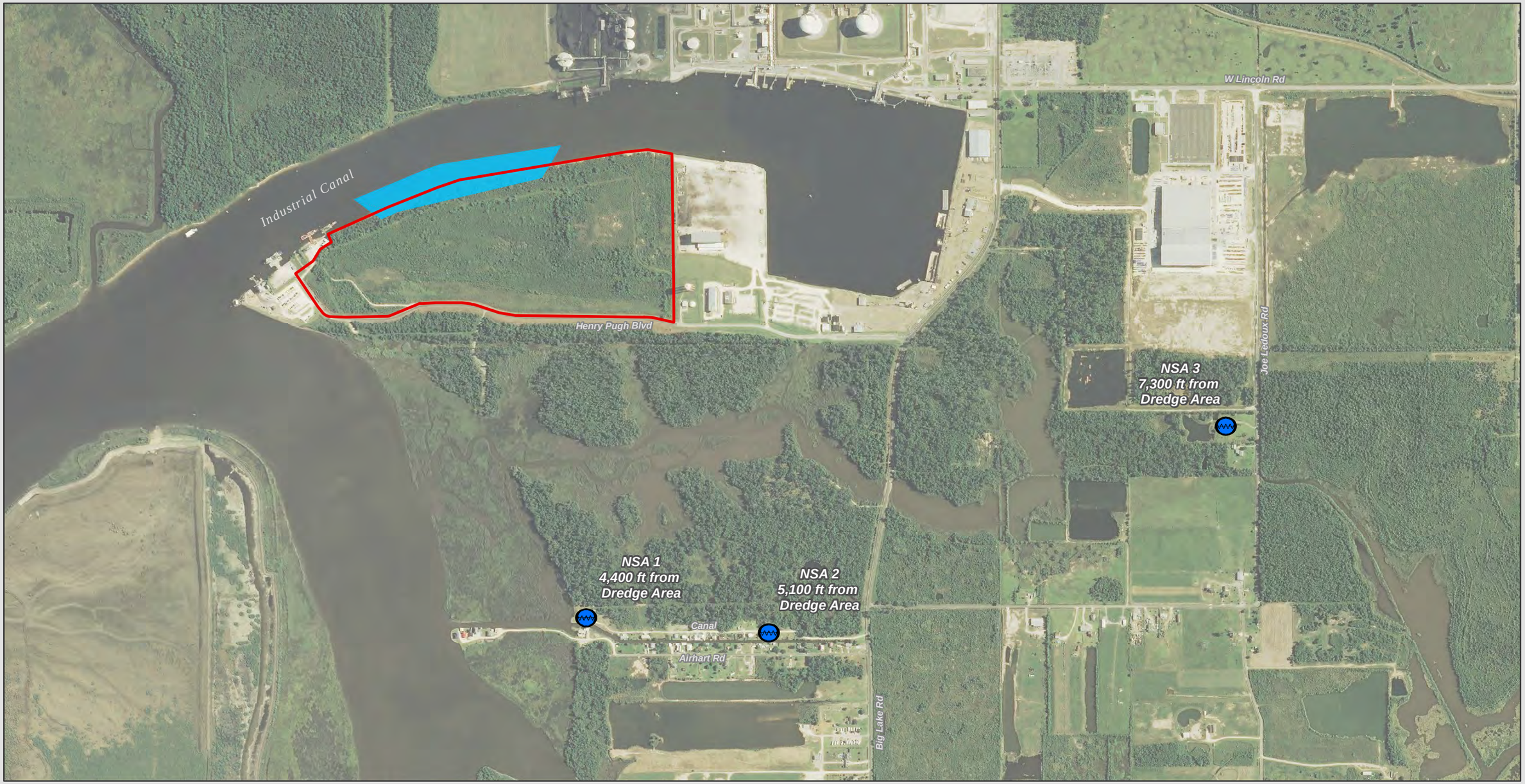


Figure 9.3-6
Approximate Dredging Location in Relation to Noise Sensitive Area (NSA) Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary
NSA Location
Dredge Area

N W E S

MAGNOLIA LNG

0 1,000 2,000 Feet

1:12,000

Source- ESRI 2012, NAIP 2013
Image Date- 08/27/2013
Date: 4/28/2014

This page left blank intentionally.

Table 9.3-7 Unmitigated Sound Levels for Major Noise-Producing Equipment

Equipment	Quantitiy Modeled	Weight	Sound Power/Octave Spectrum Band (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	dBA
LM2500+Gas Turbine Compressor/Generator Package	8	Lw	77	86	99	97	96	95	99	100	96	105.1
LM2500+Gas Turbine Compressor Exhaust	8	Lw	91	107	119	126	130	129	128	129	120	135.1
Solution Cooler Fan Unit	128	LwA		81	91	95	98	97	95	92	82	103.2
Cooler Fan	40	Lw	69	79	85	89	89	89	88	87	79	94.5
Steam Generator	8	Lw		77	88	92	97	100	99	98	92	105.1
Amine Charge Pumps	8	LwA		67	78	87	93	99	97	93	85	102.5
Miscellaneous Pumps	54	Lw	91	93	95	95	95	95	95	92	85	100.6
Instrument Air Package	12	Lw	91	96	93	98	95	91	88	90	89	98.1
Boil-off Gas Compressor	5	Lw	113	114	118	116	105	106	101	99	94	111.9
Boil-off Gas Compressor Motor	5	Lw	95	95	98	100	103	103	102	97	89	107.7
Ammonia Compressor	8	LwA	-	-	-	-	-	-	-	-	-	85
Liquefaction Train Piping	4	Lw	16	29	39	83	112	115	103	92	73	116.2

Table 9.3-8 Noise Control Reduction Values

Noise Source	Noise Control	Noise Reduction/Octave Spectrum Band (Hz) 31.5	63	125	250	500	1000	2000	4000	8000
Gas Turbine Exhaust	Gas Turbine Exhaust Silencer	2	5	12	24	34	40	39	31	11
BOG Compressors	BOG Building Enclosure	8	12	11	16	26	34	41	44	46
Liquefaction Train Pipe	Pipe Lagging	0	0	0	2	11	20	29	36	42

Table 9.3-9 Summary of Project Operation Noise Levels at NSAs and Expected Increase in Ldn Above the Existing Ldn

NSA	Distance from NSA (feet)	Direction from NSA	Existing Ambient Ldn (dBA)	Project Contribution Ldn (dBA)	Combined Ldn (dBA)	Expected Increase
#1	3,820	North	50.8	46.4	52.1	1.3
#2	4,485	Northwest	52.0	44.5	52.7	0.7
#3	7,075	Northwest	47.3	24.4	47.3	0.0

This page left blank intentionally.

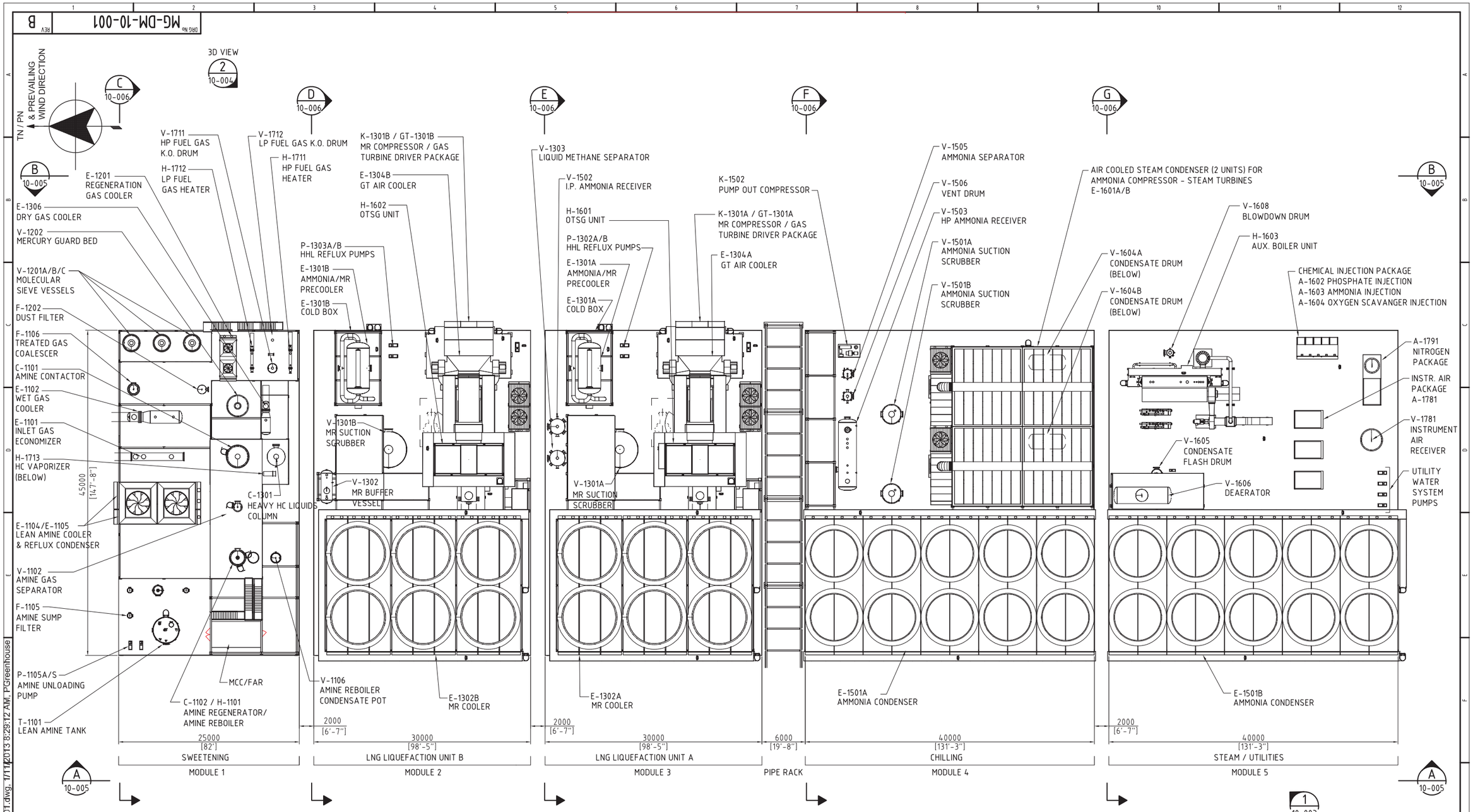


Figure 9.3-7 Locations of Major Noise-Producing Equipment (1 of 4 Trains)

PLAN

NOTE:

1. EQUIPMENT LAYOUT AND SIZING IS BASED ON PRELIMINARY VENDOR INFORMATION.
2. DIMENSIONS SHOWN ARE APPROXIMATE AND ONLY FOR INDICATIVE REFERENCE.

TRAIN 1

NOTE : THIS DRAWING REPRESENTS TRAIN 1 ONLY

INFORMATION ONLY NOT TO BE USED FOR CONSTRUCTION

DRAWING No	REFERENCE DRAWINGS	REV	DATE	REVISION DESCRIPTION	DRAWN	CHECKED	DESIGNED	APPROVED
		B	7 NOV'13	UPDATE	PNG	LC	LC	PB
		A	08 OCT'13	ISSUED FOR INFORMATION	PNG			

MAGNOLIA LNG

DRAWN:	PNG	DATE:	08 OCT'13
CHECKED:	LC	DATE:	7 NOV'13
ENGINEER:	LC	DATE:	7 NOV'13
APPROVED:	PB	DATE:	7 NOV'13
CLIENT:		DATE:	

MAGNOLIA LNG PROJECT
LIQUEFACTION TRAIN No 1
EQUIPMENT / MODULE ARRANGEMENT
PLAN

SCALE: AS SHOWN | DRG No MG-DM-10-001 | REV B

K:\Projects\Magnolia_LNG\CAD\ME\DRG\MG-DM-10-001.dwg, 1/11/2013 8:29:12 AM, PGreenhouse

This page left blank intentionally.

9.3.4 Mitigation

9.3.4.1 Project Construction

The following mitigation measures may be implemented as needed to control construction noise:

- Locate stationary construction equipment away from noise receptors where feasible.
- Turn off idling equipment when not in use.
- Install temporary acoustic barriers around stationary construction noise sources, as feasible.
- Perform construction during daytime hours when there is less sensitivity to sound.
- Ensure that all equipment has sound control devices no less effective than those provided by the manufacturer.

9.3.4.2 Project Operation

Mitigation measures included in the acoustic model for the operation of the Project are gas turbine exhaust silencers, the boil-off gas compressor building enclosure, and pipe lagging on the liquefaction train piping (see Table 9.3-8).

9.4 CUMULATIVE IMPACTS

As discussed in RR 1, "General Project Description" (see Section 1.9, "Cumulative Impact Analysis,"), cumulative impacts are the collective result of the incremental impacts of an action that, when added to the impacts of other past, present, and reasonably foreseeable future actions, would affect the same resources, regardless of what agency or person undertakes those actions (40 CFR 1508.7). Procedures for developing the cumulative project inventory are discussed in RR 1, Section 1.9.

9.4.1 Air Quality

For air quality, a subset of the potential cumulative projects identified in RR 1, Table 1.9-1 would have the potential to produce a cumulative air pollutant impact with the proposed Project. The potential for cumulative impacts is based on the type of project, its stage of development and the likely potential for significant ongoing air pollutant emissions whose impact may overlap with the Project. Planned projects (i.e., projects that have documented and submitted their emissions for public review) up to 10 miles away from the Project would have the potential for a cumulative impact on air quality; facilities beyond 10 miles may have a potential for additional cumulative impacts depending on their potential emissions. Projects within 10 miles of the proposed Project site include:

- Trunkline LNG
- G2X Energy
- W.R. Grace
- Cameron LNG
- Lake Charles Cogeneration
- Westlake Chemical
- Sasol North America

Cumulative impacts will be assessed with dispersion modeling through the air permitting process. Modeling will be required to address Project-only impacts in comparison to the SILs contained in NSR PSD impact assessment requirements. Modeled air pollutant concentrations above the respective SILs outside of the Project site's fence line would indicate a potential for cumulative impact with other facilities. Based on the distance beyond the fence line where Project-only modeled concentrations decrease below the SIL, a radius of influence is established. A cumulative source emission inventory will then be developed for major emission sources within the radius of influence and included in a cumulative modeling assessment.

Cumulative impacts on regional ozone levels would also be addressed through a photochemical modeling study, if required by the LDEQ.

If modeling for permit application support does not indicate modeled concentrations beyond the fence line are above respective SILs, Magnolia will perform a cumulative modeling assessment focused on nearby facilities to address the FERC's concern regarding cumulative impacts.

Generally, construction projects with multiple-year overlapping construction schedules or single-year projects that occur in the same year could contribute to a cumulative impact. Construction emissions typically consist of equipment and vehicle exhaust emissions and fugitive dust. Construction cumulative impacts are highly variable and difficult to predict due to several factors that vary spatially and temporally for the group of projects contributing to a potential cumulative effect. These factors include timing of the construction projects, intensity and type of construction activity underway at any given time, quantity and size of emission producing equipment in operation, distance separating the projects and factors that affect fugitive dust emissions such as soil silt content, quantity of dust-producing material being handled, and dry or windy conditions. When construction is complete for a project, it would no longer contribute to construction cumulative effects with other projects.

Potential projects in proximity to the Project include three proposed projects within 0.5 mile of the Project site. These projects are G2X Energy, Trunkline LNG, and the Lake Charles Fisheries Research Center. Two of these projects, G2X Energy and Trunkline LNG, anticipate a construction period beginning in 2014 and ending in 2017 (see Table 1.9-1 in RR 1, "General Project Description"). This construction period would overlap with the Project's construction period of mid 2015 through 2017. The construction of the Lake Charles Fisheries Research Center would not overlap with the construction of the Magnolia Project, and the construction

schedule will not be established until after the facility is designed; therefore, it is not possible to speculate on its potential to contribute to a cumulative impact.

Cumulative impacts due to the combination of construction emissions from the Project with G2X Energy and Trunkline LNG are possible. Preliminary construction activity information and construction emission estimates are available for Trunkline LNG from their FERC RR 9, but are not available for G2X Energy (G2X is not subject to FERC jurisdiction or any other requirement to estimate construction emissions). The potential cumulative impact with the Project's construction emissions shown in Table 9.2-4 would, therefore, be limited. The potential for cumulative construction emissions impacts would be greatest during site preparation when fugitive dust production would likely be at its peak due to excavation, grading, transport of soil and gravel and similar types of basic site preparation activities. If G2X Energy and Trunkline LNG begin construction in 2014 as shown in Table 1.9-1 of RR 1, the first phase of both projects would likely be site clearing and preparation activity in 2014. Assuming that these two projects have a site preparation phase similar in duration to the Project's, their peak fugitive dust production period would be completed prior to the start of the Project's site preparation phase in the latter half of 2015, minimizing the potential for a fugitive dust cumulative impact. Mitigation measures are also available to minimize fugitive dust such as applying water or other dust control chemicals to control dust, or limiting activity during windy conditions. Mitigation would need to be coordinated amongst all potential contributors to a fugitive dust cumulative impact.

Emission of criteria pollutants from combustion of fuel in equipment and vehicle exhaust could also contribute to a cumulative impact. These emissions would be minimized by typical control techniques such as use of low-sulfur diesel fuel, proper operation of equipment and reduction of daily emissions by using equipment during daylight hours only as much as possible.

9.4.2 Climate Change

National and international organizations have identified that GHGs have been increasing in concentration in the atmosphere since the late 1700s and identify them as the primary factor affecting climate change. The primary source of these gases is combustion of fossil fuels, with coal combustion emitting the highest amount of GHG per energy unit. Deforestation and agriculture also contribute to the rise in GHG concentration in the atmosphere. Climate change is inherently a cumulative issue since impacts such as sea level rise and increasing average air temperatures are believed to be the result of cumulative emissions from worldwide sources. However, at the project level, there is no available method to assess a project's individual GHG emission impact on changes in climate.

GHG emissions from the construction and operation of the proposed Project are discussed in Sections 9.2.5 and 9.2.6, respectively. Magnolia is incorporating highly efficient processes to minimize to the extent feasible emissions of GHGs. For circulating the MR, the Project would use aeroderivative gas turbines rather than larger, less-efficient frame gas turbines. CHP technology would be employed to recover waste heat from each gas turbine exhaust in order to generate high pressure (HP) steam, which is then used to drive the auxiliary ammonia-based cooling system and other various processes at the facility, thereby reducing the need for

supplemental fossil fuel based energy. In addition, the auxiliary ammonia-based cooling system would serve to increase the output of the gas turbines and also the fuel efficiency of the gas turbines by chilling the inlet air to maintain a stable inlet air temperature, allowing the gas turbine combustion process to be optimized for efficiency. The ammonia cooling system would also be used to pre-cool the feed gas and the MR prior to entering the cold box. This would increase efficiency of the cold box by lessening the temperature difference between the two gas streams. Therefore, as the MR exits the cold box, it would return to the main MR compressor at a lower temperature due to the pre-cooling, significantly improving MR compressor performance, reducing energy demand and emissions. As noted in Section 9.1, "Project Description," these features would increase the efficiency of the Project by approximately 30 percent compared to conventional liquefaction processes, and thus would minimize GHG emissions.

9.4.3 Noise

Noise decreases logarithmically with increasing distance from a noise source, therefore cumulative operational noise impacts would only occur with other facilities in immediate proximity to the Project. Two facilities, Trunkline LNG and G2X Energy, are approximately 0.5 mile from the Project site and could potentially create a cumulative noise impact. However, as shown in Table 9.3-9, noise impacts due to the Project at noise sensitive locations 3,280 feet from the Project site and beyond would be less than the FERC 55dBA threshold. Considering that the FERC 55dBA noise thresholds will also apply to the Trunkline LNG facility, cumulative noise impacts are expected to remain below 55dBA for cumulative impacts from these two facilities. The G2X Energy facility is not regulated by FERC and thus not subject to the FERC noise threshold; however, the G2X facility is located 0.5 mile north of the Project and would not be expected to contribute significantly to the noise levels at the Project NSAs. The G2X facility would be subject to Calcasieu Parish noise regulations found in the Calcasieu Parish Police Jury Code of Ordinances, Chapter 18, Article VIII.

Cumulative construction noise impacts depend on the overall timing of construction for each project and the type of daily construction activities occurring at each facility. Magnolia will minimize its construction noise using mitigation described in Section 9.3.4.1, "Project Construction," to limit cumulative construction noise impacts to the extent feasible for its own construction procedures.

9.5 REFERENCES

Baukal, Jr., C. E. (ed.). 2001. *The John Zink Combustion Handbook*. CRC Press, LLC, Boca Raton, Florida.

Federal Transit Administration (FTA). 2006. Transit Noise and Vibration Impact Assessment. FTA-VA-90-1003-06. May 2006. U.S. Department of Transportation, Office of Planning and Environment, Federal Transit Administration, Washington, D.C.

ICF International. 2009. Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories. Final Report, April 2009. Prepared for U.S. Environmental Protection Agency. ICF International, Fairfax, Virginia.

International Standards Organization (ISO). 1996. ISO 9613-2, *Acoustics-Attenuation of Sound During Propagation Outdoors-Part 2*. December 15, 1996.

National Oceanic and Atmospheric Administration (NOAA). 2012. *Local Climatological Data Annual Summary for 2012 with Comparative Data,* Lake Charles Louisiana. National Climatic Data Center, Asheville NC.

U.S. Environmental Protection Agency (USEPA). 2005. Maintenance Plan Guidance Document for Certain 8-Hour Ozone Areas Under Section 110(a)(1) of the Clean Air Act. Memorandum from Lydia Wegman, Director Air Quality Strategies and Standards Division to Air Division Directors, Regions I-X. May 20, 2005.

———. 2008. NONROAD Model (nonroad engines, equipment, and vehicles). http://www.epa.gov/otaq/nonrdmdl.htm. Accessed November 2013.

———. 2012. AirData, online air monitor database. http://www.epa.gov/airdata. Accessed November 2013.

U.S. Department of Transportation. 2006. FHWA Highway Construction Noise Handbook. August 2006.

This page left blank intentionally.

APPENDICES

9.A: Construction Emissions

9.B: Operational Emissions

- 9.B.1 Operational Emissions Calculations
- 9.B.2 Fugitive Emissions Calculations *[PRIVILEGED]*

9.C: Air Modeling Protocols and Associated Correspondence

- 9.C.1 Air Quality Modeling Protocol
- 9.C.2 Marine and Stationary Sources Air Quality Modeling Protocol
- 9.C.3 Modeling Protocol - Ozone Impact Analysis of the Proposed Magnolia LNG Project

9.D: Noise Study

9.E: Air Permit Application *[Pending LDEQ Review]*

This page left blank intentionally.

Appendix 9.A
Construction Emissions

This page left blank intentionally.

Appendix 9.A - Table of Contents

Table 9.A.1 - Construction Emission Summary
Table 9.A.2 - Phase I Site Preparation Construction Emissions - Year 2015
Table 9.A.3 - Phase II LNG Tank Construction Emissions - Year 2015
Table 9.A.4 - Phase II LNG Tank Construction Emissions - Year 2016
Table 9.A.5 - Phase II LNG Tank Construction Emissions - Year 2017
Table 9.A.6 - Phase III LNG Tank Construction Emissions - Year 2015
Table 9.A.7 - Phase III LNG Tank Construction Emissions - Year 2016
Table 9.A.8 - Phase III LNG Tank Construction Emissions - Year 2017
Table 9.A.9 - Phase IV Architectural - Year 2016
Table 9.A.10 - Phase IV Architectural - Year 2017
Table 9.A.11 - Phase V Marine Work - Year 2015
Table 9.A.12 Phase V Marine Work - Year 2016
Table 9.A.13 Phase V Marine Work - Year 2017
Table 9.A.14 Phase VI Miscellaneous - Year 2015
Table 9.A.15 Phase VI Miscellaneous - Year 2016
Table 9.A.16 Phase VI Miscellaneous - Year 2017
Table 9.A.17 - Construction Material Transport by Tug/Barge in Year 2016
Table 9.A.18 - Tug/Barge Construction Material Transport Activity List
Table 9.A.19 - Tug and Dredge Vessel Emission Factors
Table 9.A.20 - Fugitive Dust Emissions from General Site Work and Earth Moving
Table 9.A.21 - Fugitive Dust Emissions from Unpaved Roads
Table 9.A.22 - On-Road Worker Commute Emissions

This page left blank intentionally.

Table 9.A.1 - Construction Emission Summary

2015 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.64	0.73	0.71	3.11	6.43	1817	0.33
Phase II LNG Tanks	1.04	1.01	0.98	13.45	10.07	2599	0.47
Phase III BOP	0.54	0.55	0.53	5.16	5.29	1435	0.26
Phase IV Architectural	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase V Marine	0.38	0.40	0.40	2.97	11.52	954	1.08
Phase VI Misc	0.09	0.09	0.09	2.40	0.56	225	0.04
Fugitive Dust	n/a	14.87	1.49	n/a	n/a	n/a	n/a
Worker Commuting	0.02	0.02	0.01	1.63	0.12	238	0.01
Total	2.72	17.66	4.20	28.73	33.99	7,269	2.18

2016 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase II LNG Tanks	4.08	2.94	2.85	92.92	24.49	8739	1.52
Phase III BOP	0.43	0.35	0.34	5.78	2.89	1010	0.17
Phase IV Architectural	1.39	0.25	0.24	49.19	3.66	856	0.15
Phase V Marine	1.21	0.85	0.83	30.93	12.04	2523	1.04
Phase VI Misc	0.12	0.14	0.13	0.48	0.83	427	0.07
Fugitive Dust	n/a	14.35	1.43	n/a	n/a	n/a	n/a
Tug Transport	0.54	0.60	0.60	4.96	25.80	1385	2.58
Worker Commuting	0.04	0.03	0.01	2.80	0.21	408	0.01
Total	7.80	19.50	6.43	187.06	69.93	15,349	5.54

2017 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase II LNG Tanks	2.85	1.51	1.47	88.41	11.73	4022	0.70
Phase III BOP	0.21	0.13	0.13	4.63	0.85	372	0.06
Phase IV Architectural	1.18	0.16	0.15	45.74	2.59	654	0.12
Phase V Marine	0.40	0.25	0.24	11.58	1.66	858	0.14
Phase VI Misc	0.11	0.12	0.12	0.40	0.62	396	0.06
Fugitive Dust	n/a	14.26	1.43	n/a	n/a	n/a	n/a
Worker Commuting	0.04	0.03	0.01	2.80	0.21	408	0.01
Total	4.79	16.45	3.54	153.56	17.67	6,711	1.09
Summary - all years	**15.31**	**53.61**	**14.17**	**369.35**	**121.59**	**29,329**	**8.82**

This page left blank intentionally.

Table 9.A.2 - Phase I Site Preparation Construction Emissions - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

Site Preparation: Earth Moving/Road Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15	21.36	21.66	21.01	39.51	163.59	77312	12.52
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5	21.36	21.66	21.01	39.51	163.59	77312	12.52
DUMP TRUCK 6CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	38.53	45.09	43.74	157.72	403.14	132878	23.48
DUMP TRUCK 14CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	38.53	45.09	43.74	157.72	403.14	132878	23.48
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5	38.53	45.09	43.74	157.72	403.14	132878	23.48
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5	21.36	21.66	21.01	39.51	163.59	77312	12.52
B - EARTH MOVING																		
450 CASE DOZER	100%	6510	Case 650L	74	Diesel	6	6	6	6	6	30	7.78	9.52	9.24	71.49	114.79	20370	3.95
580 BACKHOE	100%	2170	Case 580N	78	Diesel	2	2	2	2	2	10	17.81	16.23	15.74	104.35	85.04	12687	2.55
225 TRACK HOE	100%	3255	Case CX210C	160	Diesel	3	3	3	3	3	15	17.72	13.94	13.52	65.90	110.85	15827	3.18
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	217	Case 885B	214	Diesel	2	2	2	2	2	10	24.38	26.28	25.49	84.59	248.66	73154	13.19
SHEEPSFOOT	50%	2170	Caterpillar CP54B	131	Diesel	4	4	4	4	4	20	17.23	21.63	20.98	74.95	185.35	41820	8.01
DRUM ROLLER	50%	2170	Caterpiller CS44	100	Diesel	4	4	4	4	4	20	13.31	20.02	19.42	129.62	141.05	29773	5.70

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission (ton)						
						6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15	0.01	0.01	0.01	0.01	0.06	28	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5	0.01	0.01	0.01	0.02	0.10	46	0.01
DUMP TRUCK 6CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	0.18	0.22	0.21	0.75	1.93	636	0.11
DUMP TRUCK 14CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	0.18	0.22	0.21	0.75	1.93	636	0.11
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5	0.01	0.02	0.02	0.06	0.14	48	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5	0.00	0.00	0.00	0.00	0.00	2	0.00
B - EARTH MOVING																		
450 CASE DOZER	100%	6510	Case 650L	74	Diesel	6	6	6	6	6	30	0.06	0.07	0.07	0.51	0.82	146	0.03
580 BACKHOE	100%	2170	Case 580N	78	Diesel	2	2	2	2	2	10	0.04	0.04	0.04	0.25	0.20	30	0.01
225 TRACK HOE	100%	3255	Case CX210C	160	Diesel	3	3	3	3	3	15	0.06	0.05	0.05	0.24	0.40	57	0.01
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	217	Case 885B	214	Diesel	2	2	2	2	2	10	0.01	0.01	0.01	0.02	0.06	17	0.00
SHEEPSFOOT	50%	2170	Caterpillar CP54B	131	Diesel	4	4	4	4	4	20	0.04	0.05	0.05	0.18	0.44	100	0.02
DRUM ROLLER	50%	2170	Caterpiller CS44	100	Diesel	4	4	4	4	4	20	0.03	0.05	0.05	0.31	0.34	71	0.01
											Total	***0.64***	***0.73***	***0.71***	***3.11***	***6.43***	***1817***	***0.33***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

This page left blank intentionally.

Table 9.A.3 - Phase II LNG Tank Construction Emissions - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK older then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	1085	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	10.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel					2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT TRUCK	1%	4366.04	Mack Truck Granite Series	415	Diesel				1762	250	2012.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT PUMP TRUCK	100%	4340	Putzmeister 70Z-Meter	450	Diesel				10	10	20.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used					0.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
BUS	1%	10.85	Blue Bird Vision	260	Diesel	1	1	1	1	1	5.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
FORKLIFT	100%	1085	Cat PD10000	77	Diesel	1	1	1	1	1	5.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	20.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
40' MANLIFT	100%	868	JLG 400S Telescopic Boom Lift	49	Diesel					4	4.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used					0.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
100' MANLIFT	100%	0	JLG 1250AJP Articulating Boom Lift	87	Diesel	Not Used					0.0	20.70	15.91	15.43	104.59	94.77	12,194	2.47
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel					2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
TRACTOR/40' FLOAT	20%	434	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	10.0	25.74	18.79	18.23	88.89	172.15	26,237	5.18
UTILITY CARTS (SITE TRANSP)	10%	325.5	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	15.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86
B - EARTH MOVING																		
FARM TRACTOR	100%	434	Kubota L4240	44	Diesel				2		2.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
450 CASE DOZER	20%	86.8	Case 650L	74	Diesel				2		2.0	7.78	9.52	9.24	71.49	114.79	20,370	3.95
580 BACKHOE	75%	488.25	Case 580N	78	Diesel				3		3.0	17.81	16.23	15.74	104.35	85.04	12,687	2.55
225 TRACK HOE	75%	488.25	Case CX210C	160	Diesel				3		3.0	17.72	13.94	13.52	65.90	110.85	15,827	3.18
BOBCAT	30%	130.2	Bobcat S130 Skid Steer Loader	49	Diesel				2		2.0	7.32	5.94	5.76	32.88	45.45	6,546	1.32
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used					0.0							
PLATE COMPACTORS	25%	542.5	Central Machinery 91762	6.5	Gas				10		10.0	21.93	0.52	0.48	1,340.68	8.78	4,733	0.98
SHEEPSFOOT	25%	108.5	Caterpillar CP54B	131	Diesel				2		2.0	17.23	21.63	20.98	74.95	185.35	41,820	8.01
DRUM ROLLER	25%	108.5	Caterpiller CS44	100	Diesel				2		2.0	13.31	20.02	19.42	129.62	141.05	29,773	5.70
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	8.31	8.49	8.24	53.16	104.09	15,399	3.08
375 COMPRESSOR	100%	2170	Sullair 375HH	139	Diesel	2	2	2	2	2	10.0	13.67	12.35	11.98	40.20	160.20	29,461	5.76
BUSHING GUN	10%	173.6	N/A	N/A	Air					8	8.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																		
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used					0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
220-T CRAWLER	50%	0	Manitowac 14000	340	Diesel	Not Used					0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used					0.0	13.75	13.28	12.88	40.42	155.14	33,115	6.37
80-TON PICKER	25%	434	Manitowac 2250	500	Diesel	2	2	2	2		8.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
65-TON PICKER	25%	0	Grove RT770E	240	Diesel	Not Used					0.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
25-TON PICKER	100%	868	Grove YB7725	130	Diesel					4	4.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel					2	2.0	10.16	11.98	11.62	65.67	111.85	22,344	4.30
3 -T FORK LIFT	100%	0	Cat PD10000	77	Diesel	Not Used					0.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
PILE DRIVER	100%	3472	Delmag D46-32/33	350	Diesel	4	4	4	4		16.0	62.61	67.58	65.55	407.31	935.17	139,995	27.65
F - PUMP EQUIP																		
2" CENT. PUMPS	5%	217	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	20.0	26.78	0.68	0.62	1,692.99	10.06	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	0	Lincoln Classic 300D	32.7	Diesel	Not Used					0.0	7.86	5.34	5.18	31.99	35.48	4,797	0.98
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	2170	Honda EM5000S	11.7	Gas					10	10.0	48.75	1.10	1.01	2,906.80	20.29	10,202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission (ton)						
						8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK older then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15.0	0.01	0.01	0.01	0.01	0.06	28	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	1085	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	10.0	0.03	0.03	0.03	0.05	0.20	92	0.01
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel					2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
CEMENT TRUCK	1%	4366	Mack Truck Granite Series	415	Diesel				1762	250	2012.0	0.19	0.22	0.21	0.76	1.94	640	0.11
CEMENT PUMP TRUCK	100%	4340	Putzmeister 70Z-Meter	450	Diesel				10	10	20.0	0.18	0.22	0.21	0.75	1.93	636	0.11
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	0.01	0.02	0.02	0.06	0.14	48	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	2	0.00
BUS	1%	10.85	Blue Bird Vision	260	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	1	0.00
FORKLIFT	100%	1085	Cat PD10000	77	Diesel	1	1	1	1	1	5.0	0.01	0.02	0.02	0.08	0.09	36	0.01
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	20.0	0.04	0.07	0.06	0.33	0.37	144	0.02
40' MANLIFT	100%	868	JLG 400S Telescopic Boom Lift	49	Diesel					4	4.0	0.02	0.01	0.01	0.06	0.05	6	0.00
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
100' MANLIFT	100%	0	JLG 1250AJP Articulating Boom Lift	87	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel					2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
TRACTOR/40' FLOAT	20%	434	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	10.0	0.01	0.01	0.01	0.04	0.08	13	0.00
UTILITY CARTS (SITE TRANSP)	10%	325.5	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	15.0	0.01	0.00	0.00	0.92	0.01	3	0.00
B - EARTH MOVING																		
FARM TRACTOR	100%	434	Kubota L4240	44	Diesel	Not Used			2		2.0	0.00	0.00	0.00	0.01	0.02	3	0.00
450 CASE DOZER	20%	86.8	Case 650L	74	Diesel				2		2.0	0.00	0.00	0.00	0.01	0.01	2	0.00
580 BACKHOE	75%	488.25	Case 580N	78	Diesel				3		3.0	0.01	0.01	0.01	0.06	0.05	7	0.00
225 TRACK HOE	75%	488.25	Case CX210C	160	Diesel				3		3.0	0.01	0.01	0.01	0.04	0.06	9	0.00
BOBCAT	30%	130.2	Bobcat S130 Skid Steer Loader	49	Diesel				2		2.0	0.00	0.00	0.00	0.00	0.01	1	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	542.5	Central Machinery 91762	6.5	Gas				10		10.0	0.01	0.00	0.00	0.80	0.01	3	0.00
SHEEPSFOOT	25%	108.5	Caterpillar CP54B	131	Diesel				2		2.0	0.00	0.00	0.00	0.01	0.02	5	0.00
DRUM ROLLER	25%	108.5	Caterpiller CS44	100	Diesel				2		2.0	0.00	0.00	0.00	0.02	0.02	4	0.00
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.13	0.25	37	0.01
375 COMPRESSOR	100%	2170	Sullair 375HH	139	Diesel	2	2	2	2	2	10.0	0.03	0.03	0.03	0.10	0.38	70	0.01
BUSHING GUN	10%	173.6	N/A	N/A	Air					8	8.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																		
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel						0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	50%	0	Manitowac 14000	340	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel						0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	25%	434	Manitowac 2250	500	Diesel	2	2	2	2		8.0	0.02	0.02	0.02	0.08	0.19	64	0.01
65-TON PICKER	25%	0	Grove RT770E	240	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	868	Grove YB7725	130	Diesel					4	4.0	0.01	0.02	0.02	0.05	0.12	49	0.01
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel					2	2.0	0.00	0.01	0.01	0.03	0.05	11	0.00
3 -T FORK LIFT	100%	0	Cat PD10000	77	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	3472	Delmag D46-32/33	350	Diesel	4	4	4	4		16.0	0.24	0.26	0.25	1.56	3.58	536	0.11
F - PUMP EQUIP																		
2" CENT. PUMPS	5%	217	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	20.0	0.01	0.00	0.00	0.40	0.00	1	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	0	Lincoln Classic 300D	32.7	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	2170	Honda EM5000S	11.7	Gas					10	10.0	0.12	0.00	0.00	6.95	0.05	24	0.01
											Total	*1.04*	*1.01*	*0.98*	*13.45*	*10.07*	*2599*	*0.47*

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.4 - Phase II LNG Tank Construction Emissions - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
DUMP TRUCK 6CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2										6.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT TRUCK	1%	5967.5	Mack Truck Granite Series	415	Diesel	250	250	250	250	250	250	250	250	250	250	250		2750.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT PUMP TRUCK	100%	23870	Putzmeister 70Z-Meter	450	Diesel	10	10	10	10	10	10	10	10	10	10	10		110.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FARM TRACTOR w/TRAILER	100%	7812	Kubota L4240	44	Diesel				4	4	4	4	4	4	4	4	4	36.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
40' MANLIFT	100%	6076	JLG 400S Telescopic Boom Lift	49	Diesel	4	4	4								8	8	28.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
60' MANLIFT	100%	3472	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4						16.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
100' MANLIFT	100%	3255	JLG 1250AJP Articulating Boom Lift	87	Diesel								5	5	5			15.0	19.32	15.05	14.60	98.87	88.84	12,198	2.44
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	23.79	17.71	17.18	81.06	158.04	26,243	5.10
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	6.92	8.63	8.38	60.52	110.47	20,373	3.81
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	16.17	15.11	14.66	96.80	78.44	12,692	2.51
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	16.19	13.12	12.72	59.05	101.17	15,832	3.13
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	6.41	5.41	5.25	29.06	43.63	6,549	1.29
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0							
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	21.12	0.52	0.48	1,331.65	8.19	4,734	0.98
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	15.83	20.46	19.85	65.93	159.22	41,824	7.79
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	11.96	18.50	17.95	114.58	121.88	29,777	5.54
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	13020	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.57	7.88	7.64	48.59	99.84	15,402	3.01
375 COMPRESSOR	100%	6076	Sullair 375HH	139	Diesel	2	2	2	2	2	2	2	2	2	2	2	6	28.0	12.77	11.82	11.46	36.21	140.82	29,464	5.63
BUSHING GUN	10%	520.8	N/A	N/A	Air	8	8	8										24.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	2387	Manitowac 2250	500	Diesel		2	2	2	2	2	2	2	2	2	2	2	22.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
220-T CRAWLER	50%	1193.5	Manitowac 14000	340	Diesel		1	1	1	1	1	1	1	1	1	1	1	11.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
TOWER CRANE	100%	9548	Terex SK 575-32	139	Diesel		4	4	4	4	4	4	4	4	4	4	4	44.0	12.69	12.70	12.32	35.77	133.50	33,118	6.20
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
65-TON PICKER	25%	976.5	Grove RT770E	240	Diesel				2	2	2	2	2	2	2	2	2	18.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	9.17	11.16	10.82	58.43	96.96	22,347	4.18
3 -T FORK LIFT	100%	3906	Cat PD10000	77	Diesel				2	2	2	2	2	2	2	2	2	18.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	59.17	64.25	62.32	370.44	857.50	140,006	27.21
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	325.5	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	2	2	2	2	2	2	2	2	2	30.0	26.29	0.68	0.62	1,687.58	9.70	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	9114	Electric Driven	N/A	Electric		2	2	2	2	4	4	4	4	4	4	10	42.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	1736	Lincoln Classic 300D	32.7	Diesel												8	8.0	6.82	4.87	4.72	28.30	34.05	4,800	0.96
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	45.91	1.10	1.01	2,875.10	18.19	10,205	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.02	0.02	0.02	0.03	0.11	67	0.01
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.06	0.06	0.06	0.08	0.36	222	0.04
DUMP TRUCK 6CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2										6.0	0.05	0.06	0.06	0.18	0.47	191	0.03
CEMENT TRUCK	1%	5967.5	Mack Truck Granite Series	415	Diesel	250	250	250	250	250	250	250	250	250	250	250		2750.0	0.25	0.28	0.27	0.81	2.17	874	0.15
CEMENT PUMP TRUCK	100%	23870	Putzmeister 70Z-Meter	450	Diesel	10	10	10	10	10	10	10	10	10	10	10		110.0	0.98	1.10	1.07	3.26	8.67	3496	0.60
FARM TRACTOR w/TRAILER	100%	7812	Kubota L4240	44	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.03	0.03	0.03	0.16	0.35	58	0.01
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.04	0.03	0.11	0.28	114	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4	0.00
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	2	0.00
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.03	0.12	0.15	86	0.01
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.09	0.12	0.11	0.48	0.60	345	0.06
40' MANLIFT	100%	6076	JLG 400S Telescopic Boom Lift	49	Diesel	4	4	4								8	8	28.0	0.10	0.06	0.06	0.38	0.35	44	0.01
60' MANLIFT	100%	3472	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4						16.0	0.06	0.03	0.03	0.21	0.20	25	0.01
100' MANLIFT	100%	3255	JLG 1250AJP Articulating Boom Lift	87	Diesel								5	5	5			15.0	0.07	0.05	0.05	0.35	0.32	44	0.01
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.21	0.24	0.23	0.71	1.89	763	0.13
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.03	0.02	0.02	0.09	0.18	30	0.01
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.00	0.00	0.03	0.05	6	0.00
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	13020	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.11	0.11	0.11	0.70	1.43	221	0.04
375 COMPRESSOR	100%	6076	Sullair 375HH	139	Diesel	2	2	2	2	2	2	2	2	2	2	2	6	28.0	0.09	0.08	0.08	0.24	0.94	197	0.04
BUSHING GUN	10%	520.8	N/A	N/A	Air	8	8	8										24.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	2387	Manitowac 2250	500	Diesel		2	2	2	2	2	2	2	2	2	2	2	22.0	0.09	0.08	0.08	0.35	1.35	247	0.05
220-T CRAWLER	50%	1193.5	Manitowac 14000	340	Diesel		1	1	1	1	1	1	1	1	1	1	1	11.0	0.05	0.04	0.04	0.17	0.67	124	0.02
TOWER CRANE	100%	9548	Terex SK 575-32	139	Diesel		4	4	4	4	4	4	4	4	4	4	4	44.0	0.13	0.13	0.13	0.38	1.41	349	0.07
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
65-TON PICKER	25%	976.5	Grove RT770E	240	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.02	0.02	0.02	0.03	0.13	83	0.01
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.16	0.18	0.18	0.35	1.01	583	0.09
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.05	0.06	0.06	0.34	0.56	128	0.02
3 -T FORK LIFT	100%	3906	Cat PD10000	77	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.03	0.04	0.04	0.18	0.23	129	0.02
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	325.5	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	2	2	2	2	2	2	2	2	2	30.0	0.01	0.00	0.00	0.61	0.00	2	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	9114	Electric Driven	N/A	Electric		2	2	2	2	4	4	4	4	4	4	10	42.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	1736	Lincoln Classic 300D	32.7	Diesel												8	8.0	0.01	0.01	0.01	0.05	0.07	9	0.00
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	1.32	0.03	0.03	82.53	0.52	293	0.06
																		Total	*4.08*	*2.94*	*2.85*	*92.92*	*24.49*	*8739*	*1.52*

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.5 - Phase II LNG Tank Construction Emissions - Year 2017

Magnolia LNG Project
Construction Equipment Utilization Matrix
LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT TRUCK	1%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FARM TRACTOR w/TRAILER	100%	10416	Kubota L4240	44	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	27.56	27.66	26.83	93.98	279.40	73,936	13.50
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
40' MANLIFT	100%	3472	JLG 400S Telescopic Boom Lift	49	Diesel	8	8											16.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
60' MANLIFT	100%	6944	JLG 600S Telescopic Boom Lift	49	Diesel			8	8	8	8							32.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
100' MANLIFT	100%	10416	JLG 1250AJP Articulating Boom Lift	87	Diesel							8	8	8	8	8	8	48.0	17.99	14.21	13.79	93.32	83.15	12,202	2.41
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	22.02	16.71	16.21	74.14	144.77	26,248	5.02
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	5.89	4.52	4.38	29.88	55.49	7,404	1.59
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	6.37	7.94	7.70	51.43	108.16	20,374	3.69
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	14.62	14.03	13.61	89.60	72.13	12,696	2.47
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	14.96	12.42	12.04	54.10	92.73	15,836	3.08
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	5.58	4.92	4.77	25.52	41.91	6,552	1.26
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0							
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	20.49	0.52	0.48	1,325.03	7.76	4,734	0.98
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	14.60	19.27	18.69	57.53	135.36	41,827	7.58
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	10.76	17.08	16.57	100.19	104.00	29,780	5.39
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	15624	Sullair 185	61	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	6.89	7.30	7.08	44.22	95.93	15,404	2.94
375 COMPRESSOR	100%	15624	Sullair 375HH	139	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	11.93	11.35	11.01	32.47	123.85	29,466	5.50
BUSHING GUN	10%	0	N/A	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used												0.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
220-T CRAWLER	50%	1302	Manitowac 14000	340	Diesel	2	2	2	2	2	2							12.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used												0.0	11.72	12.13	11.77	31.38	113.55	33,121	6.04
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
65-TON PICKER	25%	54.25	Grove RT770E	240	Diesel	1												1.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	8.29	10.39	10.08	51.49	83.03	22,350	4.08
3 -T FORK LIFT	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	56.26	61.29	59.45	336.86	784.31	140,014	26.78
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	260.4	DuroMax Portable 2" Water Pump	7	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	25.96	0.68	0.63	1,684.17	9.48	6,019	1.24
TEST PUMPS	100%	4340	Air Operated	N/A	Air								4	4	4	4	4	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	22134	Electric Driven	N/A	Electric	10	10	10	10	10	10	10	10	10	6	4	2	102.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	18228	Lincoln Classic 300D	32.7	Diesel	8	8	8	8	8	8	8	8	8	6	4	2	84.0	5.86	4.42	4.29	24.86	32.70	4,803	0.94
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	44.53	1.10	1.01	2,859.98	17.19	10,206	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.01	0.01	0.02	0.06	44	0.01
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.04	0.04	0.06	0.18	146	0.02
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	1%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FARM TRACTOR w/TRAILER	100%	10416	Kubota L4240	44	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.04	0.04	0.04	0.18	0.45	77	0.01
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.03	0.03	0.08	0.23	114	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4	0.00
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	2	0.00
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.02	0.09	0.11	86	0.01
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.08	0.10	0.10	0.36	0.42	345	0.05
40' MANLIFT	100%	3472	JLG 400S Telescopic Boom Lift	49	Diesel	8	8											16.0	0.05	0.03	0.03	0.20	0.19	25	0.01
60' MANLIFT	100%	6944	JLG 600S Telescopic Boom Lift	49	Diesel			8	8	8	8							32.0	0.11	0.06	0.06	0.40	0.38	51	0.01
100' MANLIFT	100%	10416	JLG 1250AJP Articulating Boom Lift	87	Diesel							8	8	8	8	8	8	48.0	0.21	0.16	0.16	1.07	0.95	140	0.03
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.21	0.22	0.21	0.53	1.51	763	0.13
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.03	0.02	0.02	0.09	0.17	30	0.01
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.00	0.00	0.03	0.05	6	0.00
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	15624	Sullair 185	61	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	0.12	0.13	0.12	0.76	1.65	265	0.05
375 COMPRESSOR	100%	15624	Sullair 375HH	139	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	0.21	0.20	0.19	0.56	2.13	507	0.09
BUSHING GUN	10%	0	N/A	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	50%	1302	Manitowac 14000	340	Diesel	2	2	2	2	2	2							12.0	0.05	0.04	0.04	0.17	0.66	135	0.03
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
65-TON PICKER	25%	54.25	Grove RT770E	240	Diesel	1												1.0	0.00	0.00	0.00	0.00	0.01	5	0.00
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.16	0.16	0.16	0.26	0.73	583	0.09
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.05	0.06	0.06	0.30	0.48	128	0.02
3 -T FORK LIFT	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.05	0.05	0.18	0.21	172	0.03
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	260.4	DuroMax Portable 2" Water Pump	7	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.01	0.00	0.00	0.48	0.00	2	0.00
TEST PUMPS	100%	4340	Air Operated	N/A	Air								4	4	4	4	4	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	22134	Electric Driven	N/A	Electric	10	10	10	10	10	10	10	10	10	6	4	2	102.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	18228	Lincoln Classic 300D	32.7	Diesel	8	8	8	8	8	8	8	8	8	6	4	2	84.0	0.12	0.09	0.09	0.50	0.66	96	0.02
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	1.28	0.03	0.03	82.09	0.49	293	0.06
																		Total	*2.85*	*1.51*	*1.47*	*88.41*	*11.73*	*4022*	*0.70*

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.6 - Phase III LNG Tank Construction Emissions - Year 2015

Magnolia LNG Project
Construction Equipment Utilization Matrix
Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year				Equipment Months	NONROAD Emission Factor (gram/hr)						
						9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																	
PICK-UP TRUCK or VAN newer then 2010	10%	238.7	GMC 1500	250	Diesel	2	2	2	5	11.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																	
2-T FLATBED TRUCK	50%	651	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3	6.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel				2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used				0.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel				100	100.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel				1	1.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FUEL TRUCK	30%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	4.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
MECH TRUCK	2%	17.36	GMC 1500	250	Diesel	1	1	1	1	4.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
BUS	1%	0	Blue Bird Vision	260	Diesel	Not Used				0.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
SCISSOR LIFT	50%	0	Electric Operated	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1736	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	8.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
40' MANLIFT	100%	434	JLG 400S Telescopic Boom Lift	49	Diesel				2	2.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used				0.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel				2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
TRACTOR/40' FLOAT	20%	347.2	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	8.0	25.74	18.79	18.23	88.89	172.15	26,237	5.18
UTILITY CARTS (SITE TRANSP)	10%	43.4	John Deere HPX 4 x 4	21	Gas				2	2.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86
B - EARTH MOVING																	
580 BACKHOE	100%	434	Case 580N	78	Diesel				2	2.0	17.81	16.23	15.74	104.35	85.04	12,687	2.55
225 TRACK HOE	100%	434	Case CX210C	160	Diesel				2	2.0	17.72	13.94	13.52	65.90	110.85	15,827	3.18
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used				0.0	24.38	26.28	25.49	84.59	248.66	73,154	13.19
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel				1	1.0	7.32	5.94	5.76	32.88	45.45	6,546	1.32
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used				0.0	3.11	3.15	3.06	15.81	30.37	4,739	0.93
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used				0.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used				0.0	21.93	0.52	0.48	1,340.68	8.78	4,733	0.98
C - AIR OP EQUIP																	
185 COMPRESSOR	100%	434	Sullair 185	61	Diesel				2	2.0	8.31	8.49	8.24	53.16	104.09	15,399	3.08
375 COMPRESSOR	100%	1736	Sullair 375HH	139	Diesel	2	2	2	2	8.0	13.67	12.35	11.98	40.20	160.20	29,461	5.76
D - HEAVY EQUIP																	
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	Not Used				0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	Not Used				0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
80-TON PICKER	100%	1736	Grove RT880E	275	Diesel	2	2	2	2	8.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used				0.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	3	9.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel	Not Used				0.0	10.16	11.98	11.62	65.67	111.85	22,344	4.30
PILE DRIVER	100%	1736	Delmag D46-32/33	350	Diesel	2	2	2	2	8.0	62.61	67.58	65.55	407.31	935.17	139,995	27.65
F - PUMP EQUIP																	
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas				4	4.0	26.78	0.68	0.62	1,692.99	10.06	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																	
RIG WELD TRUCK	100%	0	Electric Driven	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel	Not Used				0.0	7.86	5.34	5.18	31.99	35.48	4,797	0.98
I - ELECTRICAL EQUIP																	
GENERATOR'S 5KW	100%	868	Honda EM5000S	11.7	Gas	Not Used			4	4.0	48.75	1.10	1.01	2,906.80	20.29	10,202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year 9	10	11	12	Equipment Months	Annual Emission (ton) VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																	
PICK-UP TRUCK or VAN newer then 2010	10%	238.7	GMC 1500	250	Diesel	2	2	2	5	11.0	0.01	0.01	0.01	0.01	0.04	20	0.00
A - ROLLING EQUIP																	
2-T FLATBED TRUCK	50%	651	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3	6.0	0.02	0.02	0.02	0.03	0.12	55	0.01
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel				2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel				100	100.0	0.14	0.16	0.16	0.57	1.45	477	0.08
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel				1	1.0	0.01	0.01	0.01	0.04	0.10	32	0.01
FUEL TRUCK	30%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	4.0	0.01	0.01	0.01	0.05	0.12	38	0.01
MECH TRUCK	2%	17.36	GMC 1500	250	Diesel	1	1	1	1	4.0	0.00	0.00	0.00	0.00	0.00	1	0.00
BUS	1%	0	Blue Bird Vision	260	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	0	Electric Operated	N/A	electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1736	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	8.0	0.02	0.03	0.03	0.13	0.15	57	0.01
40' MANLIFT	100%	434	JLG 400S Telescopic Boom Lift	49	Diesel				2	2.0	0.01	0.00	0.00	0.03	0.03	3	0.00
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel				2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
TRACTOR/40' FLOAT	20%	347.2	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	8.0	0.01	0.01	0.01	0.03	0.07	10	0.00
UTILITY CARTS (SITE TRANSP)	10%	43.4	John Deere HPX 4 x 4	21	Gas				2	2.0	0.00	0.00	0.00	0.12	0.00	0	0.00
B - EARTH MOVING																	
580 BACKHOE	100%	434	Case 580N	78	Diesel				2	2.0	0.01	0.01	0.01	0.05	0.04	6	0.00
225 TRACK HOE	100%	434	Case CX210C	160	Diesel				2	2.0	0.01	0.01	0.01	0.03	0.05	8	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel				1	1.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																	
185 COMPRESSOR	100%	434	Sullair 185	61	Diesel				2	2.0	0.00	0.00	0.00	0.03	0.05	7	0.00
375 COMPRESSOR	100%	1736	Sullair 375HH	139	Diesel	2	2	2	2	8.0	0.03	0.02	0.02	0.08	0.31	56	0.01
D - HEAVY EQUIP																	
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	100%	1736	Grove RT880E	275	Diesel	2	2	2	2	8.0	0.04	0.04	0.04	0.08	0.31	148	0.02
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	3	9.0	0.03	0.04	0.04	0.11	0.27	109	0.02
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	1736	Delmag D46-32/33	350	Diesel	2	2	2	2	8.0	0.12	0.13	0.13	0.78	1.79	268	0.05
F - PUMP EQUIP																	
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas				4	4.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																	
RIG WELD TRUCK	100%	0	Electric Driven	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel	Not Used				0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																	
GENERATOR'S 5KW	100%	868	Honda EM5000S	11.7	Gas				4	4.0	0.05	0.00	0.00	2.78	0.02	10	0.00
										Total	***0.54***	***0.55***	***0.53***	***5.16***	***5.29***	***1435***	***0.26***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.7 - Phase III LNG Tank Construction Emissions - Year 2016

Magnolia LNG Project
Construction Equipment Utilization Matrix
Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Diesel	5	5	5	14	14	14	14	9	9	9	9	8	115.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	3	3	3	3	3	3	3	2	2	2	2	2	31.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel	2	2	2	2	2	2	2						14.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel								2	2	2	2	2	10.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel	100	100	100	100	100	100	100						700.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel	1	1	1	1	1	1	1						7.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
BUS	1%	2.17	Blue Bird Vision	260	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric				2	2	2	2	2	2	2	2	2	18.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	2	2	2	8	8	8	8	6	6	6	6	6	68.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4	4	4	4	4	4	36.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	23.79	17.71	17.18	81.06	158.04	26,243	5.10
UTILITY CARTS (SITE TRANSP)	10%	151.9	John Deere HPX 4 x 4	21	Gas	2	2	2	7	7	7	7	7	7	7	7	6	68.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59
B - EARTH MOVING																									
580 BACKHOE	100%	434	Case 580N	78	Diesel	2	2	2	2	2	2	2	2	2				18.0	16.17	15.11	14.66	96.80	78.44	12,692	2.51
225 TRACK HOE	100%	434	Case CX210C	160	Diesel	2	2	2	2	2	2	2	2	2				18.0	16.19	13.12	12.72	59.05	101.17	15,832	3.13
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel								1	1				2.0	23.02	24.53	23.79	69.68	207.46	73,158	12.76
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel	1	1	1	1	1	1	1	1	1				9.0	6.41	5.41	5.25	29.06	43.63	6,549	1.29
DITCH WITCH	10%	21.7	Bobcat E32	33.3	Diesel			1	1	1	1	1	1					6.0	2.63	2.75	2.66	13.29	28.93	4,741	0.91
GAS TAMPER	25%	108.5	Jumping Jack Tamper 115-130LB	4	Gas		2	2	2	2	2	2	2	2				16.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	217	Central Machinery 91762	6.5	Gas		4	4	4	4	4	4	4	4				32.0	21.12	0.52	0.48	1,331.65	8.19	4,734	0.98
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.57	7.88	7.64	48.59	99.84	15,402	3.01
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	12.77	11.82	11.46	36.21	140.82	29,464	5.63
D - HEAVY EQUIP																									
MODULE SET/HEAVY LIFT CRANE	10%	43.4	Manitowac 31000	600	Diesel				2	2	2	2	2	2	2	2	2	18.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
220-T CRAWLER	100%	868	Manitowac 14000	340	Diesel				4	4	4	4	4	4	4	4	4	36.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	2	2	2	3	3	3	3	3	3	3	3	3	33.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel							2	2	2	2	2	2	12.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
25-TON PICKER	100%	651	Grove YB7725	130	Diesel	3	3	3	3	3	3	8	8	8	5	5	5	57.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel							2	2	2	2	2	2	12.0	9.17	11.16	10.82	58.43	96.96	22,347	4.18
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	2	2	2										6.0	59.17	64.25	62.32	370.44	857.50	140,006	27.21
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4	4	4	4	4	48.0	26.29	0.68	0.62	1,687.58	9.70	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air							2	2	2				6.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
RIG WELD TRUCK	100%	868	Electric Driven	N/A	Electric		4	4	4	4	4	12	11	10	8	8	8	77.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel							4	4	4	4	4	4	24.0	6.82	4.87	4.72	28.30	34.05	4,800	0.96
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	4	4	4	6	6	6	10	10	10	6	6	6	78.0	45.91	1.10	1.01	2,875.10	18.19	10,205	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Diesel	5	5	5	14	14	14	14	9	9	9	9	8	115.0	0.01	0.01	0.01	0.01	0.04	26	0.00
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	3	3	3	3	3	3	3	2	2	2	2	2	31.0	0.01	0.01	0.01	0.01	0.04	28	0.00
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel	2	2	2	2	2	2	2						14.0	0.02	0.02	0.02	0.06	0.16	64	0.01
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel								2	2	2	2	2	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel	100	100	100	100	100	100	100						700.0	0.13	0.15	0.15	0.44	1.18	477	0.08
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel	1	1	1	1	1	1	1						7.0	0.01	0.01	0.01	0.03	0.08	32	0.01
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.01	0.02	10	0.00
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BUS	1%	2.17	Blue Bird Vision	260	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric				2	2	2	2	2	2	2	2	2	18.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.01	0.01	0.01	0.06	0.08	43	0.01
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	2	2	2	8	8	8	8	6	6	6	6	6	68.0	0.03	0.02	0.02	0.11	0.10	13	0.00
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.01	0.01	0.01	0.05	0.05	6	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.02	0.02	0.02	0.06	0.16	64	0.01
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	0.00	0.00	0.00	0.00	0.01	1	0.00
UTILITY CARTS (SITE TRANSP)	10%	151.9	John Deere HPX 4 x 4	21	Gas	2	2	2	7	7	7	7	7	7	7	7	6	68.0	0.00	0.00	0.00	0.01	0.01	1	0.00
B - EARTH MOVING																									
580 BACKHOE	100%	434	Case 580N	78	Diesel	2	2	2	2	2	2	2	2	2				18.0	0.01	0.01	0.01	0.05	0.04	6	0.00
225 TRACK HOE	100%	434	Case CX210C	160	Diesel	2	2	2	2	2	2	2	2	2				18.0	0.01	0.01	0.01	0.03	0.05	8	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel								1	1				2.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel	1	1	1	1	1	1	1	1	1				9.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	21.7	Bobcat E32	33.3	Diesel			1	1	1	1	1	1					6.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	108.5	Jumping Jack Tamper 115-130LB	4	Gas		2	2	2	2	2	2	2	2				16.0	0.01	0.00	0.00	0.07	0.00	0	0.00
PLATE COMPACTORS	25%	217	Central Machinery 91762	6.5	Gas		4	4	4	4	4	4	4	4				32.0	0.01	0.00	0.00	0.32	0.00	1	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.01	0.01	0.01	0.07	0.14	22	0.00
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	0.00	0.00	0.00	0.01	0.03	7	0.00
D - HEAVY EQUIP																									
MODULE SET/HEAVY LIFT CRANE	10%	43.4	Manitowac 31000	600	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.00	0.00	0.00	0.01	0.02	4	0.00
220-T CRAWLER	100%	868	Manitowac 14000	340	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.03	0.03	0.03	0.13	0.49	90	0.02
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	2	2	2	3	3	3	3	3	3	3	3	3	33.0	0.01	0.01	0.01	0.02	0.09	55	0.01
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel							2	2	2	2	2	2	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	651	Grove YB7725	130	Diesel	3	3	3	3	3	3	8	8	8	5	5	5	57.0	0.01	0.01	0.01	0.02	0.06	36	0.01
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel							2	2	2	2	2	2	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	2	2	2										6.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air							2	2	2				6.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
RIG WELD TRUCK	100%	868	Electric Driven	N/A	Electric		4	4	4	4	4	12	11	10	8	8	8	77.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel							4	4	4	4	4	4	24.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	4	4	4	6	6	6	10	10	10	6	6	6	78.0	0.07	0.00	0.00	4.13	0.03	15	0.00
																		Total	***0.43***	***0.35***	***0.34***	***5.78***	***2.89***	***1010***	***0.17***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.8 - Phase III LNG Tank Construction Emissions - Year 2017

Magnolia LNG Project
Construction Equipment Utilization Matrix
Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year										Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																							
PICK-UP TRUCK or VAN newer then 2010	10%	151.9	GMC 1500	250	Diesel	8	8	7	7	7	7	7	7	7	7	72.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
A - ROLLING EQUIP																							
2-T FLATBED TRUCK	50%	217	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FARM TRACTOR w/TRAILER	100%	434	Kubota L4240	44	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
CEMENT TRUCK	15%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
BUS	1%	2.17	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	27.56	27.66	26.83	93.98	279.40	73,936	13.50
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric	2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	6	6	6	6	6	6	6	4	2	2	50.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	8	8	8	8	8	8	8	8	4	2	70.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel	4	4	4	4	4	4	4	4	3	2	37.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	22.02	16.71	16.21	74.14	144.77	26,248	5.02
UTILITY CARTS (SITE TRANSP)	10%	108.5	John Deere HPX 4 x 4	21	Gas	6	6	5	5	5	5	5	5	5	5	52.0	5.89	4.52	4.38	29.88	55.49	7,404	1.59
B - EARTH MOVING																							
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used										0.0	14.62	14.03	13.61	89.60	72.13	12,696	2.47
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used										0.0	14.96	12.42	12.04	54.10	92.73	15,836	3.08
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used										0.0	21.82	22.77	22.09	55.54	169.94	73,162	12.36
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used										0.0	5.58	4.92	4.77	25.52	41.91	6,552	1.26
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used										0.0	2.22	2.37	2.30	11.03	27.59	4,742	0.88
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used										0.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used										0.0	20.49	0.52	0.48	1,325.03	7.76	4,734	0.98
C - AIR OP EQUIP																							
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	6	6	6	6	6	6	6	4	2	1	49.0	6.89	7.30	7.08	44.22	95.93	15,404	2.94
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	11.93	11.35	11.01	32.47	123.85	29,466	5.50
D - HEAVY EQUIP																							
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	2	2									4.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	4	4									8.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	3	3	3	3	3	3					18.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
35-TON PICKER	100%	434	Grove RT530E-2	164	Diesel	2	2	2	2	2	2	2				14.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
25-TON PICKER	100%	1085	Grove YB7725	130	Diesel	5	5	5	5	5	5	5	3	3		41.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2		18.0	8.29	10.39	10.08	51.49	83.03	22,350	4.08
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel											0.0	56.26	61.29	59.45	336.86	784.31	140,014	26.78
F - PUMP EQUIP																							
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4			32.0	25.96	0.68	0.63	1,684.17	9.48	6,019	1.24
TEST PUMPS	100%	434	Air Operated	N/A	Air			2	2	2	2	2	2			12.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																							
RIG WELD TRUCK	100%	1736	Electric Driven	N/A	Electric	8	8	8	8	8	8	6	4	2		60.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	868	Lincoln Classic 300D	32.7	Diesel	4	4	4	4	4	4	4	3	2		33.0	5.86	4.42	4.29	24.86	32.70	4,803	0.94
I - ELECTRICAL EQUIP																							
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	6	6	6	6	6	6	6	4	2		48.0	44.53	1.10	1.01	2,859.98	17.19	10,206	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year										Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																							
PICK-UP TRUCK or VAN newer then 2010	10%	151.9	GMC 1500	250	Diesel	8	8	7	7	7	7	7	7	7	7	72.0	0.00	0.00	0.00	0.00	0.02	13	0.00
A - ROLLING EQUIP																							
2-T FLATBED TRUCK	50%	217	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.00	0.00	0.00	0.01	0.02	18	0.00
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FARM TRACTOR w/TRAILER	100%	434	Kubota L4240	44	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.00	0.00	0.00	0.01	0.02	3	0.00
CEMENT TRUCK	15%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.01	0.02	10	0.00
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BUS	1%	2.17	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	217	Electric Operated	N/A	electric	2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	6	6	6	6	6	6	6	4	2	2	50.0	0.01	0.01	0.01	0.05	0.05	43	0.01
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	8	8	8	8	8	8	8	8	4	2	70.0	0.03	0.02	0.01	0.10	0.10	13	0.00
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel	4	4	4	4	4	4	4	4	3	2	37.0	0.01	0.01	0.01	0.05	0.05	6	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.02	0.02	0.02	0.04	0.13	64	0.01
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.01	1	0.00
UTILITY CARTS (SITE TRANSP)	10%	108.5	John Deere HPX 4 x 4	21	Gas	6	6	5	5	5	5	5	5	5	5	52.0	0.00	0.00	0.00	0.00	0.01	1	0.00
B - EARTH MOVING																							
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																							
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	6	6	6	6	6	6	6	4	2	1	49.0	0.01	0.01	0.01	0.06	0.14	22	0.00
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.01	0.03	7	0.00
D - HEAVY EQUIP																							
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	2	2									4.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	4	4									8.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	3	3	3	3	3	3					18.0	0.01	0.01	0.01	0.02	0.07	55	0.01
35-TON PICKER	100%	434	Grove RT530E-2	164	Diesel	2	2	2	2	2	2	2				14.0	0.01	0.01	0.01	0.01	0.03	24	0.00
25-TON PICKER	100%	1085	Grove YB7725	130	Diesel	5	5	5	5	5	5	5	3	3		41.0	0.02	0.02	0.02	0.03	0.08	61	0.01
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2		18.0	0.00	0.00	0.00	0.02	0.04	11	0.00
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel											0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																							
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4			32.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	434	Air Operated	N/A	air			2	2	2	2	2	2			12.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																							
RIG WELD TRUCK	100%	1736	Electric Driven	N/A	electric	8	8	8	8	8	8	6	4	2		60.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	868	Lincoln Classic 300D	32.7	Diesel	4	4	4	4	4	4	4	3	2		33.0	0.01	0.00	0.00	0.02	0.03	5	0.00
I - ELECTRICAL EQUIP																							
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	6	6	6	6	6	6	6	4	2		48.0	0.06	0.00	0.00	4.10	0.02	15	0.00
																Total	***0.21***	***0.13***	***0.13***	***4.63***	***0.85***	***372***	***0.06***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.9 - Phase IV Architectural - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

Architectural Buildings

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year								Equipment Months	NONROAD Emission Factor (gram/hr)						
						5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																					
PICK-UP TRUCK or VAN newer then 2010	10%	347.2	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	16.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
A - ROLLING EQUIP																					
2-T FLATBED TRUCK	50%	868	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	8.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
DUMP TRUCK 6CY	10%	65.1	Mack Truck Granite Series	415	Diesel	1	1	1						3.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
FORKLIFT	25%	434	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	8.0	7.48	10.14	9.83	41.50	52.52	30,043.46	4.84
EXTEND-A-FORKLIFT	100%	3472	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	2	16.0	7.48	10.14	9.83	41.50	52.52	30,043.46	4.84
CEMENT TRUCK	2%	208.32	Mack Truck Granite Series	415	Diesel	16	16	16						48.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
CEMENT PUMP TRUCK	100%	651	Putzmeister 70Z-Meter	450	Diesel	1	1	1						3.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
FUEL TRUCK	15%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	8.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
MECH TRUCK	2%	34.72	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	8.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
SCISSOR LIFT	100%	6944	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	4	32.0	115.8244	2.026913	1.86476	3982.1333	250.2594	22564.84811	4.6492
40' MANLIFT	100%	2170	JLG 400S Telescopic Boom Lift	49	Diesel				2	2	2	2	2	10.0	15.24	8.56	8.30	56.07	51.77	6,598.27	1.34
TRACTOR/40' FLOAT	10%	173.6	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	8.0	23.79	17.71	17.18	81.06	158.04	26,242.76	5.10
B - EARTH MOVING																					
450 CASE DOZER	25%	162.75	Case 650L	74	Diesel	1	1	1						3.0	6.92	8.63	8.38	60.52	110.47	20,372.52	3.81
580 BACKHOE	25%	162.75	Case 580N	78	Diesel	1	1	1						3.0	16.17	15.11	14.66	96.80	78.44	12,691.77	2.51
225 TRACK HOE	25%	162.75	Case CX210C	160	Diesel	1	1	1						3.0	16.19	13.12	12.72	59.05	101.17	15,831.97	3.13
DITCH WITCH	10%	65.1	Bobcat E32	33.3	Diesel	1	1	1						3.0	2.63	2.75	2.66	13.29	28.93	4,740.77	0.91
C - AIR OP EQUIP																					
185 COMPRESSOR	100%	3472	Sullair 185	61	Diesel	2	2	2	2	2	2	2	2	16.0	7.57	7.88	7.64	48.59	99.84	15,401.54	3.01
D - HEAVY EQUIP																					
25-TON PICKER	100%	2170	Grove YB7725	130	Diesel				2	2	2	2	2	10.0	14.01	16.01	15.53	30.48	88.38	50,792.76	8.22
G - WELDING EQUIP																					
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric				1	1	1	1	1	5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																					
GENERATOR'S 5KW	100%	5642	Honda EM5000S	11.7	Gas	2	2	2	4	4	4	4	4	26.0	45.91	1.10	1.01	2,875.10	18.19	10,204.61	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year								Equipment Months	Annual Emission (ton)						
						5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																					
PICK-UP TRUCK or VAN newer then 2010	10%	347.2	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	16.0	0.01	0.01	0.01	0.01	0.05	29.59	0.00
A - ROLLING EQUIP																					
2-T FLATBED TRUCK	50%	868	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	8.0	0.02	0.02	0.02	0.03	0.12	73.97	0.01
DUMP TRUCK 6CY	10%	65.1	Mack Truck Granite Series	415	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	9.54	0.00
FORKLIFT	25%	434	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.02	0.03	14.37	0.00
EXTEND-A-FORKLIFT	100%	3472	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	2	16.0	0.03	0.04	0.04	0.16	0.20	114.98	0.02
CEMENT TRUCK	2%	208.32	Mack Truck Granite Series	415	Diesel	16	16	16						48.0	0.01	0.01	0.01	0.03	0.08	30.51	0.01
CEMENT PUMP TRUCK	100%	651	Putzmeister 70Z-Meter	???	Diesel	1	1	1						3.0	0.03	0.03	0.03	0.09	0.24	95.36	0.02
FUEL TRUCK	15%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	8.0	0.01	0.01	0.01	0.04	0.09	38.14	0.01
MECH TRUCK	2%	34.72	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.00	0.00	2.96	0.00
SCISSOR LIFT	100%	6944	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	4	32.0	0.89	0.02	0.01	30.48	1.92	172.72	0.04
40' MANLIFT	100%	2170	JLG 400S Telescopic Boom Lift	49	Diesel				2	2	2	2	2	10.0	0.04	0.02	0.02	0.13	0.12	15.78	0.00
TRACTOR/40' FLOAT	10%	173.6	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.02	0.03	5.02	0.00
B - EARTH MOVING																					
450 CASE DOZER	25%	162.75	Case 650L	74	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	3.65	0.00
580 BACKHOE	25%	162.75	Case 580N	78	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.02	0.01	2.28	0.00
225 TRACK HOE	25%	162.75	Case CX210C	160	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	2.84	0.00
DITCH WITCH	10%	65.1	Bobcat E32	33.3	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.00	0.00	0.34	0.00
C - AIR OP EQUIP																					
185 COMPRESSOR	100%	3472	Sullair 185	61	Diesel	2	2	2	2	2	2	2	2	16.0	0.03	0.03	0.03	0.19	0.38	58.95	0.01
D - HEAVY EQUIP																					
25-TON PICKER	100%	2170	Grove YB7725	130	Diesel				2	2	2	2	2	10.0	0.03	0.04	0.04	0.07	0.21	121.50	0.02
G - WELDING EQUIP																					
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric				1	1	1	1	1	5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																					
GENERATOR'S 5KW	100%	5642	Honda EM5000S	11.7	Gas	2	2	2	4	4	4	4	4	26.0	0.29	0.01	0.01	17.88	0.11	63.46	0.01
														Total	***1.39***	***0.25***	***0.24***	***49.19***	***3.66***	***855.97***	***0.15***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.10 - Phase IV Architectural - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

Architectural Buildings

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	14.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
A - ROLLING EQUIP																				
2-T FLATBED TRUCK	50%	759.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
DUMP TRUCK 6CY	10%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FORKLIFT	25%	379.75	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	7.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
EXTEND-A-FORKLIFT	100%	3038	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	14.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
CEMENT TRUCK	2%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	???	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FUEL TRUCK	15%	227.85	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	7.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
MECH TRUCK	2%	30.38	GMC 1500	250	Gas	1	1	1	1	1	1	1	7.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
SCISSOR LIFT	100%	6076	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	28.0	113.42	2.03	1.87	3,909.01	244.50	22,456.27	4.63
40' MANLIFT	100%	0	JLG 400S Telescopic Boom Lift	49	Diesel	Not Used							0.0	14.00	8.07	7.82	51.94	50.18	6,602.02	1.32
TRACTOR/40' FLOAT	10%	151.9	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	7.0	22.02	16.71	16.21	74.14	144.77	26,248.14	5.02
B - EARTH MOVING																				
450 CASE DOZER	25%	0	Case 650L	74	Diesel	Not Used							0.0	6.37	7.94	7.70	51.43	108.16	20,374.18	3.69
580 BACKHOE	25%	0	Case 580N	78	Diesel	Not Used							0.0	14.62	14.03	13.61	89.60	72.13	12,696.45	2.47
225 TRACK HOE	25%	0	Case CX210C	160	Diesel	Not Used							0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used							0.0	2.22	2.37	2.30	11.03	27.59	4,742.02	0.88
C - AIR OP EQUIP																				
185 COMPRESSOR	100%	3038	Sullair 185	61	Diesel	2	2	2	2	2	2	2	14.0	6.89	7.30	7.08	44.22	95.93	15,403.60	2.94
D - HEAVY EQUIP																				
25-TON PICKER	100%	3038	Grove YB7725	130	Diesel	2	2	2	2	2	2	2	14.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
G - WELDING EQUIP																				
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric	1	1	1	1	1			5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																				
GENERATOR'S 5KW	100%	6076	Honda EM5000S	11.7	Gas	4	4	4	4	4	4	4	28.0	44.53	1.10	1.01	2,859.98	17.19	10,206.02	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	14.0	0.00	0.00	0.00	0.01	0.02	17.01	0.00
A - ROLLING EQUIP																				
2-T FLATBED TRUCK	50%	759.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.01	0.01	0.02	0.05	42.52	0.01
DUMP TRUCK 6CY	10%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FORKLIFT	25%	379.75	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.02	12.58	0.00
EXTEND-A-FORKLIFT	100%	3038	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	14.0	0.02	0.03	0.03	0.11	0.12	100.61	0.02
CEMENT TRUCK	2%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	???	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL TRUCK	15%	227.85	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.01	0.01	0.02	0.07	33.38	0.01
MECH TRUCK	2%	30.38	GMC 1500	250	Gas	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.00	0.00	2.59	0.00
SCISSOR LIFT	100%	6076	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	28.0	0.76	0.01	0.01	26.18	1.64	150.40	0.03
40' MANLIFT	100%	0	JLG 400S Telescopic Boom Lift	49	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRACTOR/40' FLOAT	10%	151.9	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.02	4.40	0.00
B - EARTH MOVING																				
450 CASE DOZER	25%	0	Case 650L	74	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
580 BACKHOE	25%	0	Case 580N	78	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225 TRACK HOE	25%	0	Case CX210C	160	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C - AIR OP EQUIP																				
185 COMPRESSOR	100%	3038	Sullair 185	61	Diesel	2	2	2	2	2	2	2	14.0	0.02	0.02	0.02	0.15	0.32	51.58	0.01
D - HEAVY EQUIP																				
25-TON PICKER	100%	3038	Grove YB7725	130	Diesel	2	2	2	2	2	2	2	14.0	0.05	0.05	0.05	0.08	0.21	170.10	0.03
G - WELDING EQUIP																				
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric	1	1	1	1	1			5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																				
GENERATOR'S 5KW	100%	6076	Honda EM5000S	11.7	Gas	4	4	4	4	4	4	4	28.0	0.30	0.01	0.01	19.16	0.12	68.36	0.01
													Total	***1.18***	***0.16***	***0.15***	***45.74***	***2.59***	***653.53***	***0.12***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.11 - Phase V Marine Work - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year			Equipment Months	NONROAD Emission Factor (gram/hr)						
						10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																
PICK-UP TRUCK or VAN newer then 2010	10%	130.2	GMC 1500	250	Diesel	2	2	2	6.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
A - ROLLING EQUIP																
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
DUMP TRUCK 14CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2	6.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
FARM WAGON w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used			0.0	4.43	4.49	4.35	22.50	43.22	6744	1.33
FUEL TRUCK	30%	195.3	Chevrolet C3500	397	Diesel	1	1	1	3.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
MECH TRUCK	2%	13.02	GMC 1500	250	Diesel	1	1	1	3.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
EXTEND-A-FORKLIFT	100%	0	JLG 8042 Sky Trak Telehandler	100	Diesel	Not Used			0.0	8.09	13.66	13.25	68.35	76.56	30042	5.10
1-T STAKEBED TRUCK	50%	651	Chevrolet C3500	397	Diesel	2	2	2	6.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
TRACTOR/40' FLOAT	10%	65.1	Mack Truck Pinnacle Series	505	Diesel	1	1	1	3.0	25.74	18.79	18.23	88.89	172.15	26237	5.18
UTILITY CARTS (SITE TRANSP)	10%	130.2	John Deere HPX 4 x 4	21	Gas	2	2	2	6.0	41.74	0.99	0.91	2,558.85	16.59	9039	1.86
B - EARTH MOVING																
DREDGER	100%	651	Typical	1450	Diesel	1	1	1	3.0	291.87	324.3	324.3	2702.5	14053	754765.01	1405.3
580 BACKHOE	100%	651	Case 580N	78	Diesel	1	1	1	3.0	17.81	16.23	15.74	104.35	85.04	12687	2.55
225 TRACK HOE	100%	1302	Case CX210C	160	Diesel	2	2	2	6.0	17.72	13.94	13.52	65.90	110.85	15827	3.18
EXTEND-A-HOE	100%	1302	Case CX210C	161	Diesel	2	2	2	6.0	17.72	13.94	13.52	65.90	110.85	15827	3.18
C - AIR OP EQUIP																
185 COMPRESSOR	100%	0	Sullair 185	61	Diesel	Not Used			0.0	8.31	8.49	8.24	53.16	104.09	15399	3.08
D - HEAVY EQUIP																
300-T CRAWLER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
80-TON PICKER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used			0.0	14.99	19.99	19.39	49.19	124.67	50790	8.67
25-TON PICKER	100%	0	Grove YB7725	130	Diesel	Not Used			0.0	14.99	19.99	19.39	49.19	124.67	50790	8.67
G - WELDING EQUIP																
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric				0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																
GENERATOR'S 5KW	100%	0	Honda EM5000S	11.7	Gas				0.0	48.75	1.10	1.01	2,906.80	20.29	10202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.

Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year			Equipment Months	Annual Emission (ton)						
						10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																
PICK-UP TRUCK or VAN newer then 2010	10%	130.2	GMC 1500	250	Diesel	2	2	2	6.0	0.00	0.00	0.00	0.01	0.02	11.10	0.00
A - ROLLING EQUIP																
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.01	0.06	27.74	0.00
DUMP TRUCK 14CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2	6.0	0.06	0.06	0.06	0.23	0.58	190.71	0.03
FARM WAGON w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL TRUCK	30%	195.3	Chevrolet C3500	397	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.03	0.09	28.61	0.01
MECH TRUCK	2%	13.02	GMC 1500	250	Diesel	1	1	1	3.0	0.00	0.00	0.00	0.00	0.00	1.11	0.00
EXTEND-A-FORKLIFT	100%	0	JLG 8042 Sky Trak Telehandler	100	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1-T STAKEBED TRUCK	50%	651	Chevrolet C3500	397	Diesel	2	2	2	6.0	0.03	0.03	0.03	0.11	0.29	95.35	0.02
TRACTOR/40' FLOAT	10%	65.1	Mack Truck Pinnacle Series	505	Diesel	1	1	1	3.0	0.00	0.00	0.00	0.01	0.01	1.88	0.00
UTILITY CARTS (SITE TRANSP)	10%	130.2	John Deere HPX 4 x 4	21	Gas	2	2	2	6.0	0.01	0.00	0.00	0.37	0.00	1.30	0.00
B - EARTH MOVING																
DREDGER	100%	651	Typical	1450	Diesel	1	1	1	3.0	0.21	0.23	0.23	1.94	10.08	541.62	1.01
580 BACKHOE	100%	651	Case 580N	78	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.07	0.06	9.10	0.00
225 TRACK HOE	100%	1302	Case CX210C	160	Diesel	2	2	2	6.0	0.03	0.02	0.02	0.09	0.16	22.72	0.00
EXTEND-A-HOE	100%	1302	Case CX210C	161	Diesel	2	2	2	6.0	0.03	0.02	0.02	0.09	0.16	22.72	0.00
C - AIR OP EQUIP																
185 COMPRESSOR	100%	0	Sullair 185	61	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D - HEAVY EQUIP																
300-T CRAWLER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
80-TON PICKER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25-TON PICKER	100%	0	Grove YB7725	130	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
G - WELDING EQUIP																
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric				0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																
GENERATOR'S 5KW	100%	0	Honda EM5000S	11.7	Gas				0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
									Total	***0.38***	***0.40***	***0.40***	***2.97***	***11.52***	***953.95***	***1.08***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.12 Phase V Marine Work - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	520.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	1302	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
DUMP TRUCK 14CY	100%	868	Mack Truck Granite Series	415	Diesel	2	2											4.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
FARM WAGON w/TRAILER	100%	2170	Kubota L4240	44	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	3.74	3.91	3.79	18.92	41.17	6745.63	1.29
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	7.48	10.14	9.83	41.50	52.52	30043.46	4.84
1-T STAKEBED TRUCK	50%	2604	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
TRACTOR/40' FLOAT	10%	260.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	23.79	17.71	17.18	81.06	158.04	26242.76	5.10
UTILITY CARTS (SITE TRANSP)	10%	520.8	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	5.91	4.53	4.39	30.24	55.48	7403.65	1.59
B - EARTH MOVING																									
DREDGER	100%	434	Typical	1450	Diesel	1	1											2.0	291.87	324.30	324.30	2702.50	14053.00	754765.01	1405.30
580 BACKHOE	100%	434	Case 580N	78	Diesel	1	1											2.0	16.17	15.11	14.66	96.80	78.44	12691.77	2.51
225 TRACK HOE	100%	868	Case CX210C	160	Diesel	2	2											4.0	16.19	13.12	12.72	59.05	101.17	15831.97	3.13
EXTEND-A-HOE	100%	868	Case CX210C	161	Diesel	2	2											4.0	16.19	13.12	12.72	59.05	101.17	15831.97	3.13
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	4340	Sullair 185	61	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	7.57	7.88	7.64	48.59	99.84	15401.54	3.01
D - HEAVY EQUIP																									
300-T CRAWLER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
80-TON PICKER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
35-TON PICKER	100%	2170	Grove RT530E-2	164	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	14.01	16.01	15.53	30.48	88.38	50792.76	8.22
25-TON PICKER	100%	4340	Grove YB7725	130	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	14.01	16.01	15.53	30.48	88.38	50792.76	8.22
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	4340	Electric Driven	N/A	Electric			2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	8680	Honda EM5000S	11.7	Gas			4	4	4	4	4	4	4	4	4	4	40.0	45.91	1.10	1.01	2875.10	18.19	10204.61	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.

Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	520.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.01	0.01	0.01	0.02	0.07	44.38	0.01
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	1302	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.03	0.03	0.04	0.18	110.96	0.02
DUMP TRUCK 14CY	100%	868	Mack Truck Granite Series	415	Diesel	2	2											4.0	0.04	0.04	0.04	0.12	0.32	127.14	0.02
FARM WAGON w/TRAILER	100%	2170	Kubota L4240	44	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.01	0.01	0.01	0.05	0.10	16.14	0.00
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.04	0.03	0.11	0.28	114.43	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4.44	0.00
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.04	0.05	0.05	0.20	0.25	143.73	0.02
1-T STAKEBED TRUCK	50%	2604	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.11	0.12	0.12	0.36	0.95	381.43	0.06
TRACTOR/40' FLOAT	10%	260.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.01	0.01	0.00	0.02	0.05	7.53	0.00
UTILITY CARTS (SITE TRANSP)	10%	520.8	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.00	0.00	0.00	0.02	0.03	4.25	0.00
B - EARTH MOVING																									
DREDGER	100%	434	Typical	1450	Diesel	1	1											2.0	0.14	0.16	0.16	1.29	6.72	361.08	0.67
580 BACKHOE	100%	434	Case 580N	78	Diesel	1	1											2.0	0.01	0.01	0.01	0.05	0.04	6.07	0.00
225 TRACK HOE	100%	868	Case CX210C	160	Diesel	2	2											4.0	0.02	0.01	0.01	0.06	0.10	15.15	0.00
EXTEND-A-HOE	100%	868	Case CX210C	161	Diesel	2	2											4.0	0.02	0.01	0.01	0.06	0.10	15.15	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	4340	Sullair 185	61	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.04	0.04	0.04	0.23	0.48	73.68	0.01
D - HEAVY EQUIP																									
300-T CRAWLER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.09	0.10	0.10	0.30	0.79	317.86	0.05
80-TON PICKER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.09	0.10	0.10	0.30	0.79	317.86	0.05
35-TON PICKER	100%	2170	Grove RT530E-2	164	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.03	0.04	0.04	0.07	0.21	121.50	0.02
25-TON PICKER	100%	4340	Grove YB7725	130	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.07	0.08	0.07	0.15	0.42	242.99	0.04
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	4340	Electric Driven	N/A	Electric			2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	8680	Honda EM5000S	11.7	Gas			4	4	4	4	4	4	4	4	4	4	40.0	0.44	0.01	0.01	27.51	0.17	97.64	0.02
																		Total	***1.21***	***0.85***	***0.83***	***30.93***	***12.04***	***2,523.40***	***1.04***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.13 Phase V Marine Work - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	217	GMC 1500	250	Gas	2	2	2	2	2	10.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
DUMP TRUCK 14CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used					0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FARM WAGON w/TRAILER	100%	1085	Kubota L4240	44	Diesel	1	1	1	1	1	5.0	3.15	3.37	3.27	15.69	39.25	6,747.42	1.26
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
EXTEND-A-FORKLIFT	100%	2170	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	10.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
1-T STAKEBED TRUCK	50%	1085	Chevrolet C3500	397	Diesel	2	2	2	2	2	10.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
TRACTOR/40' FLOAT	10%	108.5	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	5.0	22.02	16.71	16.21	74.14	144.77	26,248.14	5.02
UTILITY CARTS (SITE TRANSP)	10%	217	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	10.0	5.89	4.52	4.38	29.88	55.49	7,403.72	1.59
B - EARTH MOVING																		
DREDGER	100%	0	Typical	1450	Diesel	Not Used					0.0	291.87	324.3	324.3	2702.5	14053	754765.01	1405.3
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used					0.0	14.62	14.03	13.61	89.60	72.13	12,696.45	2.47
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used					0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
EXTEND-A-HOE	100%	0	Case CX210C	161	Diesel	Not Used					0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	6.89	7.30	7.08	44.22	95.93	15,403.60	2.94
D - HEAVY EQUIP																		
300-T CRAWLER	100%	1085	Manitowac 2250	500	Diesel	1	1	1	1	1	5.0	36.34	38.53	37.38	92.23	262.71	132884.93	21.86
80-TON PICKER	100%	651	Manitowac 2250	500	Diesel	1	1	1			3.0	36.34	38.53	37.38	92.23	262.71	132884.93	21.86
35-TON PICKER	100%	1085	Grove RT530E-2	164	Diesel	1	1	1	1	1	5.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	2	1	9.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	2170	Electric Driven	N/A	Electric	2	2	2	2	2	10.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	3472	Honda EM5000S	11.7	Gas	4	4	4	2	2	16.0	44.53	1.10	1.01	2,859.98	17.19	10,206.02	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.

Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.

Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission(ton)						
						1	2	3	4	5		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	217	GMC 1500	250	Gas	2	2	2	2	2	10.0	0.00	0.00	0.00	0.01	0.02	18.49	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5.0	0.01	0.01	0.01	0.01	0.05	46.23	0.01
DUMP TRUCK 14CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FARM WAGON w/TRAILER	100%	1085	Kubota L4240	44	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.02	0.05	8.07	0.00
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	0.01	0.01	0.01	0.03	0.09	47.68	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	1.85	0.00
EXTEND-A-FORKLIFT	100%	2170	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.08	0.09	71.87	0.01
1-T STAKEBED TRUCK	50%	1085	Chevrolet C3500	397	Diesel	2	2	2	2	2	10.0	0.04	0.05	0.04	0.11	0.31	158.93	0.03
TRACTOR/40' FLOAT	10%	108.5	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.01	0.02	3.14	0.00
UTILITY CARTS (SITE TRANSP)	10%	217	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	10.0	0.00	0.00	0.00	0.01	0.01	1.77	0.00
B - EARTH MOVING																		
DREDGER	100%	0	Typical	1450	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXTEND-A-HOE	100%	0	Case CX210C	161	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.11	0.23	36.85	0.01
D - HEAVY EQUIP																		
300-T CRAWLER	100%	1085	Manitowac 2250	500	Diesel	1	1	1	1	1	5.0	0.04	0.05	0.04	0.11	0.31	158.93	0.03
80-TON PICKER	100%	651	Manitowac 2250	500	Diesel	1	1	1			3.0	0.03	0.03	0.03	0.07	0.19	95.36	0.02
35-TON PICKER	100%	1085	Grove RT530E-2	164	Diesel	1	1	1	1	1	5.0	0.02	0.02	0.02	0.03	0.08	60.75	0.01
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	2	1	9.0	0.03	0.03	0.03	0.05	0.14	109.35	0.02
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	2170	Electric Driven	N/A	Electric	2	2	2	2	2	10.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	3472	Honda EM5000S	11.7	Gas	4	4	4	2	2	16.0	0.17	0.00	0.00	10.95	0.07	39.06	0.01
											Total	***0.40***	***0.25***	***0.24***	***11.58***	***1.66***	***858.33***	***0.14***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.14 Phase VI Miscellaneous - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	NONROAD Emission Factor (gram/hr)						
						6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	716.1	GMC 1500	250	Gas	4	4	5	5	5	5	5	33.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																				
WATER TRUCK	5%	75.95	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
FORKLIFT (WHSE Operations)	100%	3038	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	14.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
EXTEND-A-FORKLIFT (WHSE Operations)	100%	1519	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	7.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
UTILITY CARTS (SITE TRANSP)	10%	716.1	John Deere HPX 4 x 4	21	Gas	4	4	5	5	5	5	5	33.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86

Note: values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % time and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operatoin	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	Annual Emission (ton)						
						6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	716.1	GMC 1500	250	Gas	4	4	5	5	5	5	5	33.0	0.02	0.02	0.02	0.03	0.13	61.03	0.01
A - ROLLING EQUIP																				
WATER TRUCK	5%	75.95	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.03	6.19	0.00
FORKLIFT (WHSE Operations)	100%	3038	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	14.0	0.03	0.05	0.04	0.23	0.26	100.60	0.02
EXTEND-A-FORKLIFT (WHSE Operations)	100%	1519	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.02	0.02	0.11	0.13	50.30	0.01
UTILITY CARTS (SITE TRANSP)	10%	716.1	John Deere HPX 4 x 4	21	Gas	4	4	5	5	5	5	5	33.0	0.03	0.00	0.00	2.02	0.01	7.14	0.00
													Total	***0.09***	***0.09***	***0.09***	***2.40***	***0.56***	***225.26***	***0.04***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

This page left blank intentionally.

Table 9.A.15 Phase VI Miscellaneous - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1692.6	GMC 1500	250	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
UTILITY CARTS (SITE TRANSP)	10%	1692.6	John Deere HPX 4 x 4	21	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1692.6	GMC 1500	250	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	0.04	0.04	0.04	0.05	0.23	144.25	0.02
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.02	0.05	10.61	0.00
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.06	0.06	0.24	0.30	172.47	0.03
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.03	0.12	0.15	86.24	0.01
UTILITY CARTS (SITE TRANSP)	10%	1692.6	John Deere HPX 4 x 4	21	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	0.01	0.01	0.01	0.06	0.10	13.81	0.00
																		Total	***0.12***	***0.14***	***0.13***	***0.48***	***0.83***	***427.39***	***0.07***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

This page left blank intentionally.

Table 9.A.16 Phase VI Miscellaneous - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1974.7	GMC 1500	250	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	27.56	27.66	26.83	93.98	279.40	73,936.37	13.50
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
UTILITY CARTS (SITE TRANSP)	10%	1974.7	John Deere HPX 4 x 4	21	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	5.89	4.52	4.38	29.88	55.49	7,403.72	1.59

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1974.7	GMC 1500	250	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	0.03	0.03	0.03	0.05	0.14	110.56	0.02
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.01	0.04	10.61	0.00
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.05	0.05	0.18	0.21	172.48	0.03
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.02	0.09	0.11	86.24	0.01
UTILITY CARTS (SITE TRANSP)	10%	1974.7	John Deere HPX 4 x 4	21	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	0.01	0.01	0.01	0.07	0.12	16.12	0.00
																		Total	***0.11***	***0.12***	***0.12***	***0.40***	***0.62***	***396.01***	***0.06***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

This page left blank intentionally.

Table 9.A.17 - Construction Material Transport by Tug/Barge in Year 2016

			Emissions (tons in 2016)											Engine
Marine Operations		kilowatts (each)	**VOC**	**PM10**	**PM2.5**	**CO**	**NOx**	**CO2e**	**CO2**	**N2O**	**CH4**	**SO2**	**PM**	**Load Factor**
	Tugs (3100 hp) - barge push	2312	0.52	0.58	0.58	4.82	25.06	1345.71	1330.12	0.04	0.17	2.51	0.58	0.85
	Tugs (3100 hp) - idle mode	578	0.02	0.02	0.02	0.14	0.74	39.58	39.12	0.00	0.01	0.07	0.02	0.25
Subtotal Vessels			**0.54**	**0.60**	**0.60**	**4.96**	**25.80**	**1385.29**	**1369.24**	**0.04**	**0.18**	**2.58**	**0.60**	

This page left blank intentionally.

Table 9.A.18 - Tug/Barge Construction Material Transport Activity List

CONSTRUCTION PHASE	Activity	Number of Round Trips	Pieces of Equipment	Horsepower	Fuel Type	Distance Each Trip	Average Speed (mph)	Hours of Operation	Total Idle Hours (estimate)	
Pile Delivery	Transport concrete LNG tank storage piles from point 7 miles away, RT = 14 miles	5	1	3100	Diesel	14	2	35	3.5	
	Transport liquefaction modules from point up to 50 miles away, RT = 100 miles	16	1	3100	Diesel	100	2	250	25	
	Transport rock seawall armoring from point up to 50 miles away, RT = 100 miles	12	1	3100	Diesel	100	2	250	25	
	Transport sheet pile from point 50 miles away, RT = 100 miles	4	1	3100	Diesel	100	2	250	25	
	Transport marine pilings and mooring assemblies from point 7 miles away, RT = 14 miles	4	1	3100	Diesel	14	2	35	3.5	
	Transport concrete balance of plant storage piles from point 7 miles away, RT = 14 miles	5	1	3100	Diesel	14	2	35	3.5	
	Provision for Miscellaneous Deliveries	4	1	3100	Diesel	14	2	35	3.5	
	Total	50						890	89	

Rev: 10/30/2013

Assumptions:

Average trip speed 2 mph @ 85% engine load
All trips occur in year 2016
Tug present while barges being loaded/unloaded used intermittently to position barges for loading /unloading
One tug assigned to project
Idle time is assumed 10% of hours of operation

This page left blank intentionally.

Table 9.A.19 - Tug and Dredge Vessel Emission Factors

		Emission Factors (g/kw-hr)										engine emiss tier	engine power cat
	Kilowatts (each)	**VOC**	**PM10**	**PM2.5**	**CO**	**NOx**	**CO2**	**N2O**	**CH4**	**SO2**	**PM**		
Tugs (3100 hp) - barge push	2312	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1
Tugs (3100 hp) - idle mode (25% of full kw)	578	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1
Dredger - Medium (1450 hp)	1081	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1

Data Source: ICF Best Practices for Port Emission Inventories, Table 3-8 Harbor Craft Emission Factors
Notes: according to ICF Best practices, most tugs are Cat 1 (75% to 90%) with remainder Cat 2 (however, it is very port/harbor specific).

Jekyll Island
1,450 HP; 1,081 kW; assume Tier 0
14" Cutter Suction Head Dredge

This page left blank intentionally.

Table 9.A.20 - Fugitive Dust Emissions from General Site Work and Earth Moving

	General Construction Site Work				Earth Moving			Summary		
	From RR1	Estimated	PM10 Emiss Factor	PM 10 emiss		EF	PM10	**Total PM10**	PM2.5/PM10	**Total PM2.5**
Site	Acres disturbed	Duration (months)	ton/acre/month	tons	cu yds	ton/1000 cu yd	(tons)	**(tons)**	ratio	**(tons)**
Magnolia 2015	108	6	0.011	7.1	131200	0.059	7.7	**14.9**	0.1	**1.5**
Magnolia 2016	108	12	0.011	14.3	0	0.059	0.0	**14.3**	0.1	**1.4**
Magnolia 2017	108	12	0.011	14.3	0	0.059	0.0	**14.3**	0.1	**1.4**

Note: General construction site work and earth moving emission factors used are from Table 3-2, Level 2 basis from Western Regional Air Partnership Fugitive Dust Handbook (WRAP FDH) (revised 2006). PM2.5 to PM10 ratio based on WRAP FDH as well.

131200 cubic yards soil excavated from upland areas and placed on site.

This page left blank intentionally.

Table 9.A.21 - Fugitive Dust Emissions from Unpaved Roads

Site										Emissions (tons)		
	VMT	% Paved	% Unpaved	TSP Paved	TSP Unpaved	PM10 Paved	PM10 Unpaved	PM2.5 Paved	PM2.5 Unpaved	TSP Total	PM10 Total	PM2.5 Total
Heavy Haul Road	60	0	100	0.00	0.33	0.00	0.09	0.00	0.01	0.33	0.09	0.01

Note: VMT estimated based on use of 100 round trips of 0.6 miles each RT with SPMTs. Heavy haul road is 1,500 foot road from Dynamic Industries Yard.

Paved Road EF Input Parameter	Value	Parameter Value Data source
Particle Size multiplier PM10	0.0022	From AP-42, Table 13.2.1-1
Particle Size multiplier PM2.5	0.00054	From AP-42, Table 13.2.1-1
Particle Size multiplier TSP	0.011	From AP-42, Table 13.2.1-1
Road surface silt (g/m2)	0.2	From WRAP Table 5-2, baseline silt loading for public paved road with ADT 500 to 5,000
W average vehicle wt (tons)	2.5	Based on estimate of typical weight of cars and SUVs
Calculated PM10 EF (lb/VMT)	**0.001295**	Equation from AP-42 section 13.2.1 Paved Roads
Calculated PM2.5 EF (lb/VMT)	**0.000318**	Equation from AP-42 section 13.2.1 Paved Roads
Calculated TSP EF (lb/VMT)	**0.006475**	Equation from AP-42 section 13.2.1 Paved Roads

UnPaved Road EF Input Parameter	Value	Parameter Value Data source
Particle Size multiplier PM10	1.5	From AP-42, Table 13.2.2-2
Particle Size multiplier PM2.5	0.15	From AP-42, Table 13.2.2-2
Particle Size multiplier TSP	4.9	From AP-42, Table 13.2.2-2
Road surface silt (%)	8.5	From AP-42, Table 13.2.2-1, Construction Sites scraper routes mean value
W average vehicle wt (tons)	30	Based on estimate of weight of SPMT
Constant "a" for equation PM10	0.9	From AP-42, Table 13.2.2-2
Constant "a" for equation PM2.5	0.9	From AP-42, Table 13.2.2-2
Constant "a" for equation TSP	0.7	From AP-42, Table 13.2.2-2
Constant "b" for equation PM10	0.45	From AP-42, Table 13.2.2-2
Constant "b" for equation PM2.5	0.45	From AP-42, Table 13.2.2-2
Constant "b" for equation TSP	0.45	From AP-42, Table 13.2.2-2
Calculated PM10 EF (lb/VMT)	**3.099597**	Equation from AP-42 section 13.2.2 Unpaved Roads
Calculated PM2.5 EF (lb/VMT)	**0.30996**	Equation from AP-42 section 13.2.2 Unpaved Roads
Calculated TSP EF (lb/VMT)	**10.84832**	Equation from AP-42 section 13.2.2 Unpaved Roads

This page left blank intentionally.

Table 9.A.22 - On-Road Worker Commute Emissions

	From MOVES for Calcasieu Parish		Emission Factor Calculated		2015			2016			2017		
Pollutant	emiss (g)	Distance (mi)	grams/mi	miles/yr	gm/yr	tons/yr	miles/yr	gm/yr	tons/yr	miles/yr	gm/yr	tons/yr
CO	99624395.59	84673680.67	1.17656862	1259356	1481719	1.6334	2158896	2540089	2.8000	2158896	2540089	2.8000
NOx	7550948.599	84673680.67	0.089177045	1259356	112306	0.1238	2158896	192524	0.2122	2158896	192524	0.2122
SO2	329748.1978	84673680.67	0.003894341	1259356	4904	0.0054	2158896	8407	0.0093	2158896	8407	0.0093
VOC	1297832.909	84673680.67	0.015327465	1259356	19303	0.0213	2158896	33090	0.0365	2158896	33090	0.0365
CO2e	14531201485	84673680.67	171.614147	1259356	216123306	238.2403	2158896	370497096	408.4120	2158896	370497096	408.4120
PM10exh	212805.0997	84673680.67	0.002513238	1259356	3165	0.0035	2158896	5426	0.0060	2158896	5426	0.0060
PM10brake	518493.8521	84673680.67	0.006123436	1259356	7712	0.0085	2158896	13220	0.0146	2158896	13220	0.0146
PM10tire	241995.4865	84673680.67	0.002857978	1259356	3599	0.0040	2158896	6170	0.0068	2158896	6170	0.0068
PM25exh	195953.1481	84673680.67	0.002314216	1259356	2914	0.0032	2158896	4996	0.0055	2158896	4996	0.0055
PM25brake	135731.3843	84673680.67	0.001602994	1259356	2019	0.0022	2158896	3461	0.0038	2158896	3461	0.0038
PM25tire	58032.49005	84673680.67	0.000685366	1259356	863	0.0010	2158896	1480	0.0016	2158896	1480	0.0016
Total PM10	(sum of PM10 exh, PM10 brake, PM10 tire)				14476	0.0160		24816	0.0274		24816	0.0274
Total PM2.5	(sum of PM2.5 exh, PM2.5 brake, PM2.5 tire)				5796	0.0064		9936	0.0110		9936	0.0110

Note: car commuting mileage for construction workers provided by S&K construction engineering estimate

179908 miles per month for 31 months

7 months in 2015

12 months in 2016

12 months in 2017

This page left blank intentionally.

Appendix 9.B
Operational Emissions

This page left blank intentionally.

Appendix 9.B.1

Operational Emissions Calculations

This page left blank intentionally.

Table No	Table Name
Table 1	Facility-Wide Emissions
Table 2	Emissions for Each LNG Train
Table 3	Emissions for Gas Turbine
Table 4	Emissions for Thermal Oxidizer - Design/Maximum Conditions
Table 5	Emissions for Thermal Oxidizer - Average Conditions
Table 6	Emissions for Auxiliary Boiler
Table 7	Auxiliary Boiler - Case 1 - Avg Feed Gas Base Case
Table 8	Auxiliary Boiler - Case 2 - Rich Feed Gas Case
Table 9	Auxiliary Boiler - Case 3 - Ship Loading Case
Table 10	Auxiliary Boiler - Case 4 - High Inerts Feed Gas Case
Table 11	Emissions for Ammonia Vent
Table 12	Emissions for Warm Flare
Table 14	Emissions for Emergency Generator Engine
Table 15	Emissions for Emergency Fire Pump
Table 16	Emissions for Deluge Pump
Table 17	Process Streams and Piping Component Counts
Table 18	Fugitive Emissions for Piping Components
Table 19	LNG Vessel and Tug Boat Operational Emissions
Table 20	Operational Mobile Sources - Magnolia LNG

NOTE: Tables 17 and 18 are PRIVILEGED and are provided separately in Appendix 9.B.2.

This page left blank intentionally.

Table 1
Facility-Wide Emissions
Magnolia LNG

		Annual Emissions (tpy)																
		Stationary Sources													Mobile Sources			
Pollutant Type	**Pollutant**	**LNG Train 1**	**LNG Train 2**	**LNG Train 3**	**LNG Train 4**	**Warm Gas Flare**	**Cold Gas Flare**	**Emergency Generator**	**Emergency Fire Pump 1**	**Emergency Fire Pump 2**	**Deluge Pump 1**	**Deluge Pump 2**	**Fugitive Emissions**	**SUBTOTAL**	**LNG Vessels and Tug Boats**	**Operational Mobile Sources**	**SUBTOTAL**	**TOTAL**
Criteria	NO_x	282.94	282.94	282.94	282.94	8.31	4.51	3.55	0.59	0.59	2.12	2.12		**1,153.55**	328.68	66.09	**394.77**	**1,548.32**
	CO	182.27	182.27	182.27	182.27	45.19	24.54	1.92	0.51	0.51	1.15	1.15		**804.04**	42.10	6.26	**48.37**	**852.41**
	VOC	13.15	13.15	13.15	13.15	0.72	0.01	0.35	0.06	0.06	0.21	0.21	14.69	**68.91**	18.94	2.51	**21.45**	**90.37**
	PM	21.50	21.50	21.50	21.50	1.01	0.55	0.11	0.03	0.03	0.07	0.07		**87.88**	14.66	3.61	**18.27**	**106.15**
	PM_{10}	21.50	21.50	21.50	21.50	1.01	0.55	0.09	0.02	0.02	0.05	0.05		**87.82**	14.66	3.61	**18.27**	**106.10**
	$PM_{2.5}$	21.50	21.50	21.50	21.50	1.01	0.55	0.08	0.02	0.02	0.05	0.05		**87.78**	14.66	3.61	**18.27**	**106.05**
	SO_2	33.45	33.45	33.45	33.45			0.004	0.001	0.001	0.002	0.002		**133.80**	2.63	0.03	**2.66**	**136.46**
HAPs	Acetaldehyde	0.11	0.11	0.11	0.11									**0.45**				**0.45**
	Acrolein	0.02	0.02	0.02	0.02									**0.07**				**0.07**
	Benzene	0.07	0.07	0.07	0.07	0.0042	0.00005	0.002	0.0006	0.0006	0.001	0.001	0.02	**0.32**				**0.32**
	Ethylbenzene	0.09	0.09	0.09	0.09									**0.36**				**0.36**
	Formaldehyde	2.02	2.02	2.02	2.02	0.01	0.01		0.0007	0.0007				**8.10**				**8.10**
	Hexane	0.32	0.32	0.32	0.32	0.046	0.0006						0.24	**1.57**				**1.57**
	Napthalene	0.004	0.004	0.004	0.004									**0.01**				**0.01**
	PAH	0.006	0.006	0.006	0.006									**0.02**				**0.02**
	Toluene	0.38	0.38	0.38	0.38	0.0016	0.0000	0.0007					0.01	**1.54**				**1.54**
	Xylenes	0.20	0.20	0.20	0.20	0.0019	0.0000						0.01	**0.80**				**0.80**
	Total HAPs	**3.22**	**3.22**	**3.22**	**3.22**	**0.064**	**0.006**	**0.002**	**0.001**	**0.001**	**0.001**	**0.001**	**0.28**	**13.25**				**13.25**
Non-HAP TACs	Ammonia	1.45	1.45	1.45	1.45								1.54	**7.33**				**7.33**
	H_2S	0.96	0.96	0.96	0.96									**3.83**				**3.83**
Greenhouse Gas	CO_2	516,534.36	516,534.36	516,534.36	516,534.36	15,878.92	8,623.47	384.05	98.75	98.75	201.21	201.21	1.93	**2,091,625.72**	21,231.95	3,451.55	**24,683.50**	**2,116,309.23**
	N_2O	10.38	10.38	10.38	10.38	0.03	0.01	0.003	0.001	0.001	0.002	0.002		**41.57**	0.41	0.10	**0.51**	**42.08**
	CH_4	72.33	72.33	72.33	72.33	26.89	13.87	0.02	0.005	0.005	0.010	0.010	88.79	**418.91**	1.65	0.45	**2.10**	**421.02**

		Annual Emissions (ton CO_2e/yr)																
		Stationary Sources													Mobile Sources			
	Pollutant	**LNG Train 1**	**LNG Train 2**	**LNG Train 3**	**LNG Train 4**	**Process Flare**	**Marine Flare**	**Emergency Generator**	**Emergency Fire Pump 1**	**Emergency Fire Pump 2**	**Deluge Pump 1**	**Deluge Pump 2**	**Fugitive Emissions**	**SUBTOTAL**	**LNG Vessels and Tug Boats**	**Operational Mobile Sources**	**SUBTOTAL**	**TOTAL**
Greenhouse Gas (CO_2e)	CO_2	516,534.36	516,534.36	516,534.36	516,534.36	15,878.92	8,623.47	384.05	98.75	98.75	201.21	201.21	1.93	**2,091,625.72**	21,231.95	3,451.55	**24,683.50**	**2,116,309.23**
	N_2O	3,093.05	3,093.05	3,093.05	3,093.05	8.01	4.35	0.92	0.24	0.24	0.48	0.48		**12,386.93**	122.25	29.81	**152.06**	**12,538.99**
	CH_4	1,808.17	1,808.17	1,808.17	1,808.17	672.34	346.80	0.47	0.12	0.12	0.25	0.25	2,219.74	**10,472.79**	41.33	11.26	**52.59**	**10,525.38**
	Total GHGs	**521,435.58**	**521,435.58**	**521,435.58**	**521,435.58**	**16,559.28**	**8,974.62**	**385.43**	**99.11**	**99.11**	**201.94**	**201.94**	**2,221.67**	**2,114,485.44**	**21,395.53**	**3,492.62**	**24,888.15**	**2,139,373.59**

Table 2
Emissions for Each LNG Train
Magnolia LNG

Pollutant Type	Pollutant	Annual Emissions (tpy)					
		Turbine A	**Turbine B**	**Thermal Oxidizer**	**Auxiliary Boiler**	**Ammonia Vent**	**TOTAL**
Criteria	NO_x	127.41	127.41	7.87	20.24		**282.94**
	CO	77.57	77.57	6.59	20.54		**182.27**
	VOC	5.25	5.25	0.77	1.88		**13.15**
	PM	9.28	9.28	1.06	1.88		**21.50**
	PM_{10}	9.28	9.28	1.06	1.88		**21.50**
	$PM_{2.5}$	9.28	9.28	1.06	1.88		**21.50**
	SO_2	0.13	0.13	33.10	0.09		**33.45**
HAPs	Acetaldehyde	0.06	0.06				**0.11**
	Acrolein	0.01	0.01				**0.02**
	Benzene	0.02	0.02	0.005	0.03		**0.07**
	Ethylbenzene	0.04	0.04		0.0005		**0.09**
	Formaldehyde	1.00	1.00	0.01	0.02		**2.02**
	Hexane			0.01	0.31		**0.32**
	Napthalene	0.002	0.002				**0.004**
	PAH	0.003	0.003				**0.006**
	Toluene	0.18	0.18	0.002	0.01		**0.38**
	Xylenes	0.09	0.09	0.002	0.02		**0.20**
	Total HAPs	**1.40**	**1.40**	**0.02**	**0.40**		**3.22**
Non-HAP TACs	Ammonia					1.45	**1.45**
	H_2S			0.96			**0.96**
Greenhouse Gas	CO_2	164,592.34	164,592.34	136,848.28	50,501.40		**516,534.36**
	N_2O	4.22	4.22	0.05	1.90		**10.38**
	CH_4	20.99	20.99	29.24	1.11		**72.33**

	Pollutant	Annual Emissions (ton CO_2e/yr)					
		Turbine A	**Turbine B**	**Thermal Oxidizer**	**Auxiliary Boiler**		**TOTAL**
Greenhouse Gas (CO_2e)	CO_2	164,592.34	164,592.34	136,848.28	50,501.40		**516,534.36**
	N_2O	1,257.10	1,257.10	13.78	565.07		**3,093.05**
	CH_4	524.72	524.72	730.90	27.82		**1,808.17**
	Total GHGs	**166,374.16**	**166,374.16**	**137,592.96**	**51,094.29**		**521,435.58**

Table 3
Emissions for Gas Turbine
Magnolia LNG

Parameter	Units	Average Value	Maximum Value
Fuel Lower Heating Value (LHV)[1]	Btu/scf	935.1	935.1
Fuel Higher Heating Value (HHV) [1]	Btu/scf	1036.4	1036.4
Ratio of HHV to LHV	-	1.108	1.108
Hourly Fuel Flow (LHV)[2]	MMBtu/hr	289.66	312.63
Hourly Fuel Flow (HHV)[3]	MMBtu/hr	321.04	346.50
Annual Operation	hr/yr	8760	-

Pollutant Type	Pollutant	HHV Emission Factor[4] (lb/MMBtu)	Average Hourly Emission Rate[5,6] (lb/hr)	Maximum Hourly Emission Rate[5,6] (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	29.09	31.42	127.41
	CO	-	17.71	19.13	77.57
	VOC	-	1.20	1.29	5.25
	PM	0.0066	2.12	2.29	9.28
	PM_{10}	0.0066	2.12	2.29	9.28
	$PM_{2.5}$	0.0066	2.12	2.29	9.28
	SO_2	0.000094	0.03	0.03	0.13
HAPs	Acetaldehyde	0.000040	0.01	0.01	0.06
	Acrolein	0.0000064	0.002	0.002	0.01
	Benzene	0.000012	0.004	0.004	0.02
	Ethylbenzene	0.000032	0.01	0.01	0.04
	Formaldehyde	0.00071	0.23	0.25	1.00
	Napthalene	0.0000013	0.0004	0.0005	0.002
	PAH	0.0000022	0.0007	0.0008	0.003
	Toluene	0.00013	0.04	0.05	0.18
	Xylene	0.000064	0.02	0.02	0.09
	Total HAPs	**-**	**0.32**	**0.35**	**1.40**
Greenhouse Gas	CO_2	-	37,578.16	40,596.22	164,592.34
	N_2O	0.003	0.96	1.04	4.22
	CH_4	-	4.79	5.12	20.99

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Average Hourly Emission Rate (lb CO_2e/hr)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	37,578	40,596	164,592
	N_2O	298	287	310	1,257
	CH_4	25	120	128	525
	Total GHGs	**-**	**37,985**	**41,034**	**166,374**

Notes:

1. Based on manaufacturer's data.
2. Based on manaufacturer's data.
3. Calculated based on ratio of HHV to LHV.
4. Emissions factors from USEPA AP-42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensible and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensible and filterable fractions). SO_2 emission factor based on sulfur content of <0.0001% by weight (equivalent to <0.00005% molar).
5. NO_x, CO, VOC, CO_2, and CH_4 emissions based on manufacturer's data.
6. PM, PM_{10}, and $PM_{2.5}$, N_2O, and individual HAP emissions based on AP-42 emission factors and maximum fuel flow rate.

Table 4
Emissions for Thermal Oxidizer - Design/Maximum Conditions
Magnolia LNG

Parameter	Amine Plant Exhaust	Combustion Gas	TOTAL
Feed Rate[1,2] (kg/hr)	14,030	443	**14,473**
Feed Rate (lb/hr)	30,931	977	**31,907**
LHV[3] (kcal/kg)	0	11,520	**11,520**
Heat Rate (kcal/hr)	0	5,103,360	**5,103,360**
Heat Rate (MMBtu/hr)	0	20.25	**20.25**
HC Desctruction Efficiency[3]	-	-	**99%**
Hours of Operation (hr/yr)	-	-	**8,760**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)		
		CO_2	Feed Gas	CO_2	Feed Gas	CO_2	Feed Gas	TOTAL
CO_2	44.01	99.9760%	0.0005%	99.9814%	0.0013%	30925.07	0.01	30925.08
Nitrogen	28.01	0.0000%	1.0136%	0.0000%	1.6883%	0.00	16.49	16.49
Methane	16.04	0.0000%	95.5445%	0.0000%	91.1401%	0.00	890.12	890.12
Ethane	30.07	0.0000%	2.5581%	0.0000%	4.5737%	0.00	44.67	44.67
Propane	44.10	0.0000%	0.3243%	0.0000%	0.8503%	0.00	8.30	8.30
i-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	3.08	3.08
n-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	3.08	3.08
i-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	3.40	3.40
n-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	3.40	3.40
n-Hexane	86.18	0.0000%	0.0304%	0.0000%	0.1558%	0.00	1.52	1.52
Benzene	78.11	0.0000%	0.0031%	0.0000%	0.0144%	0.00	0.14	0.14
Cyclohexane	84.16	0.0000%	0.0010%	0.0000%	0.0050%	0.00	0.05	0.05
n-Heptane	100.21	0.0000%	0.0051%	0.0000%	0.0304%	0.00	0.30	0.30
Toluene	92.14	0.0000%	0.0010%	0.0000%	0.0055%	0.00	0.05	0.05
n-Octane	114.23	0.0000%	0.0031%	0.0000%	0.0211%	0.00	0.21	0.21
p-Xylene	106.17	0.0000%	0.0010%	0.0000%	0.0063%	0.00	0.06	0.06
Ethylbenzene	106.17	0.0000%	0.0000%	0.0000%	0.0000%	0.00	0.00	0.00
H_2S	34.08	0.0240%	0.0000%	0.0186%	0.0000%	5.75	0.00	5.75
H_2O	18.02	0.0000%	0.1696%	0.0000%	0.1817%	0.00	1.77	1.77
Total	**-**	**100%**	**100%**	**100%**	**100%**	**30,931**	**977**	**31,907**

Actual Stack Temperature[4]	1500 F	816 C	1089 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow (m^3/hr)	Actual Flow (acfm)
CO_2	719.89	326,535	49.8%	7,315	29,166	17,164
H_2O	142.31	64,550	9.9%	1,446	5,766	3,393
N_2	553.22	250,935	38.3%	5,621	22,413	13,190
O_2	29.32	13,299	2.0%	298	1,188	699
TOTAL	**1,444.74**	**655,320**	**100.0%**	**14,679**	**58,533**	**34,446**

Pollutant Type	Pollutant	Emission Factor[5,6,7] ppmvd @3% O_2	Emission Factor[5,6,7] mg/Nm^3	Emission Factor[5,6,7] lb/MMBtu	Maximum Hourly Emission Rate[8,9] (lb/hr)
Criteria	NO_x	40	74	-	2.40
	CO	-	62	-	2.01
	VOC	-	-	-	0.24
	PM	-	10	-	0.32
	PM_{10}	-	10	-	0.32
	$PM_{2.5}$	-	10	-	0.32
	SO_2	-	-	-	10.08
HAPs	Benzene	-	-	-	0.0014
	Formaldehyde	-	-	0.000081	0.0016
	n-Hexane	-	-	-	0.0021
	Toluene	-	-	-	0.00054
	Xylene	-	-	-	0.00062
	Total HAPs		**-**	**-**	**0.0063**
Non-HAP TACs	H_2S	5	6.9	-	0.22
Greenhouse Gas	CO_2	-	-	-	31,682.36
	N_2O	-	-	0.00070	0.01
	CH_4	-	-	-	8.90

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb/hr)
Greenhouse Gas (CO_2e)	CO_2	1	31,682.36
	N_2O	298	4.20
	CH_4	25	222.53
	Total GHGs	**-**	**31,909.08**

Notes:
1. Combined flow to oxidizer.
2. Engineering estimates
3. Engineering estimates
4. Engineering estimates
5. NOx emission factor (in ppmvd @ 3%O2) based on engineering estimates.
6. CO and PM emission factors and H_2S emission factor (in ppmvd @ 3%O2) based on enginnering estimates.
7. Formaldehyde and N_2O emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
8. Emission rates for VOC, CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.
9. SO_2 emission rate based on conversion of H_2S in total feed rate except for the H_2S assumed to be released to the stack (i.e., 5 ppmvd @ 3%O_2).

Table 5
Emissions for Thermal Oxidizer - Average Conditions
Magnolia LNG

Parameter	Amine Plant Exhaust	Combustion Gas	TOTAL
Feed Rate[1,2] (kg/hr)	10,521	332	**10,853**
Feed Rate (lb/hr)	23,195	732	**23,927**
LHV[3] (kcal/kg)	0	11,520	**11,520**
Heat Rate (kcal/hr)	0	3,826,974	**3,826,974**
Heat Rate (MMBtu/hr)	0	15.19	**15.19**
HC Desctruction Efficiency[4]	-	-	**99%**
Hours of Operation (hr/yr)	-	-	**8,760**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)		
		CO_2	Feed Gas	CO_2	Feed Gas	CO_2	Feed Gas	TOTAL
CO_2	44.01	99.9760%	0.0005%	99.9814%	0.0013%	23190.50	0.01	23190.51
Nitrogen	28.01	0.0000%	1.0136%	0.0000%	1.6883%	0.00	12.36	12.36
Methane	16.04	0.0000%	95.5445%	0.0000%	91.1401%	0.00	667.49	667.49
Ethane	30.07	0.0000%	2.5581%	0.0000%	4.5737%	0.00	33.50	33.50
Propane	44.10	0.0000%	0.3243%	0.0000%	0.8503%	0.00	6.23	6.23
i-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	2.31	2.31
n-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	2.31	2.31
i-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	2.55	2.55
n-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	2.55	2.55
n-Hexane	86.18	0.0000%	0.0304%	0.0000%	0.1558%	0.00	1.14	1.14
Benzene	78.11	0.0000%	0.0031%	0.0000%	0.0144%	0.00	0.11	0.11
Cyclohexane	84.16	0.0000%	0.0010%	0.0000%	0.0050%	0.00	0.04	0.04
n-Heptane	100.21	0.0000%	0.0051%	0.0000%	0.0304%	0.00	0.22	0.22
Toluene	92.14	0.0000%	0.0010%	0.0000%	0.0055%	0.00	0.04	0.04
n-Octane	114.23	0.0000%	0.0031%	0.0000%	0.0211%	0.00	0.15	0.15
p-Xylene	106.17	0.0000%	0.0010%	0.0000%	0.0063%	0.00	0.05	0.05
Ethylbenzene	106.17	0.0000%	0.0000%	0.0000%	0.0000%	0.00	0.00	0.00
H_2S	34.08	0.0240%	0.0000%	0.0186%	0.0000%	4.31	0.00	4.31
H_2O	18.02	0.0000%	0.1696%	0.0000%	0.1817%	0.00	1.33	1.33
Total	**-**	**100%**	**100%**	**100%**	**100%**	**23,195**	**732**	**23,927**

Actual Stack Temperature[4]	1500 F	816 C	1089 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow (m^3/hr)	Actual Flow (acfm)
CO_2	539.84	244,866	49.8%	5,485	21,871	12,871
H_2O	106.72	48,406	9.9%	1,084	4,324	2,544
N_2	414.86	188,174	38.3%	4,215	16,808	9,891
O_2	21.99	9,973	2.0%	223	891	524
TOTAL	**1,083.40**	**491,420**	**100.0%**	**11,008**	**43,893**	**25,831**

Pollutant Type	Pollutant	Emission Factor[5,6,7] ppmvd @3% O_2	Emission Factor[5,6,7] mg/Nm^3	Emission Factor[5,6,7] lb/MMBtu	Average Hourly Emission Rate[8,9] (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	40	74	-	1.80	7.87
	CO	-	62	-	1.50	6.59
	VOC	-	-	-	0.18	0.77
	PM	-	10	-	0.24	1.06
	PM_{10}	-	10	-	0.24	1.06
	$PM_{2.5}$	-	10	-	0.24	1.06
	SO_2	-	-	-	7.56	33.10
HAPs	Benzene	-	-	-	0.0011	0.0046
	Formaldehyde	-	-	0.000081	0.0012	0.0054
	n-Hexane	-	-	-	0.0015	0.0068
	Toluene	-	-	-	0.00040	0.0018
	Xylene	-	-	-	0.00046	0.0020
	Total HAPs		**-**	**-**	**0.0047**	**0.021**
Non-HAP TACs	H_2S	5	6.9	-	0.17	0.96
Greenhouse Gas	CO_2	-	-	-	23,758.38	136,848.28
	N_2O	-	-	0.00070	0.01	0.05
	CH_4	-	-	-	6.67	29.24

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Average Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Greenhouse Gas (CO_2e)	CO_2	1	23,758	136,848
	N_2O	298	3.1	14
	CH_4	25	166.9	731
	Total GHGs	**-**	**23,928.40**	**137,593**

Notes:
1. Combined flow to oxidizer.
2. Engineering estimates
3. Engineering estimates
4. Engineering estimates
5. NOx emission factor (in ppmvd @ 3%O2) based on engineering estimates.
6. CO and PM emission factors and H_2S emission factor (in ppmvd @ 3%O2) based on enginnering estimates.
7. Formaldehyde and N_2O emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
8. Emission rates for VOC, CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.
9. SO_2 emission rate based on conversion of H_2S in total feed rate except for the H_2S assumed to be released to the stack (i.e., 5 ppmvd @ 3%O_2).

Table 6
Emissions for Auxiliary Boiler
Magnolia LNG

Parameter	Average Feed Gas Base Case	Rich Feed Gas Case	Ship Loading Case	High Inerts Feed Gas Case	TOTAL	Units
Combustion Gas Fuel Flow Rate (HHV)	84.74	99.91	94.33	82.87	-	MMBtu/hr
Percentage of Operation	90.00%	3.52%	5.48%	1.00%	-	%
Yearly Operation	7884	308	480	88	8760	hr/yr

Pollutant Type	Pollutant	Emission Rate by Case (lb/hr)				Average Hourly Emission Rate (lb/hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
		Average Feed Gas Base Case	Rich Feed Gas Case	Ship Loading Case	High Inerts Feed Gas Case			
Criteria	NO_x	4.54	4.97	5.66	5.31	4.62	5.66	20.24
	CO	4.60	5.04	5.74	5.39	4.69	5.74	20.54
	VOC	0.42	0.50	0.47	0.4143	0.43	0.50	1.88
	PM	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	PM_{10}	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	$PM_{2.5}$	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	SO_2	0.02	0	0	0.02	0.02	0.02	0.09
HAPs	Benzene	0.007	0.03	0.01	0	0.01	0.03	0.03
	Ethylbenzene	0	0.004	0	0	0.0001	0.004	0.0005
	Formaldehyde	0.004	0.00	0.01	0.003	0.004	0.01	0.02
	n-Hexane	0.072	0.12	0.05	0.0002	0.07	0.12	0.31
	Toluene	0.003	0.01	0.00	0	0.003	0.01	0.01
	Xylene	0.004	0.00	0.00	0	0.003	0.004	0.02
	Total HAPs	**0.09**	**0.16**	**0.07**	**0.003**	**0.09**	**0.16**	**0.40**
Greenhouse Gas	CO_2	11,378.67	13,885.63	12,544.62	11,297.60	11,530.00	13,885.63	50,501.40
	N_2O	0.42	0.80	0.39	0.52	0.43	0.80	1.90
	CH_4	0.25	0.09	0.34	0.43	0.25	0.43	1.11

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Greenhouse Gas (CO_2e)	CO_2	1	13,885.63	50,501.40
	N_2O	298	239.06	565.07
	CH_4	25	10.71	27.82
	Total GHGs	**-**	**14,135.40**	**51,094.29**

Table 7
Auxiliary Boiler - Case 1 - Avg Feed Gas Base Case
Magnolia LNG

Parameter	HCL Vap Rich Gas	N2 Reject	Feed Gas	TOTAL
Boiler Feed Rate[1] (kg/hr)	769	2181	721	**3671**
Boiler Feed Rate (lb/hr)	1695	4808	1590	**8093**
LHV[1] (kcal/kg)	11090	2072	11520	**24682**
Heat Rate (kcal/hr)	8528210	4519032	8305920	**21353162**
Heat Rate (MMBtu/hr)	33.84	17.93	32.96	**84.74**
HC Desctruction Efficiency[2]	-	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)			Weight Fraction (wgt %)			Feed Rate (lb/hr)				Feed Rate (lbmole/hr)
		HCL Vap	N2 Reject	Feed Gas	HCL Vap	N2 Reject	Feed Gas	HCL Vap	N2 Reject	Feed Gas	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.01%	0.00%	0.00%	0.03%	0.00	0.00	0.42	0.42	0.01
Nitrogen	28.01	0.00%	68.14%	1.01%	0.00%	78.88%	1.68%	0.02	3792.68	26.78	3819.48	136.34
Methane	16.04	16.78%	31.86%	95.61%	3.89%	21.12%	91.34%	65.89	1015.60	1451.89	2533.37	157.91
Ethane	30.07	4.65%	0.00%	2.56%	2.02%	0.00%	4.58%	34.22	0.00	72.86	107.09	3.56
Propane	44.10	2.17%	0.00%	0.32%	1.38%	0.00%	0.84%	23.46	0.00	13.36	36.82	0.83
i-Butane	58.12	1.55%	0.00%	0.09%	1.30%	0.00%	0.31%	22.07	0.00	4.95	27.02	0.46
n-Butane	58.12	2.35%	0.00%	0.09%	1.97%	0.00%	0.31%	33.40	0.00	4.95	38.35	0.66
i-Pentane	72.15	6.86%	0.00%	0.08%	7.14%	0.00%	0.34%	121.12	0.00	5.46	126.59	1.75
n-Pentane	72.15	12.60%	0.00%	0.08%	13.13%	0.00%	0.34%	222.56	0.00	5.46	228.02	3.16
n-Hexane	86.18	33.90%	0.00%	0.03%	42.18%	0.00%	0.15%	715.05	0.00	2.45	717.49	8.33
Benzene	78.11	3.70%	0.00%	0.00%	4.17%	0.00%	0.00%	70.78	0.00	0.00	70.78	0.91
Cyclohexane	84.16	1.33%	0.00%	0.00%	1.62%	0.00%	0.00%	27.42	0.00	0.00	27.42	0.33
n-Heptane	100.21	7.17%	0.00%	0.01%	10.38%	0.00%	0.06%	175.91	0.00	0.95	176.86	1.76
Toluene	92.14	1.41%	0.00%	0.00%	1.88%	0.00%	0.00%	31.83	0.00	0.00	31.83	0.35
n-Octane	114.23	4.14%	0.00%	0.00%	6.83%	0.00%	0.00%	115.85	0.00	0.00	115.85	1.01
p-Xylene	106.17	1.38%	0.00%	0.00%	2.11%	0.00%	0.00%	35.77	0.00	0.00	35.77	0.34
Ethylbenzene	106.17	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00
Total	**-**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**1,695**	**4,808**	**1,590**	**8,093**	**317.72**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	32,149	19,027	49,682	29,403

Stack Parameter[3]	Vol %
	(%)
O2	2.30%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)				Stack Concentration			Emission Rate[8] (lb/hr)			
		HCL Vap	N2 Reject	Feed Gas	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	Feed Gas	TOTAL
Criteria	NO_x	-	-	-	-	30	31.18	64.02	-	-	-	**4.54**
	CO	-	-	-	-	50	51.96	64.95	-	-	-	**4.60**
	VOC	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	PM	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	PM_{10}	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	$PM_{2.5}$	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	SO_2	-	-	0.00065	-	-	-	-	-	-	0.02	**0.02**
HAPs	Benzene	-	-	-	-	-	-	-	0.007	0.000	0.000	**0.007**
	Ethylbenzene	-	-	-	-	-	-	-	0.000	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	0.000081	-	-	-	-	-	0.001	0.003	**0.004**
	n-Hexane	-	-	-	-	-	-	-	0.072	0.000	0.000	**0.072**
	Toluene	-	-	-	-	-	-	-	0.003	0.000	0.000	**0.003**
	Xylene	-	-	-	-	-	-	-	0.004	0.000	0.000	**0.004**
	Total HAPs		**-**	**-**	-	-	-	-	**0.085**	**0.001**	**0.003**	**0.090**
Greenhouse Gas	CO_2	140	130	130	-	-	-	-	4,745	2,338	4,296	**11,379**
	N_2O	0.0088	0.0024	0.0024	-	-	-	-	0.30	0.04	0.08	**0.42**
	CH_4	-	-	-	-	-	-	-	0.007	0.10	0.15	**0.25**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject and Feed Gas from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 8
Auxiliary Boiler - Case 2 - Rich Feed Gas Case
Magnolia LNG

Parameter	Vap. HCL	N2 Reject	TOTAL
Boiler Feed Rate[1] (kg/hr)	1990	1500	**3490**
Boiler Feed Rate (lb/hr)	4387	3307	**7694**
LHV[1] (kcal/kg)	11090	2072	**13162**
Heat Rate (kcal/hr)	22069100	3108000	**25177100**
Heat Rate (MMBtu/hr)	87.58	12.33	**99.91**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)			Feed Rate (lbmole/hr)
		HCL Vap	N2 Reject	HCL Vap	N2 Reject	HCL Vap	N2 Reject	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.00%	0.00%	0.01	0.00	0.01	0.00
Nitrogen	28.01	0.00%	68.14%	0.00%	78.88%	0.03	2608.41	2608.44	93.11
Methane	16.04	14.67%	31.86%	3.68%	21.12%	161.46	698.52	859.98	53.60
Ethane	30.07	8.00%	0.00%	3.76%	0.00%	165.16	0.00	165.16	5.49
Propane	44.10	5.74%	0.00%	3.96%	0.00%	173.80	0.00	173.80	3.94
i-Butane	58.12	3.72%	0.00%	3.38%	0.00%	148.32	0.00	148.32	2.55
n-Butane	58.12	5.72%	0.00%	5.20%	0.00%	228.05	0.00	228.05	3.92
i-Pentane	72.15	8.87%	0.00%	10.00%	0.00%	438.90	0.00	438.90	6.08
n-Pentane	72.15	15.43%	0.00%	17.41%	0.00%	763.98	0.00	763.98	10.59
n-Hexane	86.18	19.86%	0.00%	26.77%	0.00%	1174.65	0.00	1174.65	13.63
Benzene	78.11	5.64%	0.00%	6.89%	0.00%	302.19	0.00	302.19	3.87
Cyclohexane	84.16	1.91%	0.00%	2.51%	0.00%	110.18	0.00	110.18	1.31
n-Heptane	100.21	7.28%	0.00%	11.41%	0.00%	500.50	0.00	500.50	4.99
Toluene	92.14	1.46%	0.00%	2.10%	0.00%	92.09	0.00	92.09	1.00
n-Octane	114.23	0.73%	0.00%	1.30%	0.00%	57.10	0.00	57.10	0.50
p-Xylene	106.17	0.49%	0.00%	0.81%	0.00%	35.38	0.00	35.38	0.33
Ethylbenzene	106.17	0.49%	0.00%	0.81%	0.00%	35.38	0.00	35.38	0.33
Total	**-**	**100%**	**100%**	**100%**	**100%**	**4,387**	**3,307**	**7,694**	**205.27**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	34,721	20,549	53,657	31,756

Stack Parameter[3]	Vol % (%)
O2	2.03%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)			Stack Concentration			Emission Rate[8] (lb/hr)		
		HCL Vap	N2 Reject	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	31.63	64.96	-	-	**4.97**
	CO	-	-	-	50	52.72	65.90	-	-	**5.04**
	VOC	-	-	0.005	-	-	-	-	-	**0.50**
	PM	-	-	0.005	-	-	-	-	-	**0.50**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.50**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.50**
	SO_2	-	-	-	-	-	-	-	-	**0.00**
HAPs	Benzene	-	-	-	-	-	-	0.030	0.000	**0.030**
	Ethylbenzene	-	-	-	-	-	-	0.004	0.000	**0.004**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.001	**0.001**
	n-Hexane	-	-	-	-	-	-	0.117	0.000	**0.117**
	Toluene	-	-	-	-	-	-	0.009	0.000	**0.009**
	Xylene	-	-	-	-	-	-	0.004	0.000	**0.004**
	Total HAPs		**-**	-	-	-	-	**0.164**	**0.001**	**0.165**
Greenhouse Gas	CO_2	140	130	-	-	-	-	12,278	1,608	**13,886**
	N_2O	0.0088	0.0024	-	-	-	-	0.77	0.03	**0.80**
	CH_4	-	-	-	-	-	-	0.016	0.07	**0.09**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 9
Auxiliary Boiler - Case 3 - Ship Loading Case
Magnolia LNG

Parameter	Vap. HCL	N2 Reject	TOTAL
Boiler Feed Rate[1] (kg/hr)	574	8400	**8974**
Boiler Feed Rate (lb/hr)	1265	18519	**19784**
LHV[1] (kcal/kg)	11090	2072	**13162**
Heat Rate (kcal/hr)	6365660	17404800	**23770460**
Heat Rate (MMBtu/hr)	25.26	69.07	**94.33**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	(Volume) Fraction[1] (mol %) HCL Vap	N2 Reject	Weight Fraction (wgt %) HCL Vap	N2 Reject	Feed Rate (lb/hr) HCL Vap	N2 Reject	TOTAL	Feed Rate (lbmole/hr) TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Nitrogen	28.01	0.00%	71.98%	0.00%	81.77%	0.01	15142.33	15142.34	540.54
Methane	16.04	16.76%	28.02%	3.88%	18.23%	49.16	3376.48	3425.64	213.53
Ethane	30.07	4.65%	0.00%	2.02%	0.00%	25.58	0.00	25.58	0.85
Propane	44.10	2.18%	0.00%	1.39%	0.00%	17.55	0.00	17.55	0.40
i-Butane	58.12	1.56%	0.00%	1.31%	0.00%	16.55	0.00	16.55	0.28
n-Butane	58.12	2.36%	0.00%	1.98%	0.00%	25.11	0.00	25.11	0.43
i-Pentane	72.15	7.08%	0.00%	7.38%	0.00%	93.38	0.00	93.38	1.29
n-Pentane	72.15	13.18%	0.00%	13.74%	0.00%	173.88	0.00	173.88	2.41
n-Hexane	86.18	32.77%	0.00%	40.80%	0.00%	516.26	0.00	516.26	5.99
Benzene	78.11	3.64%	0.00%	4.11%	0.00%	52.02	0.00	52.02	0.67
Cyclohexane	84.16	1.33%	0.00%	1.62%	0.00%	20.47	0.00	20.47	0.24
n-Heptane	100.21	7.33%	0.00%	10.60%	0.00%	134.18	0.00	134.18	1.34
Toluene	92.14	1.45%	0.00%	1.93%	0.00%	24.40	0.00	24.40	0.26
n-Octane	114.23	4.28%	0.00%	7.06%	0.00%	89.31	0.00	89.31	0.78
p-Xylene	106.17	1.42%	0.00%	2.18%	0.00%	27.60	0.00	27.60	0.26
Ethylbenzene	106.17	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Total	**-**	**100%**	**100%**	**100%**	**100%**	**1,265**	**18,519**	**19,784**	**769.28**

Stack Parameter[3]	Normalized (Nm^3/hr)	(scfm)	Actual (m^3/hr)	(acfm)
Stack Flow	38,633	22,864	59,703	35,334

Stack Parameter[3]	Vol % (%)
O2	1.60%

Pollutant Type	Pollutant	Factor[4,5,6] (lb/MMBtu) HCL Vap	N2 Reject	All	Concentration ppm (3% O2)[7]	ppm	mg/Nm^3	Rate[8] (lb/hr) HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	32.35	66.44	-	-	**5.66**
	CO	-	-	-	50	53.92	67.40	-	-	**5.74**
	VOC	-	-	0.005	-	-	-	-	-	**0.47**
	PM	-	-	0.005	-	-	-	-	-	**0.47**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.47**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.47**
	SO_2	-	-	-	-	-	-	-	-	**0.00**
HAPs	Benzene	-	-	-	-	-	-	0.005	0.000	**0.005**
	Ethylbenzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.006	**0.006**
	n-Hexane	-	-	-	-	-	-	0.052	0.000	**0.052**
	Toluene	-	-	-	-	-	-	0.002	0.000	**0.002**
	Xylene	-	-	-	-	-	-	0.003	0.000	**0.003**
	Total HAPs		**-**	-	-	-	-	**0.062**	**0.006**	**0.068**
Greenhouse Gas	CO_2	140	130	-	-	-	-	3,541	9,003	**12,545**
	N_2O	0.0088	0.0024	-	-	-	-	0.22	0.17	**0.39**
	CH_4	-	-	-	-	-	-	0.005	0.34	**0.34**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 10
Auxiliary Boiler - Case 4 - High Inerts Feed Gas Case
Magnolia LNG

Parameter	N2 Reject	Feed Gas	TOTAL
Boiler Feed Rate[1] (kg/hr)	6120	712	**6832**
Boiler Feed Rate (lb/hr)	13492	1570	**15062**
LHV[1] (kcal/kg)	2072	11520	**13592**
Heat Rate (kcal/hr)	12680640	8202240	**20882880**
Heat Rate (MMBtu/hr)	50.32	32.55	**82.87**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)			Feed Rate (lbmole/hr)
		N2 Reject	Feed Gas	N2 Reject	Feed Gas	N2 Reject	Feed Gas	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.0100%	0.00%	0.03%	0.00	0.41	0.41	0.01
Nitrogen	28.01	68.15%	1.0100%	78.88%	1.68%	10643.18	26.45	10669.63	380.88
Methane	16.04	31.85%	95.6100%	21.12%	91.34%	2849.09	1433.76	4282.85	266.96
Ethane	30.07	0.00%	2.5600%	0.00%	4.58%	0.00	71.95	71.96	2.39
Propane	44.10	0.00%	0.3200%	0.00%	0.84%	0.00	13.19	13.19	0.30
i-Butane	58.12	0.00%	0.0900%	0.00%	0.31%	0.00	4.89	4.89	0.08
n-Butane	58.12	0.00%	0.0900%	0.00%	0.31%	0.00	4.89	4.89	0.08
i-Pentane	72.15	0.00%	0.0800%	0.00%	0.34%	0.00	5.40	5.40	0.07
n-Pentane	72.15	0.00%	0.0800%	0.00%	0.34%	0.00	5.40	5.40	0.07
n-Hexane	86.18	0.00%	0.0300%	0.00%	0.15%	0.00	2.42	2.42	0.03
Benzene	78.11	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Cyclohexane	84.16	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
n-Heptane	100.21	0.00%	0.0100%	0.00%	0.06%	0.00	0.94	0.94	0.01
Toluene	92.14	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
n-Octane	114.23	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
p-Xylene	106.17	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Ethylbenzene	106.17	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Total	**-**	**100%**	**100%**	**100%**	**100%**	**13,492**	**1,570**	**15,062**	**650.89**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	37,118	21,968	57,361	33,948

Stack Parameter[3]	Vol % (%)
O2	2.03%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)			Stack Concentration			Emission Rate[8] (lb/hr)		
		N2 Reject	Feed Gas	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	31.63	64.95	-	-	**5.31**
	CO	-	-	-	50	52.71	65.89	-	-	**5.39**
	VOC	-	-	0.005	-	-	-	-	-	**0.41**
	PM	-	-	0.005	-	-	-	-	-	**0.41**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.41**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.41**
	SO_2	-	0.00065	-	-	-	-	-	0.02	**0.02**
HAPs	Benzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Ethylbenzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.003	**0.003**
	n-Hexane	-	-	-	-	-	-	0.000	0.000	**0.000**
	Toluene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Xylene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Total HAPs		**-**	-	-	-	-	**0.000**	**0.003**	**0.003**
Greenhouse Gas	CO_2	140	130	-	-	-	-	7,055	4,243	**11,298**
	N_2O	0.0088	0.0024	-	-	-	-	0.44	0.08	**0.52**
	CH_4	-	-	-	-	-	-	0.285	0.14	**0.43**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject and Feed Gas from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 11
Emissions for Ammonia Vent
Magnolia LNG

Parameter	Purge
Stack Rate (kg/hr)	130.45
Stack Rate (lb/hr)	287.59
Hours of Operation (hr/yr)	438

Component	Component MW (lb/lbmole)	Weight Fraction (wgt %)	Molar (Volume) Fraction[1] (mol %)	Feed Rate (lb/hr)		Annual Emissions
		Purge	Purge	kg/hr	lb/hr	(tpy)
Ammonia	17.03	2.3%	3.6%	3.00	6.61	1.45
Nitrogen	27.01	96.2%	94.2%	125.49	276.66	60.59
H2O	18.02	1.5%	2.2%	1.96	4.31	0.94
Total	**-**	**100.0%**	**100.0%**	**130.45**	**287.59**	**62.98**

Actual Stack Temperature[4]	68 F	20 C	293 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow	
					(m^3/hr)	(acfm)
Ammonia	0.39	176	3.6%	3.9	4.2	2.5
Nitrogen	10.24	4,646	94.2%	104.1	111.7	65.7
H2O	0.24	109	2.2%	2.4	2.6	1.5
TOTAL	**10.87**	**4,930**	**100.0%**	**110.4**	**119**	**70**

Table 12
Emissions for Warm Flare
Magnolia LNG

Parameter	Units	Pilot Gas	Release	Max
Combustion Gas Fuel Flow Rate[1] (mass)	kg/hr	7.33	60,000	60,007
	lb/hr	16.16	132,276	132,292
Combustion Gas Molecular Weight	g/mol	16.82	16.82	16.82
Combustion Gas Fuel Flow Rate[1] (volume)	Nm^3/hr	9.76	79,923	79,933
	scf/hr	345	2,822,077	2,822,421
Combustion Gas Higher Heating Value[2]	kcal/kg	11,520	11,520	11,520
	J/mol	811,093	811,093	811,093
Combustion Gas Fuel Heat Rate	kcal/hr	84,442	691,200,000	691,284,442
	MMBtu/hr	0.34	2742.68	2,743
Yearly Operation	hr/yr	8760	88	8,760
HC Desctruction Efficiency	%	99.5%	99.5%	99.5%

Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

		Pilot Gas			Release		
Component	Molecular Weight (lb/lbmole)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)
Carbon Dioxide	44.01	0.0005%	0.00%	0.00	0.0005%	0.00%	1.73
Nitrogen	28.01	1.0153%	1.69%	0.27	1.0153%	1.69%	2237.20
Methane	16.04	95.7069%	91.31%	14.75	95.7069%	91.31%	120775.57
Ethane	30.07	2.5625%	4.58%	0.74	2.5625%	4.58%	6061.03
Propane	44.10	0.3249%	0.85%	0.14	0.3249%	0.85%	1126.96
i-Butane	58.12	0.0914%	0.32%	0.05	0.0914%	0.32%	417.88
n-Butane	58.12	0.0914%	0.32%	0.05	0.0914%	0.32%	417.88
i-Pentane	72.15	0.0812%	0.35%	0.06	0.0812%	0.35%	460.84
n-Pentane	72.15	0.0812%	0.35%	0.06	0.0812%	0.35%	460.84
n-Hexane	86.18	0.0305%	0.16%	0.03	0.0305%	0.16%	206.75
Benzene	78.11	0.0031%	0.01%	0.00	0.0031%	0.01%	19.05
Cyclohexane	84.16	0.0010%	0.01%	0.00	0.0010%	0.01%	6.62
n-Heptane	100.21	0.0051%	0.03%	0.00	0.0051%	0.03%	40.20
Toluene	92.14	0.0010%	0.01%	0.00	0.0010%	0.01%	7.25
n-Octane	114.23	0.0031%	0.02%	0.00	0.0031%	0.02%	27.85
p-Xylene	106.17	0.0010%	0.01%	0.00	0.0010%	0.01%	8.35
Ethylbenzene	106.17	0.0000%	0.00%	0.00	0.0000%	0.00%	0.00
Total	**-**	**100%**	**100%**	**16.16**	**100%**	**100%**	**132,276**
Stream Molecular Weight (g/mol)		16.82			16.82		

		Emission Factor[3,4]	Emission Rate (lb/hr)			Annual Emissions (tpy)			PTE (tpy)
Pollutant Type	Pollutant	(lb/MMBtu)	Pilot Gas	Release	MAX	Pilot Gas	Release	TOTAL	TOTAL
Criteria	NO_x	0.068	0.02	186.50	**186.53**	0.10	8.21	**8.31**	**816.98**
	CO	0.37	0.12	1,014.79	**1,014.92**	0.54	44.65	**45.19**	**4,445.33**
	VOC	-	0.002	16.23	**16.23**	0.01	0.71	**0.72**	**71.08**
	PM	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
	PM_{10}	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
	$PM_{2.5}$	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
HAPs	Benzene	-	0.00001	0.10	**0.10**	0.00005	0.004	**0.004**	**0.42**
	Formaldehyde	0.000081	0.00003	0.22	**0.22**	0.0001	0.01	**0.010**	**0.98**
	Hexane	-	0.0001	1.03	**1.03**	0.0006	0.05	**0.05**	**4.53**
	Toluene	-	0.000004	0.04	**0.04**	0.00002	0.002	**0.002**	**0.16**
	Xylene	-	0.00001	0.04	**0.04**	0.00002	0.002	**0.002**	**0.18**
	Total HAPs		**0.00**	**1.43**	**1.43**	**0.0008**	**0.06**	**0.06**	**6.27**
Non-HAP TACs	H_2S								
Greenhouse Gas	CO_2	130	43.56	356,548.61	**356,592.17**	190.79	15,688.14	**15,878.92**	**1,561,873.69**
	N_2O	0.00022	0.00007	0.60	**0.60**	0.0003	0.03	**0.03**	**2.64**
	CH_4	-	0.074	603.88	**603.95**	0.32	26.57	**26.89**	**2,645.31**

		Global Warming Potential	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)	
Pollutant Type	Pollutant	(GWP)	MAX	Actual	PTE
Greenhouse Gas (CO_2e)	CO_2	1	356,592.17	15,878.92	1,561,873.69
	N_2O	298	179.83	8.01	787.66
	CH_4	25	15,098.79	672.34	66,132.70
	Total GHGs	**-**	**371,870.79**	**16,559.28**	**1,628,794.06**

Notes:

1. Engineering estimates.
2. Engineering estimate.
3. NO_x and CO emission factors from United States Environmental Protection Agency (EPA) AP 42 Fifth Edition, Volume I - Section 13.5 - "Industrial Flares".
4. CO_2, formaldehye, and PM emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
5. N_2O emission factors from 40 CFR 98 Table C-2 to Subpart C - Natural Combustion.

Table 13
Emissions for Cold Flare
Magnolia LNG

Parameter	Units	Pilot Gas	Release	Max
Combustion Gas Fuel Flow Rate[1] (mass)	kg/hr	7.33	40,000	40,007
	lb/hr	16.16	88,184	88,200
Combustion Gas Molecular Weight	g/mol	16.82	18.42	18.42
Combustion Gas Fuel Flow Rate[1] (volume)	Nm^3/hr	9.76	48,652	48,662
	scf/hr	345	1,717,898	1,718,243
Combustion Gas Higher Heating Value[2]	kcal/kg	11,520	9,288	9,289
	J/mol	811,093	716,204	716,236
Combustion Gas Fuel Heat Rate	kcal/hr	84,442	371,533,692	371,618,134
	MMBtu/hr	0.34	1474.25	1,475
Yearly Operation	hr/yr	8760	88	8,760
HC Desctruction Efficiency	%	99.5%	99.5%	99.5%

Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

		Pilot Gas			Release		
Component	Molecular Weight (lb/lbmole)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)
Carbon Dioxide	44.01	0.0005%	0.00%	0.00	0.0000%	0.00%	0.00
Nitrogen	28.01	1.0153%	1.69%	0.27	19.8300%	30.16%	26598.80
Methane	16.04	95.7069%	91.31%	14.75	80.1700%	69.84%	61585.20
Ethane	30.07	2.5625%	4.58%	0.74	0.0000%	0.00%	0.00
Propane	44.10	0.3249%	0.85%	0.14	0.0000%	0.00%	0.00
i-Butane	58.12	0.0914%	0.32%	0.05	0.0000%	0.00%	0.00
n-Butane	58.12	0.0914%	0.32%	0.05	0.0000%	0.00%	0.00
i-Pentane	72.15	0.0812%	0.35%	0.06	0.0000%	0.00%	0.00
n-Pentane	72.15	0.0812%	0.35%	0.06	0.0000%	0.00%	0.00
n-Hexane	86.18	0.0305%	0.16%	0.03	0.0000%	0.00%	0.00
Benzene	78.11	0.0031%	0.01%	0.00	0.0000%	0.00%	0.00
Cyclohexane	84.16	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
n-Heptane	100.21	0.0051%	0.03%	0.00	0.0000%	0.00%	0.00
Toluene	92.14	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
n-Octane	114.23	0.0031%	0.02%	0.00	0.0000%	0.00%	0.00
p-Xylene	106.17	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
Ethylbenzene	106.17	0.0000%	0.00%	0.00	0.0000%	0.00%	0.00
Total	**-**	**100%**	**100%**	**16.16**	**100%**	**100%**	**88,184**
Stream Molecular Weight (g/mol)		16.82			18.42		

		Emission Factor[3,4]	Emission Rate (lb/hr)			Annual Emissions (tpy)			PTE (tpy)
Pollutant Type	Pollutant	(lb/MMBtu)	Pilot Gas	Release	MAX	Pilot Gas	Release	TOTAL	TOTAL
Criteria	NO_x	0.068	0.02	100.25	**100.27**	0.10	4.41	**4.51**	**439.19**
	CO	0.37	0.12	545.47	**545.59**	0.54	24.00	**24.54**	**2,389.71**
	VOC	-	0.002	0.12	**0.12**	0.009	0.005	**0.01**	**0.53**
	PM	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
	PM_{10}	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
	$PM_{2.5}$	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
HAPs	Benzene	-	0.00001	0	**0.00001**	0.00005	0	**0.00005**	**0.00005**
	Formaldehyde	0.000081	0.00003	0.12	**0.12**	0.0001	0.01	**0.01**	**0.53**
	Hexane	-	0.0001	0	**0.0001**	0.0006	0	**0.0006**	**0.0006**
	Toluene	-	0.000004	0	**0.000004**	0.00002	0	**0.00002**	**0.00002**
	Xylene	-	0.00001	0	**0.00001**	0.00002	0	**0.00002**	**0.00002**
	Total HAPs		**0.00**	**0.12**	**0.12**	**0.0008**	**0.01**	**0.01**	**0.53**
Non-HAP TACs	H_2S								
Greenhouse Gas	CO_2	130	43.56	191,651.94	**191,695.50**	190.79	8,432.69	**8,623.47**	**839,626.28**
	N_2O	0.00022	0.00007	0.32	**0.32**	0.0003	0.01	**0.01**	**1.42**
	CH_4	-	0.074	307.93	**308.00**	0.32	13.55	**13.87**	**1,349.04**

		Global Warming Potential	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)	
Pollutant Type	Pollutant	(GWP)	MAX	Actual	PTE
Greenhouse Gas (CO_2e)	CO_2	1	191,695.50	8,623.47	839,626.28
	N_2O	298	96.67	4.35	423.43
	CH_4	25	7,699.99	346.80	33,725.98
	Total GHGs	**-**	**199,492.17**	**8,974.62**	**873,775.69**

Notes:

1. Engineering estimates.
2. Engineering estimate.

3. NO_x and CO emission factors from United States Environmental Protection Agency (EPA) AP 42 Fifth Edition, Volume I - Section 13.5 - "Industrial Flares".
4. CO_2, formaldehye, and PM emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
5. N_2O emission factors from 40 CFR 98 Table C-2 to Subpart C - Natural Combustion.

Table 14
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	1000	kW
	1341	hp
Fuel Flow[1]	71.9	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	9.31	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	Emission Factor[2,3] (lb/MMBtu)	Emission Factor[4,5] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	4.8	14.19	3.55
	CO	-	2.6	7.69	1.92
	VOC	-	0.48	1.42	0.35
	PM	-	0.15	0.44	0.11
	PM_{10}	-	0.12	0.36	0.09
	$PM_{2.5}$	-	0.10	0.30	0.08
	SO_2	0.001515	-	0.01	0.004
HAPs	Benzene	0.000776	-	0.01	0.002
	Toluene	0.000281	-	0.003	0.0007
	Total HAPs	**-**	**-**	**0.01**	**0.002**
Greenhouse Gas	CO_2	165	-	1,536.18	384.05
	N_2O	0.00132		0.01	0.003
	CH_4	0.0081	-	0.08	0.02

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	1,536.18	384.05
	N_2O	298	3.67	0.92
	CH_4	25	1.89	0.47
	Total GHGs	**-**	**1,541.74**	**385.43**

Notes:

1. Based on representative engine.

2. Emission factors (except for N_2O) from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. October 1996. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

3. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

4. NO_x, CO, VOC, and PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

5. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-feul Engines. October 1996.

Table 15
Emissions for Emergency Fire Pump
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	250	kW
	355	hp
Fuel Flow[1]	18.6	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	2.41	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	Emission Factor[2,3,4] (lb/MMBtu)	Emission Factor[5,6] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	3.0	2.35	0.59
	CO	-	2.6	2.03	0.51
	VOC	-	0.3	0.23	0.06
	PM	-	0.15	0.12	0.03
	PM_{10}	-	0.12	0.10	0.02
	$PM_{2.5}$	-	0.10	0.08	0.02
	SO_2	0.001515	-	0.004	0.0009
HAPs	Benzene	0.000933	-	0.002	0.0006
	Formaldehyde	0.00118	-	0.0028	0.0007
	Total HAPs	**-**	**-**	**0.005**	**0.001**
Greenhouse Gas	CO_2	164	-	394.99	98.75
	N_2O	0.00132		0.003	0.001
	CH_4	0.0081	-	0.02	0.00

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	394.99	98.75
	N_2O	298	0.95	0.24
	CH_4	25	0.49	0.12
	Total GHGs	**-**	**396.43**	**99.11**

Notes:

1. Based on representative engine.

2. Individual HAP and CO_2 emission factors from USEPA AP 42 Section 3.3 - Gasoline and Diesel Industrial Engines.

3. SO_2 and CH_4 emission factors from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

4. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

5. NO_x, CO, and VOC emission factors based on Non-Road Tier 3 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

6. PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines.

Table 16
Emissions for Deluge Pump
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	600	kW
	801	hp
Fuel Flow[1]	37.9	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	4.91	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[2,3] (lb/MMBtu)	Emission Factor[4,5] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	4.8	8.48	2.12
	CO	-	2.6	4.59	1.15
	VOC	-	0.48	0.85	0.21
	PM	-	0.15	0.26	0.07
	PM_{10}	-	0.12	0.22	0.05
	$PM_{2.5}$	-	0.10	0.18	0.05
	SO_2	0.001515	-	0.007	0.002
HAPs	Benzene	0.000776	-	0.004	0.001
	Total HAPs	**-**	**-**	**0.004**	**0.001**
Greenhouse Gas	CO_2	164	-	804.85	201.21
	N_2O	0.00132		0.01	0.002
	CH_4	0.0081	-	0.04	0.01

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	804.85	201.21
	N_2O	298	1.93	0.48
	CH_4	25	0.99	0.25
	Total GHGs	**-**	**807.77**	**201.94**

Notes:

1. Based on representative engine.

2. Emission factors from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. October 1996. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

3. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

4. NO_x, CO, VOC, and PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

5. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-feul Engines. October 1996.

Table 19 - LNG Vessel and Tug Boat Operational Emissions

SLOW SPEED DIESEL without reliquefaction

		Nat Gas	Units	Tugs Diesel	Units	Oil	Units
Emission	NOx	1.3	g/kW-hr	13.2	g/kW-hr	13.6	g/kW-hr
Factors	CO	1.1	g/kW-hr	1.1	g/kW-hr	1.4	g/kW-hr
	VOC	0.5	g/kW-hr	0.5	g/kW-hr	0.6	g/kW-hr
	PM10	0.05	g/kW-hr	0.72	g/kW-hr	0.19	g/kW-hr
	PM2.5	0.05	g/kW-hr	0.72	g/kW-hr	0.17	g/kW-hr
	(Tug factor based on ULSD marine diesel) SO2	0.05	g/kW-hr	0.0065	g/kW-hr	0.36	g/kW-hr
	CO2	420	g/kW-hr	690	g/kW-hr	588.79	g/kW-hr
	N2O			0.02	g/kW-hr	0.031	g/kW-hr
	CH4			0.09	g/kW-hr	0.006	g/kW-hr

Assumptions

LNG Carrier speed at rated power = 19 knots

LNG Vessel oil Efs from Table 2-9 ICF Report for slow speed diesel, marine gas oil 0.1% sulfur. Nat Gas factors from Wartsila for 50DF and American Shipping Bureau

95% Nat Gas/5% MGO used on inbound and outbound trip in propulsion engines - revised based on info from MAN diesel regarding ME-GI propulsion

99% Nat Gas/1% MGO used in generator set engine for Hoteling

Tug boat emission factor based on Cat 2 Engine, Tier 0, Table 3-8 ICF Report. SO2 factor corrected to 500 ppm fuel S.

0.8 Per Table 2-12 ICF Report, NOx adjustment factor for oil use in ECA for 2015 for main engines

0.1 Estimated effect of Nonroad fuel requirement on sulfur content after June 1, 2007 (90% reduction).

While hoteling, assume aux engine uses on MGO, propulsion engines shutdown.

Annual Carrier dockings (175K m3 vessel)	104 berthings/yr	berthings based on 2/week as stated in RR1
Annual Barge dockings (15K m3 barge)	104 berthings/yr	berthings based on 2/week as stated in RR1

Total Power LNG Carrier	30,575 bhp	22,800 kW	LNG power based on typical 175K m3 DFDE LNG carrier
Total Power (2 assist Tugs)	12,000 bhp	8,948 kW	
Total Power (1 assist Tug)	6,000 bhp	4,474 kW	

LNG Carrier and Assist Tugs

Vessel	Activity	Duration (hr)	Engine Use (%)	Total Engine Rating (bhp)	Total Engine Rating (kW)	Natural Gas Flow (MMBtu/hr)	Activity Emissions (lb) NOx	CO	VOC	PM10	PM2.5	SO2	CH4	N2O	CO2	Annual Emissions (tpy) NOx	CO	VOC	PM10	PM2.5	SO2	CH4	N2O	CO2
LNG Carrier	10.4 n. miles out to shore @ 12 knots	0.9	80%	24460	18240	178.6	69	40	18	2	2	2	0	0	15505	3.6	2.1	1.0	0.1	0.1	0.1	0.0	0.0	806
Inbound	Shore up Calcasieu to Devil's Elbow 19 n. miles @ avg 6 knots	3.2	50%	15288	11400	111.6	154	90	41	5	5	5	0	0	34457	8.0	4.7	2.1	0.2	0.2	0.3	0.0	0.0	1792
95%Natural Gas	Maneuvering from Devil's Elbow to berth 3 n. mi. @ 3 kts including turn around	2.0	25%	7644	5700	55.8	48	28	13	1	1	2	0	0	10768	2.5	1.5	0.7	0.1	0.1	0.1	0.0	0.0	560
5% marine gas oil	**Subtotal**	**6.1**	-	-	-	-	**271**	**158**	**72**	**8**	**8**	**9**	**0**	**0**	**60730**	**14.1**	**8.2**	**3.7**	**0.4**	**0.4**	**0.5**	**0.0**	**0.0**	**3158**
	Hoteling while loading	**18.0**	10%	3057.5	2280	n/a	1230	127	54	17	15	33	1	1	53271	64.0	6.6	2.8	0.9	0.8	1.7	0.0	0.0	2770
LNG Carrier	Maneuvering away from dock (straight out) to Devil's Elbow 3 n. mi. @ 3 kts	1.0	25%	7643.75	5700	55.8	24	14	6	1	1	1	0	0	5384	1.3	0.7	0.3	0.0	0.0	0.0	0.0	0.0	280
Outbound	Transit from Devil's Elbow to Gulf shore line 19 n.mi. @avg 6 kts	3.2	50%	15287.5	11400	111.6	154	90	41	5	5	5	0	0	34457	8.0	4.7	2.1	0.2	0.2	0.3	0.0	0.0	1792
95%Natural Gas	Shore to 10.4 n. miles out @ 12 knots	0.9	80%	24460	18240	178.6	69	40	18	2	2	2	0	0	15505	3.6	2.1	1.0	0.1	0.1	0.1	0.0	0.0	806
5% marine gas oil	**Subtotal**	**5.1**					**247**	**144**	**65**	**7**	**7**	**8**	**0**	**0**	**55346**	**12.9**	**7.5**	**3.4**	**0.4**	**0.4**	**0.4**	**0.0**	**0.0**	**2878**
	2 tugs transit from port to meet Carrier offshore (32 n. miles @ 10 kts)	3.2	80%	9600	7159	n/a	667	56	25	36	36	0	5	1	34847	34.7	2.9	1.3	1.9	1.9	0.0	0.2	0.1	1812
Tug Boats	2 tugs transit alongside Carrier to Port (32.4 n. Miles) @ avg 8 kts.	4.1	70%	8400	6264	n/a	747	62	28	41	41	0.4	5.1	1.1	39067	38.9	3.2	1.5	2.1	2.1	0.0	0.3	0.1	2031
	2 addnl tugs transit out to meet Carrier at 3.04 n. mi. from Magnolia @ 10 kts.	0.3	80%	9600	7159	n/a	62	5	2	3	3	0.0	0.4	0.1	3267	3.2	0.3	0.1	0.2	0.2	0.0	0.0	0.0	170
	4 tugs transit alongside Carrier for 3.04 n. mi. to Magnolia @ 3.5 kts.	0.9	50%	12000	8948	n/a	227	19	9	12	12	0.1	1.5	0.3	11843	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	616
Diesel	4 tugs assist carrier dock at Magnolia	1.0	90%	21600	16107	n/a	469	39	18	26	26	0.2	3.2	0.7	24502	24.4	2.0	0.9	1.3	1.3	0.0	0.2	0.0	1274
	1 tug standby during loading	17.5	10%	600	447	n/a	228	19	9	12	12	0.1	1.6	0.3	11911	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	619
	4 tugs full power push/tow away from dock	1.0	90%	21600	16107	n/a	469	39	18	26	26	0.2	3.2	0.7	24502	24.4	2.0	0.9	1.3	1.3	0.0	0.2	0.0	1274
	4 tugs transit alongside Carrier to 3.04 n. mi. to Magnolia @ 3.5 kts.	0.9	50%	12000	8948	n/a	227	19	9	12	12	0.1	1.5	0.3	11843	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	616
	2 addnl tugs transit to port from Carrier at 3.04 n. mi. from Magnolia @ 10 kts.	0.3	80%	9600	7159	n/a	62	5	2	3	3	0.0	0.4	0.1	3267	3.2	0.3	0.1	0.2	0.2	0.0	0.0	0.0	170
	2 tugs transit alongside Carrier to release offshore (32 n. Miles)	4.1	70%	8400	6264	n/a	747	62	28	41	41	0.4	5.1	1.1	39067	38.9	3.2	1.5	2.1	2.1	0.0	0.3	0.1	2031
	2 tugs transit from release of Carrier to port	3.2	80%	9600	7159	n/a	667	56	25	36	36	0.3	5	1	34847	34.7	2.9	1.3	1.9	1.9	0.0	0.2	0.1	1812
	Subtotal	**36.4**					**4571.4**	**381.0**	**173.2**	**249**	**249**	**2.3**	**31.2**	**6.9**	**238960**	**237.7**	**19.8**	**9.0**	**13.0**	**13.0**	**0.0**	**1.6**	**0.4**	**12426**
Barge Loading	Tug boat maneuvering barge to dock	**1.0**	90%	5400	4026.78	n/a	117	10	4	6	6	0	0.8	0.2	6125	6.1	0.5	0.2	0.3	0.3	0.0	0.0	0.0	319
One Tug Boat	Tug boat standby while barge loaded	**2.0**	10%	600	447.42	n/a	26	2	1	1	1	0	0.2	0.0	1361	1.4	0.1	0.1	0.1	0.1	0.0	0.0	0.0	71
	Tug boat maneuvering barge away from dock	**1.0**	90%	5400	4026.78	n/a	117	10	4	6	6	0	0.8	0.2	6125	6.1	0.5	0.2	0.3	0.3	0.0	0.0	0.0	319
	Subtotal						**260**	**22**	**10**	**14**	**14**	**0**	**2**	**0**	**13612**	**13.5**	**1.1**	**0.5**	**0.7**	**0.7**	**0.0**	**0.1**	**0.0**	**708**
TOTAL							**6581**	**831**	**374**	**296**	**294**	**53**	**34**	**8**	**421919**	**342.2**	**43.2**	**19.5**	**15.4**	**15.3**	**2.6**	**1.7**	**0.4**	**21940**

Table 20 - Operational Mobile Sources - Magnolia LNG

Source	Emission Factors												
	NOx	CO	VOC	PM	PM10	PM2.5	SO2	CO2	CO2e	CH4	N2O	Units	Emission Factor Source
Worker Commutes	0.089	1.177	0.015	0.011	0.011	0.005	0.004	n/a	172	n/a	n/a	g/mile	USEPA MOVES model run for Calcasieu Parish
Tug/barge LNG Distribution	13.200	1.100	0.500	0.720	0.720	0.720	0.007	690	n/a	0.09	0.02	g/kw-hr	7000 hp (5220 kW) tug, EF from ICF USEPA Ports Emission Factor report
Truck Distribution	2.376	0.597	0.100	0.122	0.122	0.097	0.011	n/a	1045	n/a	n/a	g/mile	USEPA MOVES model run for Calcasieu Parish

Source	Activity Data per RT	Activity units	Number of Trips	Frequency	Frequency Units	Activity per time unit	Activity per year	Hours per year	Number of Trips Data Source
Worker Commutes	40	miles	40	1	day	1600	584000	n/a	Magnolia Traffic Study, October 2013, page 22.
Tug/barge LNG Distribution	15	hours	2	1	week	n/a	n/a	1560	RR1: up to 2 tug/barges per week. Assume maximum RT distance 45 n. miles @3 knots maximum
Truck Distribution	38	miles	1	1	week	38	1976	n/a	RR1: current potential is one truck trip per week. Miles from site to I-10 per traffic study likely route.

Source	Emissions (tons)										
	NOx	CO	VOC	PM	PM10	PM2.5	SO2	CO2	CO2e	CH4	N2O
Worker Commutes	0.057	0.758	0.010	0.007	0.007	0.003	0.003	n/a	110	n/a	n/a
Tug/barge LNG Distribution	52.49	4.37	1.99	2.86	2.86	2.86	0.03	2744	2776	0.358	0.080
Truck Distribution	0.005	0.001	0.000	0.000	0.000	0.000	0.000	n/a	2	n/a	n/a
Total	**52.6**	**5.1**	**2.0**	**2.9**	**2.9**	**2.9**	**0.0**	**2743.7**	**2889.1**	**0.4**	**0.1**

Appendix 9.B.2

Fugitive Emissions Calculations

[PRIVILEGED]

This page left blank intentionally.

Appendix 9.C
Air Modeling Protocols and Associated Correspondence

This page left blank intentionally.

Appendix 9.C.1

Air Quality Modeling Protocol

This page left blank intentionally.

Magnolia LNG LLC
1001 McKinney St. Suite 400
Houston, TX 77002
713-815-6900
www.magnolialng.com

January 16, 2014

Via Email and UPS

Tegan Treadaway
Louisiana Department of Environmental Quality
Air Quality Supervisor
P.O. Box 4313
Baton Rouge, LA 70821-4313

Re: Magnolia LNG Air Quality Modeling Protocol

Dear Tegan,

Magnolia LNG, LLC (Magnolia) is pleased to submit the enclosed Air Quality Modeling Protocol for LDEQ's review. Magnolia has prepared the protocol to describe the methods, pre and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's impact compared to significant impact levels (SILs), the significant monitoring concentration (SMC) and, for impacts above applicable SILs, to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels.

We appreciate LDEQ's review of our modeling protocol. Should you have any questions or require any additional information, please do not hesitate to contact myself at 713-815-6930 or khassan@magnolialng.com; Bruce Wattle at 716-684-8060 ext. 2572 or bwattle@ene.com; or Bill Daughdrill at 850-435-8925 ext. 4303 or wdaughdrill@ene.com.

Thank you,

Komi O. Hassan

Komi Hassan
EH&S Manager
Magnolia LNG

Enclosure:

cc: Bryan Johnston, Yvette Olmos

This page left blank intentionally.

MAGNOLIA LNG PROJECT

Air Quality Modeling Protocol

15 January 2014

Submitted to:

Louisiana Department of Environmental Quality

Submitted by:

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

This page left blank intentionally.

TABLE OF CONTENTS

Section Page

Tables iv
Figures iv
Appendix iv
Acronyms and Abbreviations v

1 INTRODUCTION 1
1.1 OBJECTIVE 1
1.2 PROJECT DESCRIPTION 1
1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT 1
1.4 SOURCE DESIGNATION 5

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE 6
2.1 NEW SOURCE REVIEW 6
2.2 SHORT-TERM NAAQS MODELING GUIDANCE 6

3 MODELING METHODOLOGY 7
3.1 CLASS II MODELING GUIDANCE 7
3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS 7
3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS 10
3.4 MODEL SELECTION 11
3.5 SOURCE CHARACTERIZATION 11
3.6 EFFECTS OF NEARBY FACILITIES 13
3.7 TOXIC AIR POLLUTANT ANALYSIS 14

4 AERMOD MODELING OPTIONS 15
4.1 BUILDING DOWNWASH 15
4.2 TERRAIN 15
4.3 METEOROLOGICAL DATA 15
4.4 RECEPTORS 16
4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS 17

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS 19
5.1 CLASS I 19
5.2 ADDITIONAL IMPACT ANALYSIS 19

Section Page

6 REPORTING OF RESULTS 20

7 REFERENCES 21

TABLES

Page

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project 5

Table 2 State and National Ambient Air Quality Standards 7

Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project 9

Table 4 Ambient Air Monitoring Stations near Lake Charles 10

Table 5 Emission Source Equipment Inventory – Magnolia LNG Project.....12

Table 6 Preliminary Stack Parameter Values for Project Emission Sources 12

FIGURES

Page

Figure 1 General Location Map of the Magnolia LNG Project 2

Figure 2 Project Site Boundary Map 3

Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations 4

APPENDIX

A Preliminary Operational Emission Estimates

ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program with Prime
BTEX	benzene, toluene, ethylbenzene, and xylene
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DEM	digital elevation models
DLE	dry-low emissions
GHG	greenhouse gas
KMLP	Kinder Morgan Louisiana Pipeline
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
LNG	liquefied natural gas
m^3	cubic meter(s)
Magnolia	Magnolia LNG, LLC
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NO_X	nitrogen oxide
NOAA	National Oceanic and Atmospheric Administration
NSR	New Source Review
OSMR®	Optimized Single Mixed Refrigerant
PM_{10}	particulate matter equal to or less than 10 micrometers aerodynamic diameter
$PM_{2.5}$	particulate matter equal to or less than 2.5 micrometers aerodynamic diameter
Port	Lake Charles Harbor & Terminal District

Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
PVMRM	plume volume molar ratio method
SIL	significant impact level
SMC	significant monitoring concentration
TAP	toxic air pollutant
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds

1 INTRODUCTION

1.1 OBJECTIVE

Magnolia LNG, LLC (Magnolia) has prepared this protocol to describe the methods, pre- and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's impact compared to significant impact levels (SILs), the significant monitoring concentration (SMC) and, for impacts above applicable SILs, to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels. The protocol is based on the current United States Environmental Protection Agency's (USEPA's) Guideline on Air Quality Models (USEPA 2005), the USEPA's New Source Review Workshop Manual (1990), various recent USEPA memoranda regarding modeling procedures for short term standards analysis, and the Louisiana Department of Environmental Quality's (LDEQ's) Air Quality Modeling Procedures (the latter as updated by discussions with LDEQ) (LDEQ 2006).

1.2 PROJECT DESCRIPTION

Magnolia is proposing to develop a natural gas liquefaction facility in Lake Charles, Calcasieu Parish, Louisiana, on a currently vacant site. Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants.

The Magnolia LNG Project (referred to herein as the Project) facility would be capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of liquefied natural gas (LNG). Magnolia would use its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology to produce LNG. The Project would receive natural gas via an existing pipeline that passes beneath the Project site near the southern boundary. Associated with the Project, Kinder Morgan Louisiana Pipeline (KMLP) would develop a compressor station in Eunice Louisiana, approximately 52 miles from the Project site. Permitting and any modeling required for the KMLP Eunice compressor station would be undertaken directly by KMLP.

The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles,

available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1 is a general location map of the Project.

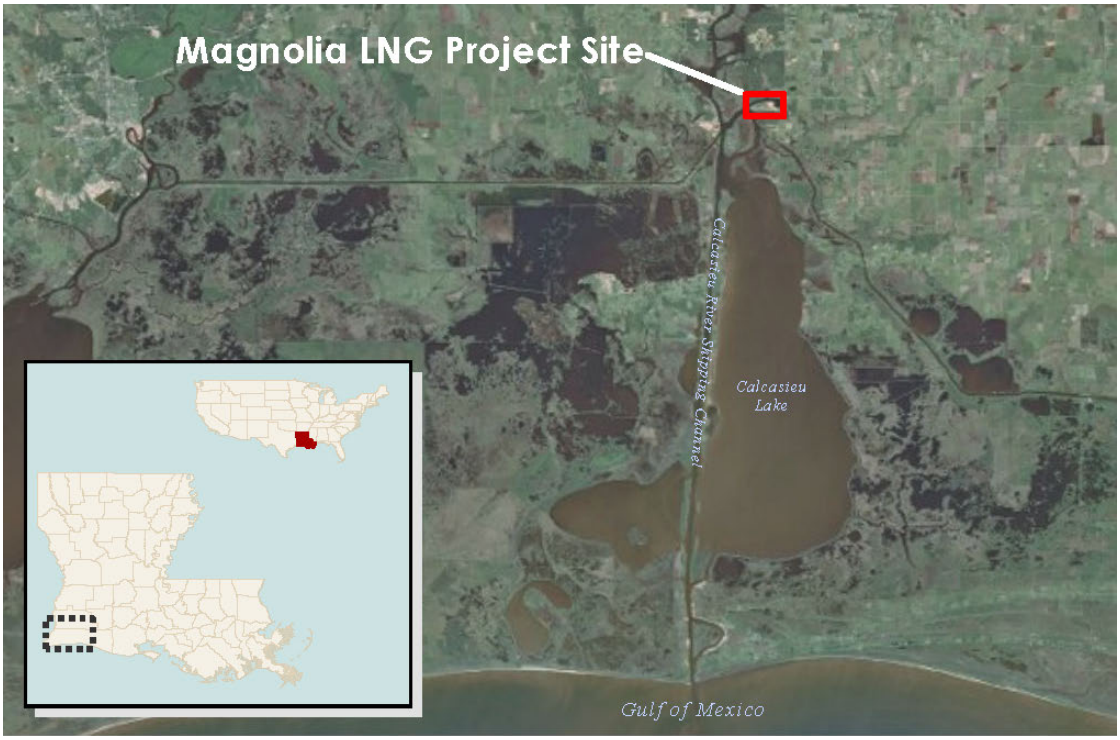


Figure 1 General Location Map of the Magnolia LNG Project

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement (Option Agreement) with the Port for the Project site. The Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each, for a total of 70 years. The expected operational life of the Project is a minimum of 30 years. Figure 2 shows the boundary of the lease area.

Magnolia has prepared a preliminary layout of equipment on the leased area. Figure 3 shows the location of the emission sources to be modeled for the Project analysis and air permit application.

Figure 2 Project Site Boundary Map

Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations

1.4 SOURCE DESIGNATION

Initial potential to emit (PTE) estimates and Project location in an attainment area for all criteria pollutants indicate that a PSD modeling analysis will be required for the criteria pollutants nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter equal to or less than 10 micrometers aerodynamic diameter (PM_{10}), and particulate matter equal to or less than 2.5 micrometers aerodynamic diameter ($PM_{2.5}$). Emissions of greenhouse gas (GHG) also would be above PSD major source thresholds; however, GHGs are not currently subject to modeling requirements. Initial PTE for the Project is shown in Table 1. Emission calculation details are provided in Appendix A of this protocol.

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs	CO_2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator	1.5	3.0	0.0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump	0.7	1.5	0.0	0.01	0.01	0.4	0.06	125
Flares	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Project Total	**1,119**	**813**	**33**	**90**	**90**	**57**	**16**	**1,559,837**
PSD Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**N/A**	**100,000**
Trigger PSD?	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	**N/A**	**YES**
Significant Emission Rate	**40**	**100**	**40**	**15**	**10**	**40**	**N/A**	**N/A**
PSD Modeling Required?	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**N/A**	**N/A**

Key:
CO = carbon monoxide.
CO_2e = carbon dioxide equivalent.
HAPs = hazardous air pollutants.
N/A = Not applicable.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
PSD = Prevention of Significant Deterioration.
SO_2 = sulfur dioxide.
TBD = To be determined.
VOC = volatile organic compound.

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE

2.1 NEW SOURCE REVIEW

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the Clean Air Act. NSR must be addressed before construction can begin on new major sources or major modifications to existing major sources. The PSD program is the NSR permitting program for sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Emission source thresholds for nonattainment areas are lower than the emission source thresholds for attainment areas. The Project location is unclassifiable/ attainment and, therefore, is compared to attainment area major source NSR thresholds.

The major source attainment area NSR thresholds are either 100 tons per year (tpy) or 250 tpy. The 100 tpy threshold applies only to 28 distinct source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 source categories; therefore, the applicable major source threshold is 250 tpy per criteria pollutant and 100,000 tpy for carbon dioxide equivalent (CO_2e). Estimated operational emissions would be above 250 tpy for nitrogen oxide (NO_X) and CO and above 100,000 tpy for CO_2e (see Table 1); therefore, the Project is subject to major source NSR attainment area (PSD) permitting.

2.2 SHORT-TERM NAAQS MODELING GUIDANCE

The USEPA has provided guidance for modeling methodology for the 1-hour NO_2 NAAQS in a series of memoranda (USEPA 2010a, 2011). The guidance provided in these memoranda describe procedures for processing and interpreting model results with regards to the statistical form of the 1-hour NO_2 NAAQS. The USEPA has also provided guidance for modeling to demonstrate compliance with the $PM_{2.5}$ NAAQS (USEPA 2010b). Magnolia will follow these procedures when modeling and processing model results.

3 MODELING METHODOLOGY

3.1 CLASS II MODELING GUIDANCE

The approach for the air quality modeling analysis is based on the USEPA's Guideline on Air Quality Models, incorporated as 40 CFR 51, Appendix W (USEPA 2005). Additional guidance documents to be used include the following:

- The LDEQ's Air Quality Modeling Procedures (LDEQ 2006), incorporating changes as discussed with the LDEQ.
- The USEPA memorandum on the guidance concerning the implementation of the 1-hour NO_2 NAAQS for the PSD program (USEPA 2010a).
- The USEPA memorandum on "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" (USEPA 2010b).
- The USEPA memorandum on "Draft Guidance for $PM_{2.5}$ Permit Modeling" (USEPA 2013a).
- The USEPA document regarding the "Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration – Questions and Answers" (USEPA 2013b).

3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS

NAAQS and/or Louisiana ambient air quality standards have been promulgated for the following criteria pollutants: CO, lead, NO_2, ozone, PM_{10}, $PM_{2.5}$, and SO_2. NAAQS and Louisiana ambient air quality standards are summarized in Table 2.

Table 3 summarizes PSD class I and II increments, SILs, and monitoring de minimis concentrations.

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
CO	8-hour	10,000	9[(a)]	-		Same as Primary NAAQS
	1-hour	40,000	35[(a)]	-		Same as Primary NAAQS
Lead	Rolling 3-month average	0.15	-	Same as Primary NAAQS		Same as Primary NAAQS

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
NO_2	Annual	100	0.053	Same as Primary NAAQS		Same as Primary NAAQS
	1-hour	188	0.100	-		-
Ozone	8-hour	147	0.075[b]	Same as Primary NAAQS		Same as Primary NAAQS
PM_{10}	24-hour	150[c]	-	Same as Primary NAAQS		Same as Primary NAAQS
$PM_{2.5}$	Annual	12.0[d]	-	15.0	-	Same as Secondary NAAQS
	24-hour	35[e]	-	Same as Primary NAAQS		Same as Primary NAAQS
SO_2	Annual	80[f]	-	-	-	Same as Primary NAAQS
	24-hour	365[f]	-	-	-	Same as Primary NAAQS
	3-hour	-	-	1,300	0.5	Same as Secondary NAAQS
	1-hour	195	0.075	-	-	Same as Primary NAAQS

Notes:

(a) Not to be exceeded more than once per year.

(b) The 2008 standard. The three-year average of the 4th highest daily maximum 8-hour average concentration over each year must not exceed the standard.

(c) Not to be exceeded more than once per year on average over three years.

(d) The three-year average of the weighted annual mean concentrations must not exceed the standard.

(e) The three-year average of the 98th percentile concentrations must not exceed the standard.

(f) The USEPA revoked the annual and 24-hour standards in the 2010 SO_2 rulemaking establishing the 1-hour standard and retaining the 3-hour secondary standard. However, the annual and 24-hour standards remain in effect until one year after an area is designated for the 2010 standard. The USEPA issued designations on July 25, 2013; therefore, the annual and 24-hour standards remain in effect until July 25, 2014.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project

Pollutant	Averaging Period	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	PSD SERs (tpy)	SILs ($\mu g/m^3$)	Monitoring De Minimis Concentrations ($\mu g/m^3$)
PM_{10}	24-hour	8[a]	30[a]	15[a]	5	10
$PM_{2.5}$	Annual	1	4	10 of $PM_{2.5}$	0.3	
				40 of SO_2	N/A	
				40 of NO_X[b]	N/A	
	24-hour	2	9		1.2	0[c]
NO_2	Annual	2.5	25	40 of NO_X	1	14
	1-hour	-[c]	-[c]		7.5[c]	
Ozone	8-hour	-	-	40 of VOC or NO_X	-	VOC or NO_X emissions increase > 100 tpy
CO	8-hour	-	-	100	500	575
	1-hour	-	-		2,000	-

Notes:

(a) In addition to PM_{10}, there is a PSD SER for Total Suspended Particulate (TSP) of 25 tpy.

(b) NO_X emissions regulated unless demonstrated not to be a $PM_{2.5}$ precursor. Ammonia and VOC emissions are presumed not to be precursors. See 73 *Federal Register* 28321 for additional details.

(c) PSD Increments, SIL, and Monitoring De Minimum Concentration level for the 1-hour NO_2 standard has not been finalized. However, an interim SIL of 7.5 µg/m3 for NO_2 was provided by the USEPA in a general guidance implementation memo dated June 28, 2010. The monitoring de minimis concentration for $PM_{2.5}$ was effectively set equal to zero due to the Circuit Court decision on January 22, 2013.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

NO_2 = nitrogen dioxide

NO_X = nitrogen oxide

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

USEPA = United States Environmental Protection Agency

VOC = volatile organic compounds.

3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS

For primary air pollutant compounds, i.e., pollutants directly emitted from emission sources, and secondary air pollutants (ozone, formed from the directly emitted pollutants NO_X and VOC), four monitoring stations surround Lake Charles. These are detailed in Table 4 along with the pollutants monitored at each site.

Table 4 Ambient Air Monitoring Stations near Lake Charles

Site	Distance and Direction from Project Site	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC	Ozone
Baton Rouge	130 miles to east	✓	✓	✓	✓	✓		✓
Lafayette	75 miles to east			✓	✓			✓
Carlyss	4.8 miles to northwest							✓
Lake Charles Lighthouse Lane	7.6 miles to north-northwest						✓	
Westlake	11 miles to north		✓		✓	✓	✓	✓
McNeese University	7 miles to northeast				✓			

Source: LDEQ n.d.
Key:
CO = carbon dioxide.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
SO_2 = sulfur dioxide.
VOC = volatile organic compounds.

Magnolia evaluated the distance, direction, and surroundings of each monitoring site to select the appropriate background monitor data sites. Magnolia proposes to use the Westlake monitor site for background data for NO_X, SO_2, and ozone since it is the closest monitoring site to the Project location where these pollutants are measured and is representative of the Project location. Magnolia proposes to use $PM_{2.5}$ data from the McNeese University site, which is the closest $PM_{2.5}$ monitoring station to the Project location. There are no stations in the Lake Charles vicinity that monitor for CO or PM_{10}; the closest site where PM_{10} is monitored is in Lafayette (approximately 75 miles to the east), and CO is monitored in Baton Rouge (approximately 130 miles to the east). These latter two sites are proposed as PM_{10} and CO background data sites. While relatively distant from the Project location and surrounded by urbanized land development, they likely represent typical PM_{10} and CO concentrations for an urban/developed land type setting similar to the Project location. Due to the central city location of the Baton Rouge CO monitor, a higher influence of vehicle emissions may tend to cause data from this station to be slightly conservative (higher) than the Project site. The appropriate statistical form

of the background concentration data will be obtained from either the LDEQ or the USEPA Airs database. Adjusted background procedures as described in the LDEQ guidance will not be used.

3.4 MODEL SELECTION

The USEPA's AERMOD, Version 13350 (issued December 16, 2013), will be the regulatory dispersion model used to estimate ambient impact concentrations of emissions from the Project sources. Regulatory default options as recommended in the USEPA's Guideline on Air Quality Models will be used in the modeling analysis. The regulatory default option in AERMOD includes the use of stack-tip downwash, incorporates the effects of elevated terrain, and includes the calms and missing data processing routines.

Preprocessing programs associated with AERMOD include AERMAP (version 11103), AERSURFACE (version 13016), AERMET (version 13350) and AERMINUTE (version 11325). These are the most recent versions available. If the USEPA issues updated versions prior to the start of input data preprocessing for the Project, Magnolia will use updated versions.

3.5 SOURCE CHARACTERIZATION

All proposed emission sources will be modeled as point sources. The Project emission source inventory, heat input ratings and anticipated hours of operation are presented in Table 5. Magnolia is working with potential equipment vendors for the auxiliary boiler, thermal oxidizer, emergency use engines for the emergency generator and firewater pump, and for flares to develop final specifications and emission rates. Table 6 shows preliminary stack parameters for the Project emission sources as currently known. Draft emission rates for each source are shown in Appendix A; however, final source characteristics and maximum emission rates to be modeled will represent worst-case conditions and will be presented in the modeling report and permit application after the Best Available Control Technology (BACT) analysis has been completed.

Equipment Description

The gas turbines for the Project will be aero-derivative units produced by General Electric, model PGT25+G4. Each gas turbine will combust only pipeline quality natural gas and will be equipped with dry-low emissions (DLE) and a waste heat recovery unit. Each unit's heat input rating is shown in Table 5.

Magnolia is currently in the process of obtaining proposals from potential auxiliary boiler vendors; therefore, a specific unit has not been selected at this time. The data presented in this protocol are preliminary and subject to change upon final vendor selection. However, the data presented are reasonable approximations of the performance characteristics of the boiler.

Table 5 Emission Source Equipment Inventory – Magnolia LNG Project

Equipment Type	Quantity On-Site	Heat Input Rating (MMBtu/hr)[(a)]	Expected Annual Hours of Operation
Gas Turbine	8	318.42	8,760
Auxiliary Boiler	4	96	8,760
CO_2 Vent/Thermal Oxidizer	4	20.2	8,760
Diesel Engine Firewater Pump	1	1.85	<100
Diesel Engine Emergency Generator	1	7.42	<100
Marine Flare	1	To Come	<100
Process Flare	1	To Come	<100

Note: (a) Based on higher heating value (HHV) of 1,043 Btu/scf.

Key:
Btu/scf = British thermal units per standard cubic foot
CO_2 = carbon dioxide.
MMBtu/hr = million British thermal units per hour.

Table 6 Preliminary Stack Parameter Values for Project Emission Sources

Emission Source	Stack Height (meters)	Stack Diameter (meters)	Exit Velocity (meters per second)	Exit Temperature (degrees Celsius)
Gas Turbine (each)	27	3.3	25	196
Auxiliary Boiler (each)	25	1.2	~15	149
CO_2 Vent/Thermal Oxidizer (each)	23	0.3	TBD	TBD
Cryogenic Flare	33	note 1	20	1,000
Process Flare	33	note 1	20	1,000
Emergency Generator Engine	TBD	TBD	TBD	TBD
Firewater Pump Engine	TBD	TBD	TBD	TBD

Notes:
1) Effective stack diameter to be based on calculation procedure contained in section 5.9.4 of LDEQ 2006 modeling guidance which relates resulting stack diameter to total heat release of gas being flared.

Key:
CO_2 = carbon dioxide
TBD = to be determined

The auxiliary boilers in each liquefaction train would combust a mixture of high British thermal unit (Btu) (feed gas and rich gas) and low Btu (holding and ship loading) fuel using low NO_X burners. The boiler efficiency will be approximately 84 percent. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has not been developed. For the preliminary potential to emit estimate, it is assumed the composition of the fuel gas is primarily feed gas with the waste gas stream from the carbon dioxide removal system. Blending in rich gas and low Btu gas would alter the potential to emit slightly, estimated as varying by no more than 5 to 10 percent. The fuel gas stream burned in the auxiliary boiler may also contain trace amounts of benzene, toluene, ethylbenzene, and xylene (BTEX) from the carbon dioxide removal system. The estimated destruction efficiency for these hazardous air pollutants (HAPs) in the combustion process is 99.99 percent.

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. Contaminated CO_2 (containing BTEX) would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement would allow the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation, resulting in a NO_X concentration of approximately 40 parts per million by dry volume at 3 percent oxygen. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Other necessary control devices and programming would be provided to ensure that the system would start and operate safely according to National Fire Protection Association 85/86 guidelines. The thermal oxidizer vendor has not been selected at this time.

The marine and process flare will not be used during normal operation; however, a small pilot light will be continuously lit should flaring be needed. Flaring is not used during normal operation because the boil-off-gas generated from the LNG tank will be used as fuel gas in the auxiliary boiler. However, when maintenance is required, process lines may need to be manually vented and purged. There may also be occasions of automated venting from Pressure Relief Valves, Process Shutdowns, and Emergency Shutdown. During these events, flaring will be necessary. Magnolia is developing an estimate of the frequency of flaring that will be included in the final modeling protocol. Modeling guidance for flares from section 5.9.4 of the LDEQ modeling guidance will be used if flares are included in the worst-case modeling condition.

Vendors have not been selected for the emergency generator set or the diesel firewater pump.

3.6 EFFECTS OF NEARBY FACILITIES

Effects of nearby facilities will not be included in the preliminary dispersion modeling analysis for comparison to the SILs. If the preliminary dispersion modeling analysis shows significant impacts, an additional protocol will be submitted for the refined analysis that includes contributions from nearby facilities for comparison to PSD increment consumption.

3.7 TOXIC AIR POLLUTANT ANALYSIS

Louisiana Administrative Code Part III, Chapter 51 addresses emissions and analysis of toxic air pollutants (TAPs). Chapter 51 is applicable to major sources of TAPs, which are defined in Louisiana Administrative Code (LAC) 33:III.5103 as emission of any individual TAP at or above 10 tpy or the combination of all TAPs if equal to or above 25 tpy. The current emission inventory shown in Table 1 shows that total TAPs are estimated at 16 tpy. Emissions of individual TAPs are presented in Appendix A; the single TAP emitted in the largest quantity is formaldehyde at 8.2 tpy. Both the total TAPs and the individual TAP emitted in the largest amount are below the major source applicability thresholds specified in LAC 33:III.5103. Therefore, a TAP analysis for TAPs over the minimum emission rates as specified in LAC 33:III.5112 is not required for the Project. As the emission inventory is finalized, the total TAP and individual TAP emissions will be reviewed in comparison to Chapter 51 major source applicability thresholds. If a modeling analysis for TAPs becomes necessary, a supplement to this Protocol will be provided to the LDEQ.

4 AERMOD MODELING OPTIONS

4.1 BUILDING DOWNWASH

Building downwash effects will be considered in the modeling analysis. Structures and buildings will be included in the analysis when the distance between modeled stacks and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. The Building Profile Input Program with Prime (BPIP-PRIME) will be used to calculate direction-specific building dimensions and good engineering practice stack heights. AERMOD uses the output from BPIP-PRIME to calculate building downwash effects.

Due to the compact footprint of each liquefaction train, each train will be considered as a solid building for input to BPIP-PRIME. Each liquefaction train has a maximum dimension of approximately 166 meters (545 feet) and minimum dimension of 44 meters (144 feet).

4.2 TERRAIN

The terrain surrounding the proposed Project location up to 50 kilometers in any direction is best described as flat. A preliminary evaluation of terrain heights indicates most terrain elevations are between 0 feet and 20 feet in a 50-kilometer radius; there is a slight rise in elevation to the northwest with terrain reaching 40 to 50 feet at a distance of approximately 35 to 40 kilometers away. According to section 5.7 of the LDEQ Air Quality Modeling Procedures, requirements to consider terrain elevations are determined on a case-by-case basis. For the Project location in the Southwest Regional office region, the LDEQ typically does not require use of terrain data in dispersion modeling. However, after discussion with the LDEQ regarding implementing terrain data in flat terrain areas, Magnolia proposes to use the AERMOD Terrain Preprocessor (AERMAP Version 11103) to assign terrain elevations of source, building, and receptor locations. U.S. Geological Survey (USGS) 7.5-minute digital elevation models (DEMs) would be used for processing in AERMAP. The Project datum would be in North American Datum of 1983-Universal Transverse Mercator coordinates.

4.3 METEOROLOGICAL DATA

AERMOD will be run with surface meteorological data and upper air data from the Lake Charles Regional Airport. The airport is approximately 4.6 miles (7.5 kilometers) east-northeast of the Project site. Surface observation data will be obtained from the National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Database. Upper air data will be obtained from the NOAA Earth System Research Laboratory radiosonde observation database. A five-year dataset will be used, encompassing the period 2008 through 2012. If 2013 data are available for upper air and surface datasets, the five-year dataset will comprise years 2009 through 2013.

The processing steps to be used include determining land surface characteristics followed by processing of the land surface characteristics; surface and upper air meteorological data. The USEPA AERSURFACE program (version 13016) will be used to determine the surface

characteristics surrounding the Project site. AERSURFACE processes land cover data to determine the surface characteristics for use in AERMET. AERSURFACE uses a 1-kilometer radius surrounding the site to determine surface roughness values for each direction sector, and a 10-by-10-kilometer area to determine the mid-day albedo and daytime Bowen Ratio. AERSURFACE will be run for month-specific surface characterization. The AERMET (Version 13350) pre-processor will then be used to prepare meteorological data for use in AERMOD. Output from AERSURFACE will be input to AERMET along with surface and upper air meteorological observation data. Guidance provided in the most recent AERMOD Implementation Guide (USEPA 2009) will be followed.

Surface wind data sets will consist of automatic surface observing system (ASOS) 1-minute wind data from the Lake Charles Regional airport. These data sets will be processed using the AERMINUTE data pre-processor program for subsequent use in Stage 2 of AERMET data processing.

4.4 RECEPTORS

Impacts will be analyzed at receptors placed along and beyond the fence line of the Project site. Guidance provided by the USEPA describing locations considered as ambient air will be followed. In general, the guidance states that any property owned by the Project within a fenced in area (or area with public access controlled by other means) is not considered ambient air; locations outside of fenced-in locations owned by the Project are considered ambient air, including over-water locations.

The initial receptor grid will be established using a Cartesian grid at the following intervals:

- Along fence line: 100-meter spacing.
- Fence line to 1 kilometer beyond fence line: 100-meter spacing.
- From 1 kilometer to 5 kilometers beyond fence line: 500-meter spacing.
- From 5 kilometers to 10 kilometers beyond fence line: 1-kilometer spacing.

If the initial modeling indicates ambient concentrations remain above the applicable SIL beyond 10 kilometers, the receptor grid will be extended to determine the full extent of the area of influence, not to exceed 50 kilometers (the geographic/dispersion limit of the model) from the Project fence line. SILs are defined by the USEPA as ambient concentrations of air pollutants above which the potential for a significant air quality impact is deemed possible. It follows that if modeled ambient concentrations of air pollutants are below a SIL, a significant air quality impact is not likely and no further modeling is required. If the maximum concentration occurs beyond 1 kilometer of the fence line, then an additional receptor grid with 100-meter spacing will be set up, centered on the receptor with the maximum impact to ensure the maximum impact is identified. Receptor elevations will be determined using AERMAP as discussed in Section 4.2.

The Mossville environmental justice community is located approximately 7 miles (11.3 kilometers) north of the Project site. The initial receptor grid outlined above will extend to 6.2

miles (10 kilometers) from the Project site. As noted in the preceding paragraph, if modeled impacts are above the applicable SIL at 6.2 miles (10 kilometers), the receptor grid will be extended so that ambient concentrations at receptors beyond 6.2 miles (10 kilometers), including the Mossville area, will be determined. Discrete (i.e., individual) receptors will be placed in the Mossville community to supplement the extended grid.

4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS

Emissions from a combustion source are primarily composed of two compounds, nitrogen oxide (NO) and nitrogen dioxide (NO_2), that are added together to determine total NO_X. The primary component of NO_X in the stack is NO. However, the NAAQS for this class of compounds has been established for NO_2 since NO_2 is the photochemically reactive form of NO_X that participates in ozone formation.

The USEPA has established a three tier procedure for determining the quantity of NOx emitted from an emission source that ultimately converts to NO_2 as described in the USEPA Guideline on Air Quality Models. Although the procedure was originally established to address the former annual NO_2 NAAQS, the procedures are still considered technically appropriate for the short-term NO_2 NAAQS. The tiered approach is intended to act as a screening procedure, with Tier 1 providing the most conservative result. Tiers 2 and 3 are used if unacceptable results are realized from Tier 1.

In Tier 1, full conversion of NO_X to NO_2 is assumed in modeling. If the NAAQS for NO_2 is exceeded, then the refined technique found in Tier 2 is applied.

In Tier 2, the Tier 1 1-hour modeled results will be multiplied by a NO_2 to NO_X ambient equilibrium ratio of 0.8 as recommended by the LDEQ. As in Tier 1, if the modeled results show an exceedance of the NAAQS, Tier 3 is applied.

Tier 3 consists of applying one of two non-default techniques available in the latest version of AERMOD that account for the atmospheric chemistry relationship between the conversion of NO_X to NO_2 and ambient ozone concentrations. Use of Tier 3 requires review by the USEPA as well as the LDEQ. Both techniques are fundamentally based on the limitation of NO_X to NO_2 conversion by the ambient ozone concentration and in-stack NO_X conditions. The Ozone Limiting Method (OLM) procedure applies a series of steps to determine the amount of NO_X that ultimately converts to NO_2 based on the amount of ozone present in the atmosphere. Conversion of NO_X to NO_2 is "limited" if the modeled NO_X concentration is greater than the ambient ozone concentration. The second ozone method under Tier 3 is the Plume Volume Molar Ratio Method (PVMRM). The PVMRM method takes into account more detailed information regarding the atmospheric chemistry processes in the plume resulting in conversion of NO_X to NO_2. For both Tier 3 methods, a value for the ambient ozone concentration is required.

For this project, the modeling analysis will apply each tier when modeling NO_2 in sequence, as necessary to demonstrate compliance with the NO_2 NAAQS. If Tier 3 becomes

necessary, Magnolia will provide a supplement to this protocol to address data assumptions for the Tier 3 methodology. Proposed data to be discussed would include:

- Background ozone concentration;
- NO_2 to NO_X equilibrium ratio; and
- In-stack NO_2 to NO_X ratio for each modeled source emitting NO_X;

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS

5.1 CLASS I

In addition to the comparison against ambient air quality standards for Class II modeling, an analysis of air quality impacts to Class I areas must also be assessed. Class I areas include locations under the jurisdiction of the United States Fish and Wildlife Service, United States Forest Service, and the National Park Service. The Class I designation has also been given to specific Native American lands that have been determined to require special treatment for air quality purposes. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, distances greater than 300 kilometers between an emission source and a Class I area precludes the need for further Class I air quality analyses. For a source to Class I distance greater than 400 kilometers, the FLAG screening test (Q/d) is not required. Therefore, due to the separation distance of greater than 400 kilometers, a Class I air quality screening analysis and refined impact assessment will not be required.

5.2 ADDITIONAL IMPACT ANALYSIS

Magnolia will prepare an additional impact analysis following the guidelines in Chapter D of the USEPA New Source Review Workshop Manual (USEPA 1990) to address growth and associated ambient air quality impacts, soils and vegetation impacts and visibility impairment. The growth analysis will consider the Project's potential impact and emissions associated with growth of industrial, commercial and residential sectors as a result of the Project. The soils and vegetation assessment will consider the modeled ambient concentration resulting from the Project in comparison to secondary NAAQS that have been established for the purpose of protecting plants and animals from harm due to air quality. The visibility impairment analysis will consist of a determination of the visual quality in the area and an initial screening-level assessment of the possibility of visibility impairment. If necessary, a more in-depth analysis following procedures in the USEPA's Workbook for Plume Visual Impact Screening and Analysis (USEPA 1992) would be performed if initial screening indicated a potential impact.

6 REPORTING OF RESULTS

The air quality modeling analysis will be documented in a report that includes a summary narrative and a tabulation of the model results to demonstrate compliance with the applicable ambient air quality standards and other thresholds. The report will include the following elements:

- Detailed description of the proposed activity and emission sources with specific parameters used in the analysis including emission rates, stack heights, stack diameters, temperatures, exit velocities, and nearby building dimensions;
- Facility plot plan showing the location of emission sources, facility buildings, fence line corners, and terrain characteristics;
- Map (i.e., USGS with 1:24,000 scale) showing the facility location and receptors used in the analysis;
- Description of the model(s) selected and rationale for selection;
- Description of the site topography and receptor grids used in the analysis;
- Description of meteorological data;
- Technical support documentation for any assumptions made in the modeling analysis which deviate from the stated guidance; and
- Summary of model predictions showing comparison to applicable ambient air quality standards.

Digital copies of relevant model files will be included with the report, such as, but not limited to:

- Facility plot plan (in geo-referenced digital format);
- Meteorological files (.SFC and .PFL);
- Terrain files (USGS DEM files);
- Geo-referenced maps;
- Files related to BPIP-PRIME runs; and
- AERMOD model generated input and output files.

Reports and applicable digital files will be submitted to the LDEQ as part of the permit-to-construct application.

7 REFERENCES

Louisiana Department of Environmental Quality (LDEQ). n.d. LDEQ webpage: Southwest Air Monitoring Sites. http://www.deq.louisiana.gov/portal/tabid/2478/Default.aspx. Accessed December 3, 2013.

———. 2006. Air Quality Modeling Procedures. LDEQ Air Quality Assessment Division. August 2006.

United States Environmental Protection Agency (USEPA). 1990. New Source Review Workshop Manual – Draft, Prevention of Significant Deterioration and Nonattainment Area Permitting. New Source Review Section, Air Quality Management Division.

———. 1992. Workbook for Plume Visual Impact Screening and Analysis (Revised). http://www.epa.gov/ttn/scram/userg/screen/WB4PlumeVisualOCR.pdf. Accessed December 9, 2013.

———. 2005. Guideline on Air Quality Models. 40 CFR 51, Appendix W. November 2005.

———. 2010a. EPA Guidance Concerning the Implementation of the 1-Hour NO_2 NAAQS for the Prevention of Significant Deterioration Program. Memorandum dated June 29, 2010 from Stephen Page (USEPA) to Regional Air Division Directors.

———. 2010b. Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS. Memorandum dated March 23, 2010, from Stephen Page (USEPA) to USEPA Regional Modeling Contacts and other addressees.

———. 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard. Memorandum dated March 1, 2011, from Tyler Fox (USEPA) to Regional Air Division Directors.

———. 2013a. Draft Guidance for $PM_{2.5}$ Permit Modeling. Memorandum dated March 4, 2013, from Stephen Page (Director, Office of Air Quality Planning and Standards to various addresses (as listed in memorandum).

———. 2013b. Circuit Court Decision on PM2.5 Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers. March 4, 2013. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards.

This page left blank intentionally.

Appendix A
Preliminary Operational Emission Estimates

This page left blank intentionally.

Table A1
Preliminary Potential Operation Emissions (tons per year) – Magnolia LNG

Emission Source	NO_X	CO	SO2	PM10	PM2.5	VOC	HAPs	CO2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator (1)	1.5	3	0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump (1)	0.7	1.5	0	0.01	0.01	0.4	0.06	125
Total	1,119	813	33	90	90	57	16	1,559,837

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

Parameter		Units	Value
Fuel Lower Heating Value (LHV)[1]		Btu/scf	935.1
Fuel Higher Heating Value (HHV) [1]		Btu/scf	1036.4

Parameter	Units	Turbine 1	Number of Turbines	Total for Eight Turbines
Hourly Fuel Flow (LHV) - Maximum[2]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (LHV) - Average[3]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (HHV) - Maximum[4]	MMBtu/hr	318.42	8	2,547
Hourly Fuel Flow (HHV) - Average[4]	MMBtu/hr	318.42	8	2,547
Annual Operation @ 100% Load	hr/yr	8760	8	70,080
Maximum Annual Fuel Flow (LHV)[5]	MMBtu/yr	2,516,748	8	20,133,984
Maximum Annual Fuel Flow (HHV)[6]	MMBtu/yr	2,789,389	8	22,315,112
Maximum Annual Fuel Flow (volume)[6]	MMscf/yr	2,690	8	21,520

Pollutant Type	Pollutant	LHV Emission Factor (lb/MMBtu)	HHV Emission Factor[7,8,9] (lb/MMBtu)	Each Turbine: Maximum Hourly Emission Rate (lb/hr)	Each Turbine: Maximum Annual Emissions (tpy)	Eight Turbines: Annual Emissions (tpy)	
Criteria	NO_X			29.00	127.02	1016.2	
	CO			18.24	79.89	639.1	
	VOC			1.28	5.61	44.9	
	PM	-	0.0066	2.10	9.20	73.6	
	PM_{10}	-	0.0066	2.10	9.20	73.6	
	$PM_{2.5}$	-	0.0066	2.10	9.20	73.6	
	SO_2	-	0.0028	0.90	3.93	31.5	
HAPs	Acetaldehyde	-	0.000040	0.013	0.056	0.4	
	Acrolein	-	0.0000064	0.002	0.009	0.1	
	Benzene	-	0.000012	0.004	0.017	0.1	
	Ethylbenzene	-	0.000032	0.010	0.045	0.4	
	Formaldehyde	-	0.00071	0.226	0.990	7.9	
	Toluene	-	0.00013	0.041	0.181	1.5	
	Xylenes	-	0.000064	0.020	0.089	0.7	
	Total HAPs	-	**-**	**0.3166**	**1.387**	**11.095**	
Greenhouse Gas	CO_2			37218	163,015	1304118.7	
	N_2O	-	0.003	0.96	4.18	33.5	CO_2e
	CH_4	0.028	0.0255	5.13	22.46	179.7	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-	-	37,218	163,015	1,304,119	1
	N_2O	-	-	296	1,297	10,377	310
	CH_4	-	-	108	472	3,773	21
	Total GHGs	-	**-**	**37,622**	**164,784**	**1,318,269**	

Notes:
1. Data from GE PGT25+G4 DLE Expected Emissions.xlsx sheet (based on Fuel Number 800-41 Magnolia).
2. Data from GE PGT25+G4 Turbine Specification Sheets. Fuel flow based on inlet temperature chilled to 15.0 °C dry bulb.
3. Inlet cooling to be used to maintain inlet temperature, therefore little variation between hourly maximum and annual average.
4. Calculated from hourly fuel flow (LHV basis) and ratio of HHV to LHV.
5. Maximum annual fuel flow for each turbine calculated by multiplying maximum hourly fuel (LHV) by annual operation @ 100% load.

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

6. Calculated from maximum annual fuel flow (LHV).
7. NO_X, CO, VOC, and CH_4 emission factors from GE PGT25+G4 Turbine Specification Sheets.
8. CO_2 emission factor from GE PGT25+G4 DLE Expected Emissions.xlsx.
9. Emissions factors from United States Environmental Protection Agency (EPA). 2000. AP 42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensable and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensable and filterable fractions). SO_2 emission factor based on sulfur content of 0.003%.

Table A3
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		1000	kW
		1341	
Engine Fuel Flow Rate (HHV)[1]		5,534	Btu/hp-hr
		7.42	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	5.91	1.5	
	CO	-	4.0	11.8	3.0	
	VOC	-	1.0	2.96	0.7	
	PM	0.00999	-	0.073	0.018	
	PM_{10}	0.00999	-	0.073	0.018	
	$PM_{2.5}$	0.00999	-	0.073	0.018	
	SO_2	0.000588	-	0.0043	0.0011	
HAPs	Acetaldehyde	0.00836	-	0.061	0.015	
	Acrolein	0.00514	-	0.038	0.009	
	Benzene	0.000440	-	0.0032	0.0008	
	Ethylbenzene	0.0000397	-	0.00029	0.000072	
	Hexane	0.00111	-	0.008	0.0020	
	Formaldehyde	0.0528	-	0.39	0.10	
	Toluene	0.000408	-	0.0030	0.00074	
	Xylenes	0.000184	-	0.0013	0.00034	
	Total HAPs	**-**	**-**	**0.50**	**0.13**	
Greenhouse Gas	CO_2	110	-	803	201	CO_2e
	CH_4	1.25	-	9	2.3	Multiplier
Greenhouse	CO_2	-	-	803	201	1
Gas	CH_4	-	-	192	48	21
(CO_2e)	**Total GHGs**	**-**	**-**	**995**	**249**	

Notes:
1. Estimated based on typical unit.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A4
Emissions for Fire Water Pump Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		500	kW
		670	
Engine Fuel Flow Rate (HHV)[1]		2,767	Btu/hp-hr
		1.85	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	2.95	0.7	
	CO	-	4.0	5.9	1.5	
	VOC	-	1.0	1.48	0.4	
	PM	0.00999	-	0.018	0.005	
	PM_{10}	0.00999	-	0.018	0.005	
	$PM_{2.5}$	0.00999	-	0.018	0.005	
	SO_2	0.000588	-	0.0011	0.0003	
HAPs	Acetaldehyde	0.00836	-	0.015	0.004	
	Acrolein	0.00514	-	0.009	0.002	
	Benzene	0.000440	-	0.0008	0.0002	
	Ethylbenzene	0.0000397	-	0.00007	0.000018	
	Hexane	0.00111	-	0.002	0.0005	
	Formaldehyde	0.0528	-	0.10	0.02	
	Toluene	0.000408	-	0.0007	0.00019	
	Xylenes	0.000184	-	0.0003	0.00008	
	Total HAPs	**-**	**-**	**0.12**	**0.03**	
Greenhouse Gas	CO_2	110	-	201	50	CO_2e
	CH_4	1.25	-	2	0.6	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-	-	201	50	1
	CH_4	-	-	48	12	21
	Total GHGs	**-**	**-**	**249**	**62**	

Notes:
1. Estimate.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensible and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A5
Emissions for Thermal Oxidizer
Magnolia LNG

Parameter	Value	Units
Fuel Flow Rate (HHV)[1]	20.23	MMBtu/hr
Higher Heating Value (HHV)[2]	1043	Btu/scf
Maximum Yearly Operation	8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMBtu)	Maximum Hourly Emission Rate (each)[4] (lb/hr)	Annual Emissions for Four Units (tpy)	
Criteria	NO_X	50.00	0.0501	1.01	17.8	
	CO	84.000	0.0842	1.70	29.8	
	VOC	5.5000	0.0055	0.11	2.0	
	PM	7.6	0.0076	0.15	2.7	
	PM_{10}	7.6	0.0076	0.15	2.7	
	$PM_{2.5}$	7.6	0.0076	0.15	2.7	
	SO_2	0.600000	0.0006	0.01	0.2	
HAPs	2-methylnapthalene	0.000024	0.000000	0.0000	0.000	
	Anthracene	0.000002	0.000000	0.0000	0.000	
	Benzene	0.0021	0.000002	0.0083	0.145	
	Dichlorobenzene	0.0012	0.000001	0.0000	0.000	
	Hexane	1.8000	0.001804	0.0365	0.640	
	Formaldehyde	0.0750	0.000075	0.0015	0.027	
	Napthalene	0.0006	0.000001	0.0000	0.000	
	Toluene	0.0034	0.000003	0.0244	0.427	
	Xylene	0.0000	0.000000	0.0280	0.490	
	Total HAPs	**-**		**0.07**	**1.24**	
Greenhouse Gas	CO_2	120000	120.2999	2433.67	42,637.840	CO_2e
	N2O	0.64	0.0006	0.01	0.227	
	CH_4	2.30	0.0023	0.05	0.817	Multiplier
Greenhouse	CO_2	-		2,434	42,638	1
	N2O			4	70	310
Gas	CH_4	-		1	17	21
(CO_2e)	**Total GHGs**	**-**		**2,439**	**42,725**	

Notes:
1. Estimate from preliminary design data from Magnolia LNG.
2. Based on HHV for feed gas for project used for aux boiler and thermal oxidizer spec.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A6: Estimated BTEX Destruction Efficiency

	Aux. Boiler Fuel			Thermal Oxidiser		
Destruction Efficiency		**99.99%**			**99.00%**	
	INLET	**OUTLET**		**INLET**	**OUTLET**	
	Mass Flow (kg/hr)	**Mass Flow, t/yr**		**Mass Flow (kg/hr)**	**Mass Flow, t/yr**	
CO2	0.005			10502.0366		
Nitrogen	0.014			0.0000		
Methane	73.511			5.4082		
Ethane	75.195			0.5032		
Propane	79.130			0.1054		
i-Butane	67.528			0.0000		
n-Butane	103.827			0.0000		
i-Pentane	199.821			0.0000		
n-Pentane	347.825			0.0000		
n-Hexane	534.789		lb/hr	0.0000		lb/hr
Benzene	137.574	0.121	0.030329	0.3735	0.033	0.008234
Cyclohexane	50.163	0.044	0.011059	0.0000		
n-Heptane	227.860			0.0000		
Toluene	41.926	0.037	0.009243	1.1015	0.096	0.024283
n-Octane	25.997			0.0000		
p-Xylene	16.108	0.014	0.003551	1.2691	0.111	0.027979
E-Benzene	16.108	0.014	0.003551	0.0000		
H2S	0.001			1.9553		
Ammonia	0.000			0.0000		
H2O	0.000			0.0000		
Total	**1997.382**	**0.229**		**10512.753**	**0.240**	
For 4 Trains		0.92			0.96	
Total MLNG Plant		**1.88**	**t/yr**			

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate [1]		92,130	ft3/hr
		96.00	MMBtu/hr
Higher Heating Value (HHV)[1]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMscf)	Maximum Hourly Emission Rate[4] (lb/hr)	Annual Emissions (tpy)	Annual Emissions Four Units (tpy)	
Criteria	NO_X	50	51.1275	4.71	20.6	82.53	
	CO	84	85.8941	7.91	34.7	138.64	
	VOC	5.5	5.6240	0.52	2.3	9.08	
	PM	7.6	7.7714	0.72	3.136	12.54	
	PM_{10}	7.6	7.7714	0.72	3.136	12.54	
	$PM_{2.5}$	7.6	7.7714	0.72	3.136	12.54	
	SO_2	0.60	0.6135	0.06	0.2476	0.99	
HAPs	2-methylnapthalene	0.000024	0.0000	0.00000	0.000	0.00	
	Anthracene	0.000002	0.0000	0.00000	0.000	0.00	
	Benzene	0.0021	0.0021	0.03053	0.1337	0.53	
	Cyclohexane	0.0000	0.0000	0.01106	0.0484	0.19	
	Dichlorobenzene	0.0012	0.0012	0.00011	0.000495	0.00	
	Ethylbenzene	0.0000	0.0000	0.00355	0.0156	0.06	
	Hexane	1.8000	1.8406	0.16957	0.7427	2.97	
	Formaldehyde	0.0750	0.0767	0.00707	0.03	0.12	
	Napthalene	0.0006	0.0006	0.00006	0.00	0.00	
	Toluene	0.0034	0.0035	0.00032	0.00140	0.01	
	Xylene	0.0000	0.0000	0.00355	0.0156	0.06	
	Total HAPs			**0.22**	**0.99**	3.96	
Greenhouse Gas	CO_2	120000	122705.8824	11304.89	49,515	198,062	
	N_2O	0.64	0.6544	0.06	0	1	CO_2e
	CH_4	2.30	2.3519	0.22	1	4	Multiplier
Greenhouse	CO_2			11,305	49,515	198,062	1
	N_2O			19	82	327	310
Gas	CH_4			5	20	80	21
(CO_2e)	**Total GHGs**			**11,328**	**49,617**	198,469	

Notes:
1. From Babcock & Wilcox P55-6356_BW_Budget_R01.pdf Oct 15 2013.

2. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
3. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by ratio of actual fuel heat value divided by 1020.

4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A8
Natural Gas Composition Data
Magnolia LNG

Component	Molar (Volume) Fraction[1] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Nitrogen	1.014	28.01	0.284	1.692
Carbon Dioxide	0.01	44.01	0.003	0.02
Methane	95.60	16.04	15.34	91.3
Ethane	2.56	30.07	0.770	4.58
Propane	0.32	44.10	0.143	0.852
I-Butane	0.091	58.12	0.053	0.316
N-Butane	0.091	58.12	0.053	0.316
I-Pentane	0.0811	72.15	0.059	0.348
N-Pentane	0.0811	72.15	0.059	0.348
Hexanes	0.035	95.96	0.033	0.197
Total	**99.9**	**-**	**16.79**	**100.0**

HAP Component	Molar (Volume) Fraction[2] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Benzene	0.00310	78.114	0.00242	0.0144
Ethylbenzene	0.00002	106.167	0.00002	0.000109
n-Hexane	0.00100	86.177	0.00086	0.0051
Toluene	0.00100	92.141	0.00092	0.00549
Xylenes	0.00100	106.167	0.00106	0.00632
Total HAPs	**0.0061**	-	-	**0.0315**

Component	Weight Fraction in Natural Gas (wgt %)	Weight Fraction in TOC (wgt %)
TOC	98.3	100
Methane	91.3	92.9
VOC	2.38	2.42
Benzene	0.0144	0.0147
Ethylbenzene	0.000109	0.000111
n-Hexane	0.005	0.005
Toluene	0.00549	0.00558
Xylenes	0.00632	0.00643
Total HAPs	0.0315	0.0320

Table A8
Natural Gas Composition Data
Magnolia LNG

Notes:

1. Based on Fuel Number 800-41 Magnolia provided by GE for PGT25+G4 DLE emissions.

2. Component split based on GRI GLY-Calc V4.0 lumped C6+ gas analysis multipliers for the Natural Gas Transmission Industry Segment.

This page left blank intentionally.

Appendix 9.C.2

Marine and Stationary Sources Air Quality Modeling Protocol

This page left blank intentionally.

K&L GATES

K&L GATES LLP
1601 K STREET, N.W.
WASHINGTON, DC 20006-1600
T 202.778.9000 F 202.778.9100 klgates.com

March 21, 2014

Sandra E. Safro
D 202.778.9178
F 202.778.9100
sandra.safro@klgates.com

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Magnolia LNG, LLC
PF13-9-000
Marine and Stationary Sources Air Modeling Protocol

Dear Secretary Bose:

Attached please find Magnolia LNG, LLC's ("Magnolia LNG") Marine and Stationary Sources Air Modeling Protocol ("Air Modeling Protocol"). The Air Modeling Protocol was prepared by Ecology and Environment, Inc., Magnolia LNG's environmental consultant, and describes the methods, pre- and post-processing programs, and model that will be used to determine the air quality impacts for the Magnolia LNG Project proposed in the docket number referenced above.

Any questions regarding this correspondence may be directed to the undersigned at 202.778.9178 or sandra.safro@klgates.com.

Best regards,

/s/ Sandra E. Safro
Sandra E. Safro
Counsel for Magnolia LNG, LLC

Enclosures

cc: Janine Cefalu, FERC

This page left blank intentionally.

MAGNOLIA LNG PROJECT

Marine and Stationary Sources Air Quality Modeling Protocol

March 18, 2014

Submitted to:

Federal Energy Regulatory Commission

Submitted by:

MAGNOLIA LNG

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

This page left blank intentionally.

TABLE OF CONTENTS

Section Page

Tables iv
Figures iv
Appendix iv
Acronyms and Abbreviations v

1 INTRODUCTION 1
1.1 OBJECTIVE 1
1.2 PROJECT DESCRIPTION 1
1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT 2
1.4 SOURCE DESIGNATION 5

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE 7
2.1 NEW SOURCE REVIEW 7
2.2 SHORT-TERM NAAQS MODELING GUIDANCE 7

3 MODELING METHODOLOGY 8
3.1 CLASS II MODELING GUIDANCE 8
3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS 8
3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS 11
3.4 MODEL SELECTION 12
3.5 SOURCE CHARACTERIZATION 12
3.6 EFFECTS OF NEARBY FACILITIES 16

4 AERMOD MODELING OPTIONS 17
4.1 BUILDING DOWNWASH 17
4.2 TERRAIN 17
4.3 METEOROLOGICAL DATA 17
4.4 RECEPTORS 18
4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS 19

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS 21
5.1 CLASS I 21
5.2 ADDITIONAL IMPACT ANALYSIS 21

6 REPORTING OF RESULTS 22

7 REFERENCES 23

TABLES

Page

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project 6
Table 2 State and National Ambient Air Quality Standards 8
Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project 10
Table 4 Ambient Air Monitoring Stations near Lake Charles 11
Table 5 Emission Source Equipment Inventory – Magnolia LNG Project.....15
Table 6 Preliminary Stack Parameter Values for Project Emission Sources 15

FIGURES

Page

Figure 1 General Location Map of the Magnolia LNG Project 2
Figure 2 Project Site Boundary Map 3
Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations 4

APPENDIX

A Preliminary Operational Emission Estimates

ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program with Prime
BTEX	benzene, toluene, ethylbenzene, and xylene
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DEM	digital elevation models
DFDE	dual fuel diesel electric
DLE	dry-low emissions
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
hp	horsepower
IMO	International Maritime Organization
KMLP	Kinder Morgan Louisiana Pipeline
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
LNG	liquefied natural gas
m^3	cubic meter(s)
Magnolia	Magnolia LNG, LLC
MARPOL	International Convention for the Prevention of Pollution from Ships
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NAECA	North American Emission Control Area
NEPA	National Environmental Policy Act
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration

NO_X	nitrogen oxide
NSR	New Source Review
OSMR®	Optimized Single Mixed Refrigerant
PM_{10}	particulate matter equal to or less than 10 micrometers aerodynamic diameter
$PM_{2.5}$	particulate matter equal to or less than 2.5 micrometers aerodynamic diameter
Port	Lake Charles Harbor & Terminal District
Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
PVMRM	plume volume molar ratio method
SIL	significant impact level
SMC	significant monitoring concentration
TAP	toxic air pollutant
tpy	tons per year
USCG	United States Coast Guard
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WSA	Waterway Suitability Assessment

1 INTRODUCTION

1.1 OBJECTIVE

Magnolia LNG, LLC (Magnolia) has prepared this protocol to describe the methods, pre- and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's air quality impacts. Although marine vessel sources are not regulated by federal or state air permitting regulations and associated ambient impact analysis requirements, the Federal Energy Regulatory Commission (FERC) has requested the inclusion of marine vessel emission sources in an air dispersion modeling analysis for National Environmental Policy Act (NEPA) purposes.

This protocol includes marine sources in the emission inventory to be modeled, but otherwise mirrors the stationary source protocol submitted to the Louisiana Department of Environmental Quality (LDEQ) in terms of methodology, stationary source input data to be used, model to be used, receptor grid, terrain data and meteorological data. Model results will be compared to significant impact levels (SILs), and, for impacts above applicable SILs, used to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels. The protocol is based on the current United States Environmental Protection Agency's (USEPA's) Guideline on Air Quality Models (USEPA 2005), the USEPA's New Source Review Workshop Manual (1990), various recent USEPA memoranda regarding modeling procedures for short term standards analysis, and the LDEQ's Air Quality Modeling Procedures (the latter as updated by discussions with LDEQ) (LDEQ 2006).

1.2 PROJECT DESCRIPTION

Magnolia is proposing to develop a natural gas liquefaction facility in Lake Charles, Calcasieu Parish, Louisiana, on a tract of land that was previously used by the United States Army Corps of Engineers (USACE) as a confined disposal facility (CDF) to dispose dredge materials of the adjacent Industrial Canal. Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants.

The Magnolia LNG Project (referred to herein as the Project) facility would be capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of liquefied natural gas (LNG). Magnolia would use its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology to produce LNG. The Project would receive natural gas via an existing pipeline that passes beneath the Project site near the southern boundary. Associated with the Project, Kinder Morgan Louisiana Pipeline (KMLP) would develop a compressor station in Eunice Louisiana, approximately 52 miles from the Project site. Permitting and any modeling required for the KMLP Eunice compressor station would be undertaken directly by KMLP and filed separately with the FERC.

The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1 is a general location map of the Project.

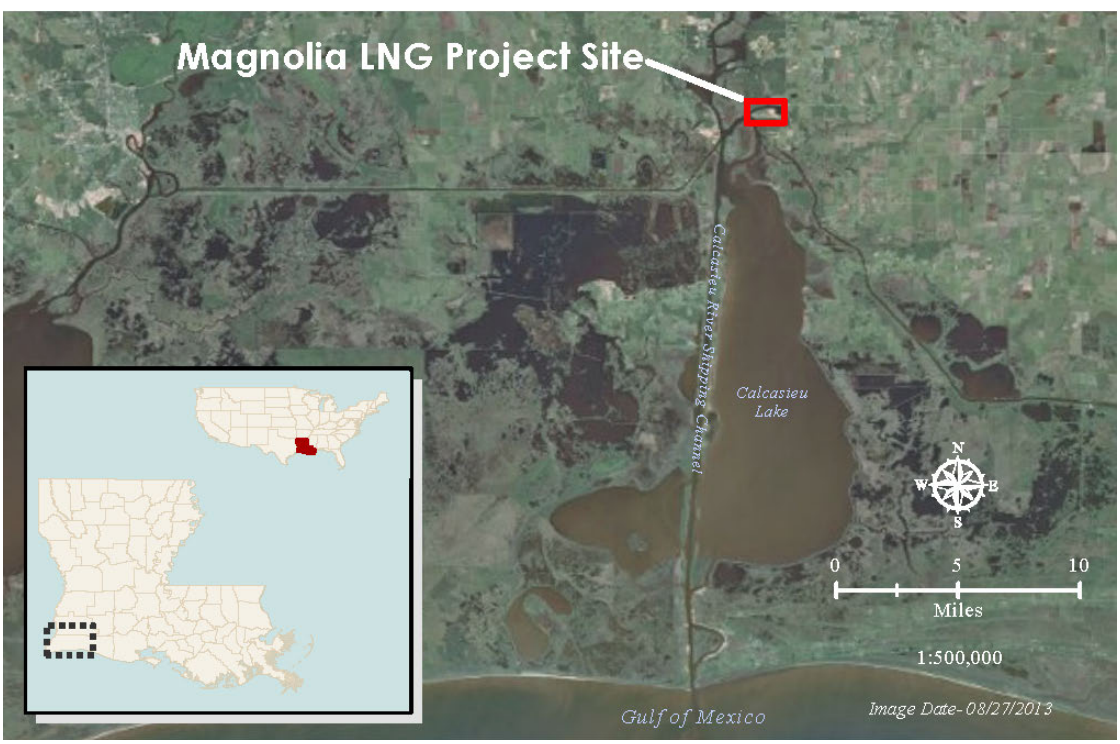


Figure 1 General Location Map of the Magnolia LNG Project

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement (Option Agreement) with the Port for the Project site. The Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each, for a total of 70 years. The expected operational life of the Project is a minimum of 30 years. Figure 2 shows the boundary of the lease area.

Magnolia has prepared a preliminary layout of equipment on the leased area. Figure 3 shows the location of the emission sources to be modeled for the Project analysis and air permit application. In addition to the stationary sources illustrated on Figure 3, an LNG carrier is shown in the berth directly north of the LNG storage tanks. Note the orientation of the carrier with the bow pointed west and the exhaust stack located on the stern. This orientation will be used to model the LNG carrier. Tug boats accompanying the LNG carrier (not shown on Figure 3) would be released to return to port or other duties after the LNG carrier is moored at the loading dock. Although not illustrated on Figure 3, the LNG barge would be positioned in the same berth for loading of LNG onto barges. One tug would remain with the barge during loading and will be modeled as being positioned at the aft end of the barge.

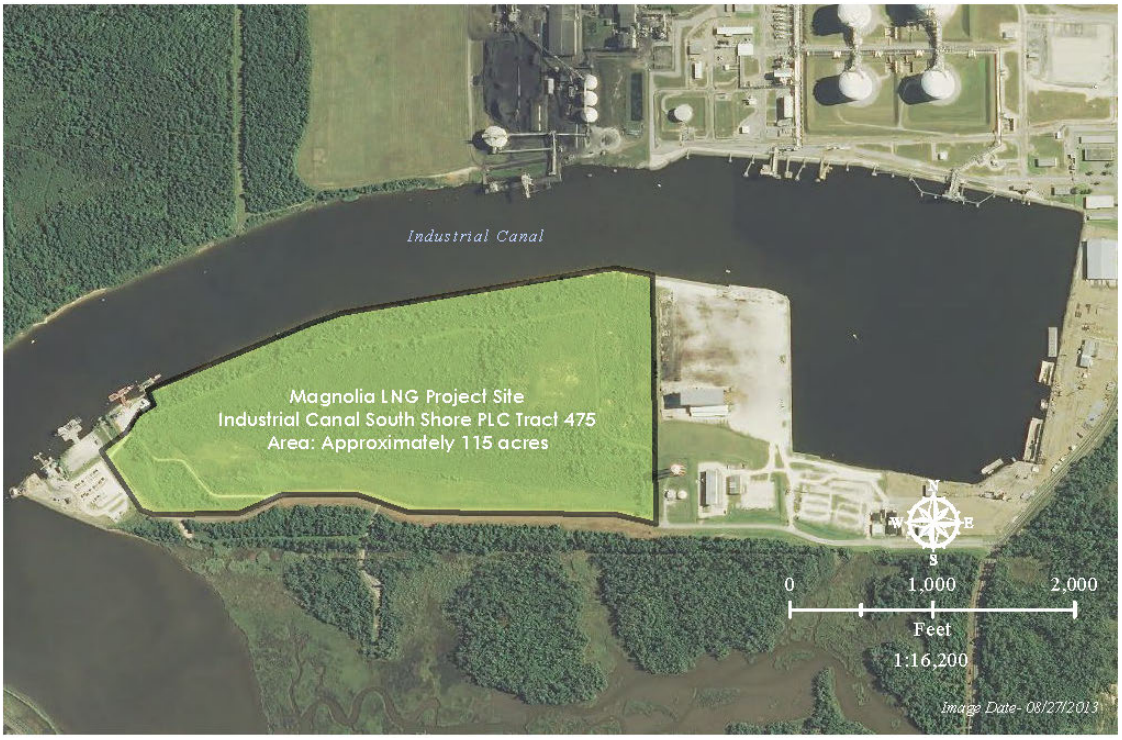


Figure 2 Project Site Boundary Map

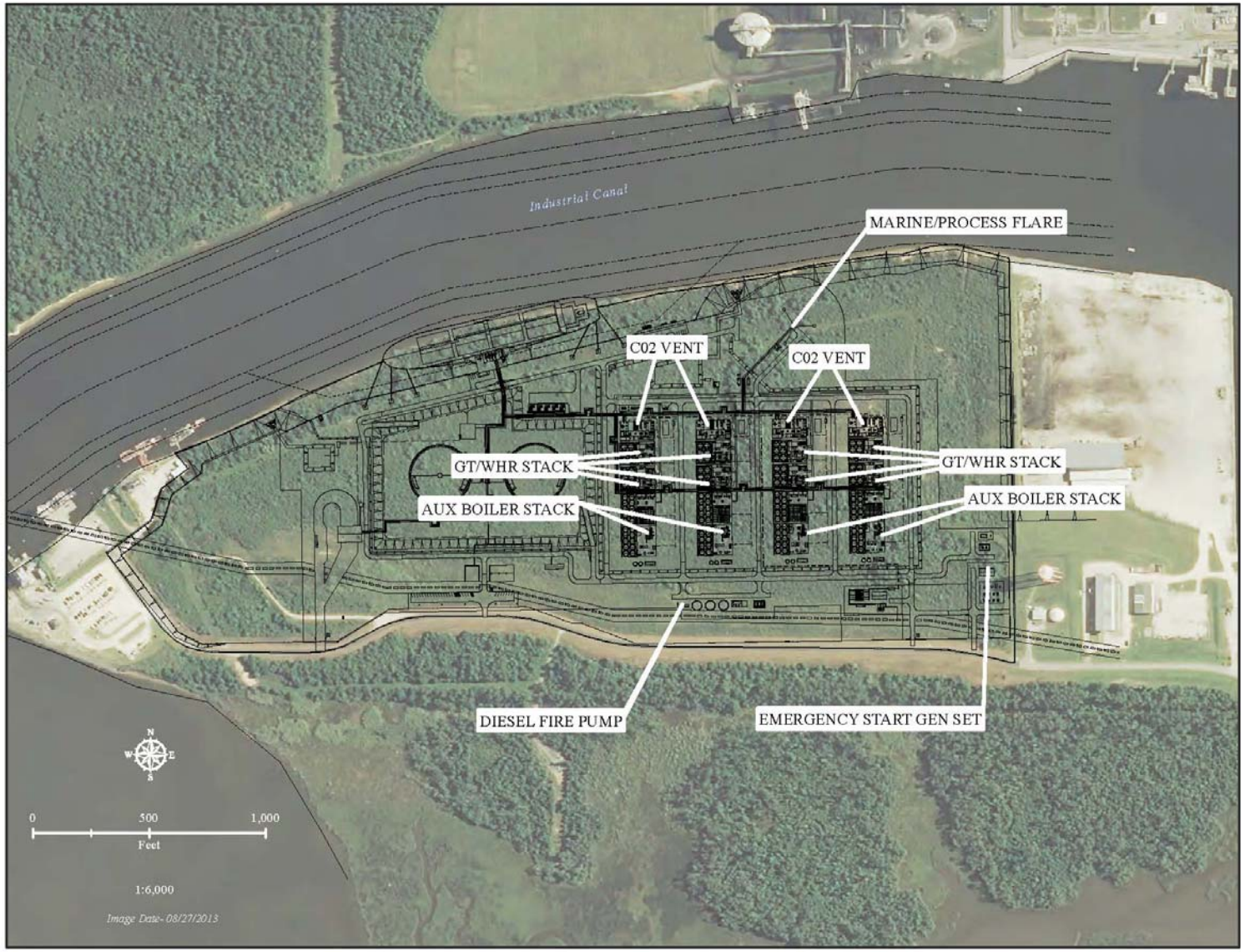


Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations

1.4 SOURCE DESIGNATION

Initial potential to emit (PTE) estimates and Project location in an attainment area for all criteria pollutants indicate that a PSD modeling analysis will be required for the criteria pollutants nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter equal to or less than 10 micrometers aerodynamic diameter (PM_{10}), and particulate matter equal to or less than 2.5 micrometers aerodynamic diameter ($PM_{2.5}$). Emissions of greenhouse gas (GHG) also would be above PSD major source thresholds; however, GHGs are not currently subject to modeling requirements. Initial PTE for the Project is shown in Table 1. Note that emissions from mobile sources (the LNG carrier and the tug boats) associated with ship hoteling, docking, and undocking are not counted for PSD applicability purposes, and thus are listed after the PSD applicability determination total in Table 1. The initial estimate of marine source emissions included in draft Resource Report 9 has been revised with more detail and updated vessel activity information and is shown in Table 1. Emission calculation details are provided in Appendix A of this protocol.

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs	CO_2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator	1.5	3.0	0.0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump	0.7	1.5	0.0	0.01	0.01	0.4	0.06	125
Flares	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Project Total	**1,119**	**813**	**33**	**90**	**90**	**57**	**16**	**1,559,837**
PSD Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**N/A**	**100,000**
Trigger PSD?	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	**N/A**	**YES**
Significant Emission Rate	**40**	**100**	**40**	**15**	**10**	**40**	**N/A**	**N/A**
PSD Modeling Required?	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**N/A**	**N/A**
LNG Carrier Hoteling	**6.9**	**5.4**	**0.8**	**0.3**	**0.3**	**2.4**	**N/A**	**1,984**
LNG Carrier Maneuvering near/at Dock	**0.5**	**0.4**	**0.2**	**0.02**	**0.02**	**0.1**	**N/A**	**112**
Tug Boats maneuvering w/Carrier at Dock	**43**	**5.4**	**1.7**	**1.6**	**1.6**	**2.0**	**N/A**	**2,336**
Tug Boat w/Barge near/at Dock	**16**	**2.0**	**0.5**	**0.6**	**0.6**	**0.7**	**N/A**	**863**

Key:
CO = carbon monoxide.
CO_2e = carbon dioxide equivalent.
HAPs = hazardous air pollutants.
LNG = liquefied natural gas.
N/A = Not applicable.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
PSD = Prevention of Significant Deterioration.
SO_2 = sulfur dioxide.
TBD = To be determined.
VOC = volatile organic compound.

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE

2.1 NEW SOURCE REVIEW

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the Clean Air Act. NSR must be addressed before construction can begin on new major stationary sources or major modifications to existing major stationary sources. The PSD program is the NSR permitting program for stationary sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For stationary sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Stationary emission source thresholds for nonattainment areas are lower than the stationary emission source thresholds for attainment areas. The Project location is unclassifiable/ attainment and, therefore, is compared to attainment area major stationary source NSR thresholds.

The major stationary source attainment area NSR thresholds are either 100 tons per year (tpy) or 250 tpy. The 100 tpy threshold applies only to 28 distinct stationary source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 stationary source categories; therefore, the applicable major stationary source threshold is 250 tpy per criteria pollutant and 100,000 tpy for carbon dioxide equivalent (CO_2e). Estimated stationary source operational emissions would be above 250 tpy for nitrogen oxide (NO_X) and CO and above 100,000 tpy for CO_2e (see Table 1); therefore, the Project is subject to major stationary source NSR attainment area (PSD) permitting.

Emissions from the marine sources (LNG carrier and tug boats) described in this protocol are not subject to inclusion in determining major stationary source status, since NSR only applies to stationary emission sources. It also should be noted that while the LNG carriers and tug boats are engaged in commerce with Magnolia, Magnolia does not control the operation of these vessels since they are owned and operated by separate entities and are subject to operation requirements imposed by the United States Coast Guard (USCG). These latter requirements are in the process of being developed and may result in somewhat different vessel operations during the docking and undocking process. As changes to vessel operations emerge as a result of these requirements, they will be accommodated in the modeling analysis.

2.2 SHORT-TERM NAAQS MODELING GUIDANCE

The USEPA has provided guidance for modeling methodology for the 1-hour NO_2 NAAQS in a series of memoranda (USEPA 2010a, 2011). The guidance provided in these memoranda describes procedures for processing and interpreting model results with regards to the statistical form of the 1-hour NO_2 NAAQS. The USEPA has also provided guidance for modeling to demonstrate compliance with the $PM_{2.5}$ NAAQS (USEPA 2010b). Magnolia will follow these procedures when modeling and processing model results.

3 MODELING METHODOLOGY

3.1 CLASS II MODELING GUIDANCE

The approach for the air quality modeling analysis is based on the USEPA's Guideline on Air Quality Models, incorporated as 40 CFR 51, Appendix W (USEPA 2005). Additional guidance documents to be used include the following:

- The LDEQ's Air Quality Modeling Procedures (LDEQ 2006), incorporating changes as discussed with the LDEQ and reflected in comments received from the LDEQ on the stationary source modeling protocol. These comments were incorporated and a revised and final modeling protocol submitted and approved by LDEQ (Approval letter of January 22, 2014).
- The USEPA memorandum on the guidance concerning the implementation of the 1-hour NO_2 NAAQS for the PSD program (USEPA 2010a).
- The USEPA memorandum on "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" (USEPA 2010b).
- The USEPA memorandum on "Draft Guidance for $PM_{2.5}$ Permit Modeling" (USEPA 2013a).
- The USEPA document regarding the "Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration – Questions and Answers" (USEPA 2013b).

3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS

NAAQS and/or Louisiana ambient air quality standards have been promulgated for the following criteria pollutants: CO, lead, NO_2, ozone, PM_{10}, $PM_{2.5}$, and SO_2. NAAQS and Louisiana ambient air quality standards are summarized in Table 2. Table 3 summarizes PSD class I and II increments, SILs, and monitoring de minimis concentrations.

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
CO	8-hour	10,000	9[(a)]	-		Same as Primary NAAQS
	1-hour	40,000	35[(a)]	-		Same as Primary NAAQS
Lead	Rolling 3-month average	0.15	-	Same as Primary NAAQS		Same as Primary NAAQS

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
NO_2	Annual	100	0.053	Same as Primary NAAQS		Same as Primary NAAQS
	1-hour	188	0.100	-		-
Ozone	8-hour	147	0.075[b]	Same as Primary NAAQS		Same as Primary NAAQS
PM_{10}	24-hour	150[c]	-	Same as Primary NAAQS		Same as Primary NAAQS
$PM_{2.5}$	Annual	12.0[d]	-	15.0	-	Same as Secondary NAAQS
	24-hour	35[e]	-	Same as Primary NAAQS		Same as Primary NAAQS
SO_2	Annual	80[f]	-	-	-	Same as Primary NAAQS
	24-hour	365[f]	-	-	-	Same as Primary NAAQS
	3-hour	-	-	1,300	0.5	Same as Secondary NAAQS
	1-hour	195	0.075	-	-	Same as Primary NAAQS

Notes:

(a) Not to be exceeded more than once per year.

(b) The 2008 standard. The three-year average of the 4th highest daily maximum 8-hour average concentration over each year must not exceed the standard.

(c) Not to be exceeded more than once per year on average over three years.

(d) The three-year average of the weighted annual mean concentrations must not exceed the standard.

(e) The three-year average of the 98th percentile concentrations must not exceed the standard.

(f) The USEPA revoked the annual and 24-hour standards in the 2010 SO_2 rulemaking establishing the 1-hour standard and retaining the 3-hour secondary standard. However, the annual and 24-hour standards remain in effect until one year after an area is designated for the 2010 standard. The USEPA issued designations on July 25, 2013; therefore, the annual and 24-hour standards remain in effect until July 25, 2014.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project

Pollutant	Averaging Period	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	PSD SERs (tpy)	SILs ($\mu g/m^3$)	Monitoring De Minimis Concentrations ($\mu g/m^3$)
PM_{10}	24-hour	8[a]	30[a]	15[a]	5	10
$PM_{2.5}$	Annual	1	4	10 of $PM_{2.5}$	0.3	
				40 of SO_2	N/A	
				40 of NO_X[b]	N/A	
	24-hour	2	9		1.2	0[c]
NO_2	Annual	2.5	25	40 of NO_X	1	14
	1-hour	-[c]	-[c]		7.5[c]	
Ozone	8-hour	-	-	40 of VOC or NO_X	-	VOC or NO_X emissions increase > 100 tpy
CO	8-hour	-	-	100	500	575
	1-hour	-	-		2,000	-

Notes:

(a) In addition to PM_{10}, there is a PSD SER for Total Suspended Particulate (TSP) of 25 tpy.

(b) NO_X emissions regulated unless demonstrated not to be a $PM_{2.5}$ precursor. Ammonia and VOC emissions are presumed not to be precursors. See 73 *Federal Register* 28321 for additional details.

(c) PSD Increments, SIL, and Monitoring De Minimis Concentration level for the 1-hour NO_2 standard has not been finalized. However, an interim SIL of 7.5 µg/m3 for NO_2 was provided by the USEPA in a general guidance implementation memo dated June 28, 2010. The monitoring de minimis concentration for $PM_{2.5}$ was effectively set equal to zero due to the Circuit Court decision on January 22, 2013.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

NO_2 = nitrogen dioxide

NO_X = nitrogen oxide

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

USEPA = United States Environmental Protection Agency

VOC = volatile organic compounds.

3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS

For primary air pollutant compounds, i.e., pollutants directly emitted from emission sources, and secondary air pollutants (ozone, formed from the directly emitted pollutants NO_X and VOC), four monitoring stations surround Lake Charles. These are detailed in Table 4 along with the pollutants monitored at each site.

Table 4 Ambient Air Monitoring Stations near Lake Charles

Site	Distance and Direction from Project Site	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC	Ozone
Baton Rouge	130 miles to east	✓	✓	✓	✓	✓		✓
Lafayette	75 miles to east			✓	✓			✓
Carlyss	4.8 miles to northwest							✓
Lake Charles Lighthouse Lane	7.6 miles to north-northwest						✓	
Westlake	11 miles to north		✓		✓	✓	✓	✓
McNeese University	7 miles to northeast				✓			

Source: LDEQ n.d.
Key:
CO = carbon dioxide.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
SO_2 = sulfur dioxide.
VOC = volatile organic compounds.

Magnolia evaluated the distance, direction, and surroundings of each monitoring site to select the appropriate background monitor data sites. Magnolia proposes to use the Westlake monitor site for background data for NO_X, SO_2, and ozone since it is the closest monitoring site to the Project location where these pollutants are measured and is representative of the Project location. Magnolia proposes to use $PM_{2.5}$ data from the McNeese University site, which is the closest $PM_{2.5}$ monitoring station to the Project location. There are no stations in the Lake Charles vicinity that monitor for CO or PM_{10}; the closest site where PM_{10} is monitored is in Lafayette (approximately 75 miles to the east), and CO is monitored in Baton Rouge (approximately 130 miles to the east). These latter two sites are proposed as PM_{10} and CO background data sites. While relatively distant from the Project location and surrounded by urbanized land development, they likely represent typical PM_{10} and CO concentrations for an urban/developed land type setting similar to the Project location. Due to the central city location of the Baton Rouge CO monitor, a higher influence of vehicle emissions may tend to cause data from this station to be slightly conservative (higher) than the Project site. The appropriate statistical form

of the background concentration data will be obtained from either the LDEQ or the USEPA Airs database. Adjusted background procedures as described in the LDEQ guidance will not be used.

3.4 MODEL SELECTION

The USEPA's AERMOD, Version 13350 (issued December 16, 2013), will be the regulatory dispersion model used to estimate ambient impact concentrations of emissions from the Project sources. Regulatory default options as recommended in the USEPA's Guideline on Air Quality Models will be used in the modeling analysis. The regulatory default option in AERMOD includes the use of stack-tip downwash, incorporates the effects of elevated terrain, and includes the calms and missing data processing routines.

Preprocessing programs associated with AERMOD include AERMAP (version 11103), AERSURFACE (version 13016), AERMET (version 13350) and AERMINUTE (version 11325). These are the most recent versions available. If the USEPA issues updated versions prior to the start of input data preprocessing for the Project, Magnolia will use updated versions.

3.5 SOURCE CHARACTERIZATION

All proposed emission sources, including marine sources when stationary, will be modeled as point sources. The Project emission source inventory, heat input ratings and anticipated hours of operation are presented in Table 5. Magnolia is working with potential equipment vendors for the auxiliary boiler, thermal oxidizer, emergency use engines for the emergency generator and firewater pump, and for flares to develop final specifications and emission rates. Table 6 shows preliminary stack parameters for the Project emission sources as currently known. Draft emission rates for each source are shown in Appendix A; however, final source characteristics and maximum emission rates to be modeled will represent worst-case conditions and will be presented in the modeling report and permit application after the Best Available Control Technology (BACT) analysis has been completed.

Marine Emission Sources

LNG tankers that may call on the Project facility would range in cargo capacity from 125,000 m^3 up to 218,000 m^3 capacity. LNG barges would have a cargo capacity up to 15,000 m^3. In addition, an LNG carrier calling on Magnolia's loading facilities would require the use of tug boats (three tugs of up to 7,000 horsepower [hp] each) to assist the LNG carrier while transiting through the Calcasieu River and while docking and undocking. One tug (7,000 hp) would most likely be used to maneuver an LNG barge into and away from the loading dock. For LNG carriers, the assist tugs would be released once docking is completed. However, due to the short duration for loading an LNG barge, the tug may remain with the LNG barge during loading operations.

An LNG carrier's propulsions systems may consist of a steam boiler/turbo generator system or dual-fuel diesel electric (DFDE) drive systems. Future LNG carriers may also consist of dual-engine, dual-fuel direct drive systems. After the operational date of the Project facility, any type of LNG carrier currently in use may call on the Magnolia's loading facilities. For

purposes of illustrating modeling procedures for this protocol, a DFDE propulsion system LNG carrier with cargo capacity of 175,000 m^3 is discussed. Additional modeling scenarios for other LNG carrier propulsion types may also be modeled, depending on further information becoming available on the expected numbers and types of LNG carriers calling on Magnolia's loading facilities.

The Project is being designed with a single new docking berth to accommodate LNG carriers and LNG barges. However, only one LNG carrier or one barge would be able to load LNG at any given time since there would be only one set of loading arms available. Therefore, there would be no possibility for simultaneous loading into two vessels.

It is currently projected that, on average, up to two LNG carriers per week and up to two LNG barges per week would make port calls at the Project terminal when operating at full plant capacity. Using an average LNG carrier capacity of 175,000 m^3, approximately 104 LNG carriers could load LNG at the Magnolia LNG terminal. Using a barge capacity of 15,000 m^3, 104 barge loadings also could occur per calendar year.

Current projections of port call frequency are based on the maximum nominal LNG output of 8 mtpa and average LNG carrier cargo capacity of 175,000 m^3 and 15,000 m^3 barge capacity. The actual number of port calls per week will be determined by contracts that are subsequently executed and the specific ships and barges used. The maximum number of LNG carrier and LNG barge transits per year would also be affected by the USCG's determination as part of the Waterway Suitability Assessment (WSA) process. At this time, Magnolia projects that LNG barge port calls would not begin until after Train 2 is commissioned. The projected number of port calls for marine source modeling purposes is based on potential LNG plant output alone at full plant capacity and does not reflect anticipated customer requirements or results of the WSA process, which may result in less than maximum port calls. Thus, two LNG carrier loadings and two LNG barge loadings per week for 52 weeks per year will be modeled for assessment of annual impacts. Since a range of LNG carrier sizes could call on Magnolia throughout a calendar year, for annual average purposes, an average LNG carrier size is assumed to be 175,000 m^3.

An LNG carrier call on Magnolia's loading facilities would require the use of tug boats (three tugs of up to 7,000 hp each) to assist the LNG carrier while transiting the Calcasieu River and while docking and undocking. During docking and undocking, each tug boat's engine and the LNG carrier engine would operate at varying loads as necessary for maneuvering to or from the dock. Typically, docking and undocking requires approximately one hour each to complete. At the maximum LNG loading rate of 10,000 m^3/hour, it would take approximately 12.5 hours to load a 125,000-m^3 LNG carrier, up to 21.8 hours to load a 218,000-m^3 LNG carrier. During the loading period, it is anticipated that the LNG carrier would be operating in "hoteling" mode, with propulsion engines in a hot standby mode and generator set engine operation limited to a load necessary to meet the electrical load demand from the ship's systems while docked. Power for pumping LNG to the tanker would be provided by electric motor driven pumps located onshore.

Similar procedures would be used to maneuver barges into and away from the loading dock. One tug (7,000 hp) would most likely be used to maneuver the barge into and away from

the loading dock. During this period, the tug's engines would operate at varying loads as necessary for maneuvering to or from the dock. Once docked, the tug would remain on standby (in idle mode, approximately 10 percent engine load) while the barge is loaded. A 15,000-m^3 LNG barge could be loaded in approximately two hours.

An LNG carrier and an LNG barge cannot be loaded simultaneously; therefore, only one LNG carrier or one LNG barge can be docked in the loading berth at any given time. For short-term (i.e., 1-hour to 24-hour) emission rate purposes, the worst-case short-term emission rate scenario from marine sources is expected to be the LNG carrier in hoteling mode. The LNG carrier hoteling emission scenario will be further evaluated during the modeling study to include other LNG carrier propulsion systems that may have different emission rates to assess short-term ambient impacts in conjunction with the liquefaction facility's stationary source operation. In addition, if tug boats are required to remain on standby at the dock while the LNG carrier is being loaded, tug boat emissions will be included in the modeling analysis.

For assessment of annual NO_2, SO_2, and $PM_{2.5}$ NAAQS impacts, the annual emission rate will reflect the worst-case annual emissions from the potential LNG carrier loadings (considering each type of LNG carrier that may call on Magnolia) and 104 barge loadings per year. Emission rates used in modeling would be annual tons for an LNG carrier and LNG tug/barge, each divided by 8,760 hours per year.

Fuel type and blends used by the LNG carrier may be marine diesel and/or boil-off gas for both propulsion and generator set engines. Fuel use would vary depending on the type of propulsion system employed and presence or lack of an onboard boil-off gas compressor on the LNG carrier. LNG carrier emissions are governed by the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI of the International Maritime Organization (IMO); NO_X emission regulations are found in Regulation 13 and SO_X regulations are found in Regulation 14. Emissions for tug boats are controlled primarily through USEPA marine fuel and engine specifications. The IMO and the USEPA have established the North American Emission Control Area (NAECA) that is applicable to the entire coastlines of the United States and Canada. In calendar year 2015, all vessels operating within 200 nautical miles of the coast will be required to use fuel with a sulphur content less than 0.1 percent. The USEPA and the USCG have entered into a memorandum of understanding for enforcement of the fuel sulphur requirement in accordance with MARPOL Annex VI.

Equipment Description

Magnolia is currently evaluating emission source characteristics (e.g., stack height, diameter, exit temperature, and velocity) data for the existing LNG carrier and tug boat fleet that may be utilized on the Project. The data ultimately used in the modeling will be provided in the marine sources modeling report.

The stationary gas turbines for the Project will be aero-derivative units produced by General Electric, model PGT25+G4. Each gas turbine would combust only pipeline quality natural gas and would be equipped with dry-low emissions (DLE) and a waste heat recovery unit. Each unit's heat input rating is shown in Table 5.

Magnolia is currently in the process of obtaining proposals from potential auxiliary boiler vendors; therefore, a specific unit has not been selected at this time. The data presented in this protocol are preliminary and subject to change upon final vendor selection. However, the data presented are reasonable approximations of the performance characteristics of the boiler.

Table 5 Emission Source Equipment Inventory – Magnolia LNG Project

Equipment Type	Quantity On-Site	Heat Input Rating (MMBtu/hr)[(a)]	Expected Annual Hours of Operation
Gas Turbine	8	318.42	8,760
Auxiliary Boiler	4	96	8,760
CO_2 Vent/Thermal Oxidizer	4	20.2	8,760
Diesel Engine Firewater Pump	1	1.85	<100
Diesel Engine Emergency Generator	1	7.42	<100
Marine Flare	1	To Come	<100
Process Flare	1	To Come	<100

Note: (a) Based on higher heating value (HHV) of 1,043 Btu/scf.
Key:
Btu/scf = British thermal units per standard cubic foot
CO_2 = carbon dioxide.
MMBtu/hr = million British thermal units per hour.

Table 6 Preliminary Stack Parameter Values for Project Emission Sources

Emission Source	Stack Height (meters)	Stack Diameter (meters)	Exit Velocity (meters per second)	Exit Temperature (degrees Celsius)
Gas Turbine (each)	27	3.3	25	196
Auxiliary Boiler (each)	25	1.2	~15	149
CO_2 Vent/Thermal Oxidizer (each)	23	0.3	TBD	TBD
Cryogenic Flare	33	note 1	20	1,000
Process Flare	33	note 1	20	1,000
Emergency Generator Engine	TBD	TBD	TBD	TBD
Firewater Pump Engine	TBD	TBD	TBD	TBD

Notes:
1) Effective stack diameter to be based on calculation procedure contained in section 5.9.4 of LDEQ 2006 modeling guidance which relates resulting stack diameter to total heat release of gas being flared.
Key:
CO_2 = carbon dioxide
TBD = to be determined

The auxiliary boilers in each liquefaction train would combust a mixture of high British thermal unit (Btu) (feed gas and rich gas) and low Btu (holding and ship loading) fuel using low NO_X burners. The boiler efficiency would be approximately 84 percent. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has not been developed. For the preliminary potential to emit estimate, it is assumed the composition of the fuel gas is primarily feed gas with the waste gas stream from the carbon dioxide removal system. Blending in rich gas and low Btu gas would alter the potential to emit slightly, estimated as varying by no more than 5 to 10 percent. The fuel gas stream burned in the auxiliary boiler may also contain trace amounts of benzene, toluene, ethylbenzene, and xylene (BTEX) from the carbon dioxide removal system. The estimated destruction efficiency for these hazardous air pollutants (HAPs) in the combustion process is 99.99 percent.

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. Contaminated CO_2 (containing BTEX) would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement would allow the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation, resulting in a NO_X concentration of approximately 40 parts per million by dry volume at 3 percent oxygen. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Other necessary control devices and programming would be provided to ensure that the system would start and operate safely according to National Fire Protection Association 85/86 guidelines. The thermal oxidizer vendor has not been selected at this time.

The marine and process flare would not be used during normal operation; however, a small pilot light would be continuously lit should flaring be needed. Flaring would not be used during normal operation because the boil-off-gas generated from the LNG tank would be used as fuel gas in the auxiliary boiler. However, when maintenance is required, process lines may need to be manually vented and purged. There may also be occasions of automated venting from Pressure Relief Valves, Process Shutdowns, and Emergency Shutdown. During these events, flaring will be necessary. Magnolia is developing an estimate of the frequency of flaring that will be included in the final modeling protocol. Modeling guidance for flares from Section 5.9.4 of the LDEQ modeling guidance will be used if flares are included in the worst-case modeling condition.

Vendors have not been selected for the emergency generator set or the diesel firewater pump.

3.6 EFFECTS OF NEARBY FACILITIES

Effects of nearby facilities will not be included in the preliminary dispersion modeling analysis for comparison to the SILs. If the preliminary dispersion modeling analysis shows significant impacts, an additional protocol will be submitted for the refined analysis that includes contributions from nearby facilities for comparison to PSD increment consumption.

4 AERMOD MODELING OPTIONS

4.1 BUILDING DOWNWASH

Building downwash effects will be considered in the modeling analysis. Structures and buildings will be included in the analysis when the distance between modeled stacks and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. The Building Profile Input Program with Prime (BPIP-PRIME) will be used to calculate direction-specific building dimensions and good engineering practice stack heights. AERMOD uses the output from BPIP-PRIME to calculate building downwash effects.

Due to the compact footprint of each liquefaction train, each train will be considered as a solid building for input to BPIP-PRIME. Each liquefaction train has a maximum dimension of approximately 166 meters (545 feet) and minimum dimension of 44 meters (144 feet).

For modeling involving an LNG carrier, the dimensions of the vessel and any significant above-deck structure (e.g., the accommodation block typically on the stern) will be input to the model for evaluation of structure downwash. The tug/LNG barge combination does not present a significant obstruction to flow and thus will not be evaluated for building downwash.

4.2 TERRAIN

The terrain surrounding the proposed Project location up to 50 kilometers in any direction is best described as flat. A preliminary evaluation of terrain heights indicates most terrain elevations are between 0 feet and 20 feet in a 50-kilometer radius; there is a slight rise in elevation to the northwest with terrain reaching 40 to 50 feet at a distance of approximately 35 to 40 kilometers away. According to section 5.7 of the LDEQ Air Quality Modeling Procedures, requirements to consider terrain elevations are determined on a case-by-case basis. For the Project location in the Southwest Regional office region, the LDEQ typically does not require use of terrain data in dispersion modeling. However, after discussion with the LDEQ regarding implementing terrain data in flat terrain areas, Magnolia proposes to use the AERMOD Terrain Preprocessor (AERMAP Version 11103) to assign terrain elevations of source, building, and receptor locations. U.S. Geological Survey (USGS) 7.5-minute digital elevation models (DEMs) would be used for processing in AERMAP. The Project datum would be in North American Datum of 1983-Universal Transverse Mercator coordinates.

4.3 METEOROLOGICAL DATA

AERMOD will be run with surface meteorological data and upper air data from the Lake Charles Regional Airport. The airport is approximately 4.6 miles (7.5 kilometers) east-northeast of the Project site. Surface observation data will be obtained from the National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Database. Upper air data will be obtained from the NOAA Earth System Research Laboratory radiosonde observation database. A five-year dataset will be used, encompassing the period 2008 through 2012. If 2013 data are

available for upper air and surface datasets, the five-year dataset will comprise years 2009 through 2013.

The processing steps to be used include determining land surface characteristics followed by processing of the land surface characteristics; surface and upper air meteorological data. The USEPA AERSURFACE program (version 13016) will be used to determine the surface characteristics surrounding the Project site. AERSURFACE processes land cover data to determine the surface characteristics for use in AERMET. AERSURFACE uses a 1-kilometer radius surrounding the site to determine surface roughness values for each direction sector, and a 10-by-10-kilometer area to determine the mid-day albedo and daytime Bowen Ratio. AERSURFACE will be run for month-specific surface characterization. The AERMET (Version 13350) pre-processor will then be used to prepare meteorological data for use in AERMOD. Output from AERSURFACE will be input to AERMET along with surface and upper air meteorological observation data. Guidance provided in the most recent AERMOD Implementation Guide (USEPA 2009) will be followed.

Surface wind data sets will consist of automatic surface observing system (ASOS) 1-minute wind data from the Lake Charles Regional airport. These data sets will be processed using the AERMINUTE data pre-processor program for subsequent use in Stage 2 of AERMET data processing.

4.4 RECEPTORS

Impacts will be analyzed at receptors placed along and beyond the fence line of the Project site. Guidance provided by the USEPA describing locations considered as ambient air will be followed. In general, the guidance states that any property owned by the Project within a fenced in area (or area with public access controlled by other means) is not considered ambient air; locations outside of fenced-in locations owned by the Project are considered ambient air, including over-water locations.

The initial receptor grid will be established using a Cartesian grid at the following intervals:

- Along fence line: 100-meter spacing.
- Fence line to 1 kilometer beyond fence line: 100-meter spacing.
- From 1 kilometer to 5 kilometers beyond fence line: 500-meter spacing.
- From 5 kilometers to 10 kilometers beyond fence line: 1-kilometer spacing.

If the initial modeling indicates ambient concentrations remain above the applicable SIL beyond 10 kilometers, the receptor grid will be extended to determine the full extent of the area of influence, not to exceed 50 kilometers (the geographic/dispersion limit of the model) from the Project fence line. SILs are defined by the USEPA as ambient concentrations of air pollutants above which the potential for a significant air quality impact is deemed possible. It follows that if modeled ambient concentrations of air pollutants are below a SIL, a significant air quality impact is not likely and no further modeling is required. If the maximum concentration occurs beyond 1 kilometer of the fence line, then an additional receptor grid with 100-meter spacing

will be set up, centered on the receptor with the maximum impact to ensure the maximum impact is identified. Receptor elevations will be determined using AERMAP as discussed in Section 4.2.

The Mossville environmental justice community is located approximately 7 miles (11.3 kilometers) north of the Project site. The initial receptor grid outlined above would extend to 6.2 miles (10 kilometers) from the Project site. As noted in the preceding paragraph, if modeled impacts are above the applicable SIL at 6.2 miles (10 kilometers), the receptor grid would be extended so that ambient concentrations at receptors beyond 6.2 miles (10 kilometers), including the Mossville area, will be determined. Discrete (i.e., individual) receptors will be placed in the Mossville community to supplement the extended grid.

4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS

Emissions from a combustion source are primarily composed of two compounds, nitrogen oxide (NO) and nitrogen dioxide (NO_2), that are added together to determine total NO_X. The primary component of NO_X in the stack is NO. However, the NAAQS for this class of compounds has been established for NO_2 since NO_2 is the photochemically reactive form of NO_X that participates in ozone formation.

The USEPA has established a three tier procedure for determining the quantity of NOx emitted from an emission source that ultimately converts to NO_2 as described in the USEPA Guideline on Air Quality Models. Although the procedure was originally established to address the former annual NO_2 NAAQS, the procedures are still considered technically appropriate for the short-term NO_2 NAAQS. The tiered approach is intended to act as a screening procedure, with Tier 1 providing the most conservative result. Tiers 2 and 3 are used if unacceptable results are realized from Tier 1.

In Tier 1, full conversion of NO_X to NO_2 is assumed in modeling. If the NAAQS for NO_2 is exceeded, then the refined technique found in Tier 2 is applied.

In Tier 2, the Tier 1 1-hour modeled results will be multiplied by a NO_2 to NO_X ambient equilibrium ratio of 0.8 as recommended by the LDEQ. As in Tier 1, if the modeled results show an exceedance of the NAAQS, Tier 3 is applied.

Tier 3 consists of applying one of two non-default techniques available in the latest version of AERMOD that account for the atmospheric chemistry relationship between the conversion of NO_X to NO_2 and ambient ozone concentrations. Use of Tier 3 requires review by the USEPA as well as the LDEQ. Both techniques are fundamentally based on the limitation of NO_X to NO_2 conversion by the ambient ozone concentration and in-stack NO_X conditions. The Ozone Limiting Method (OLM) procedure applies a series of steps to determine the amount of NO_X that ultimately converts to NO_2 based on the amount of ozone present in the atmosphere. Conversion of NO_X to NO_2 is "limited" if the modeled NO_X concentration is greater than the ambient ozone concentration. The second ozone method under Tier 3 is the Plume Volume Molar Ratio Method (PVMRM). The PVMRM method takes into account more detailed information regarding the atmospheric chemistry processes in the plume resulting in conversion

of NO_X to NO_2. For both Tier 3 methods, a value for the ambient ozone concentration is required.

For this Project, the modeling analysis will apply each tier when modeling NO_2 in sequence, as necessary to demonstrate compliance with the NO_2 NAAQS. If Tier 3 becomes necessary, Magnolia will provide a supplement to this protocol to address data assumptions for the Tier 3 methodology. Proposed data to be discussed would include:

- Background ozone concentration;
- NO_2 to NO_X equilibrium ratio; and
- In-stack NO_2 to NO_X ratio for each modeled stationary source emitting NO_X. In-stack NO_2 to NO_X ratios are not available for marine emission sources.

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS

5.1 CLASS I

In addition to the comparison against ambient air quality standards for Class II modeling, an analysis of air quality impacts to Class I areas must also be assessed. Class I areas include locations under the jurisdiction of the United States Fish and Wildlife Service, United States Forest Service, and the National Park Service. The Class I designation has also been given to specific Native American lands that have been determined to require special treatment for air quality purposes. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, distances greater than 300 kilometers between an emission source and a Class I area precludes the need for further Class I air quality analyses. For a source to Class I distance greater than 400 kilometers, the FLAG screening test (Q/d) is not required. Therefore, due to the separation distance of greater than 400 kilometers, a Class I air quality screening analysis and refined impact assessment will not be required.

5.2 ADDITIONAL IMPACT ANALYSIS

As part of its permit application and stationary source modeling analysis for LDEQ, Magnolia will prepare an additional impact analysis following the guidelines in Chapter D of the USEPA New Source Review Workshop Manual (USEPA 1990) to address growth and associated ambient air quality impacts, soils and vegetation impacts and visibility impairment. The growth analysis will consider the Project's potential impact and emissions associated with growth of industrial, commercial and residential sectors as a result of the Project. The soils and vegetation assessment will consider the modeled ambient concentration resulting from the Project in comparison to secondary NAAQS that have been established for the purpose of protecting plants and animals from harm due to air quality. The visibility impairment analysis will consist of a determination of the visual quality in the area and an initial screening-level assessment of the possibility of visibility impairment. If necessary, a more in-depth analysis following procedures in the USEPA's Workbook for Plume Visual Impact Screening and Analysis (USEPA 1992) would be performed if initial screening indicated a potential impact.

6 REPORTING OF RESULTS

The air quality modeling analysis will be documented in a report that includes a summary narrative and a tabulation of the model results to demonstrate compliance with the applicable ambient air quality standards and other thresholds. The report will include the following elements:

- Detailed description of the proposed activity and emission sources with specific parameters used in the analysis including emission rates, stack heights, stack diameters, temperatures, exit velocities, and nearby building dimensions;
- Facility plot plan showing the location of emission sources, facility buildings, fence line corners, and terrain characteristics;
- Map (i.e., USGS with 1:24,000 scale) showing the facility location and receptors used in the analysis;
- Description of the model(s) selected and rationale for selection;
- Description of the site topography and receptor grids used in the analysis;
- Description of meteorological data;
- Technical support documentation for any assumptions made in the modeling analysis which deviate from the stated guidance; and
- Summary of model predictions showing comparison to applicable ambient air quality standards.

Digital copies of relevant model files will be included with the report, such as, but not limited to:

- Facility plot plan (in geo-referenced digital format);
- Meteorological files (.SFC and .PFL);
- Terrain files (USGS DEM files);
- Geo-referenced maps;
- Files related to BPIP-PRIME runs; and
- AERMOD model generated input and output files.

Reports and applicable digital files will be submitted to the FERC.

7 REFERENCES

Louisiana Department of Environmental Quality (LDEQ). n.d. LDEQ webpage: Southwest Air Monitoring Sites. http://www.deq.louisiana.gov/portal/tabid/2478/Default.aspx. Accessed December 3, 2013.

———. 2006. Air Quality Modeling Procedures. LDEQ Air Quality Assessment Division. August 2006.

United States Environmental Protection Agency (USEPA). 1990. New Source Review Workshop Manual – Draft, Prevention of Significant Deterioration and Nonattainment Area Permitting. New Source Review Section, Air Quality Management Division.

———. 1992. Workbook for Plume Visual Impact Screening and Analysis (Revised). http://www.epa.gov/ttn/scram/userg/screen/WB4PlumeVisualOCR.pdf. Accessed December 9, 2013.

———. 2005. Guideline on Air Quality Models. 40 CFR 51, Appendix W. November 2005.

———. 2010a. EPA Guidance Concerning the Implementation of the 1-Hour NO_2 NAAQS for the Prevention of Significant Deterioration Program. Memorandum dated June 29, 2010 from Stephen Page (USEPA) to Regional Air Division Directors.

———. 2010b. Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS. Memorandum dated March 23, 2010, from Stephen Page (USEPA) to USEPA Regional Modeling Contacts and other addressees.

———. 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard. Memorandum dated March 1, 2011, from Tyler Fox (USEPA) to Regional Air Division Directors.

———. 2013a. Draft Guidance for $PM_{2.5}$ Permit Modeling. Memorandum dated March 4, 2013, from Stephen Page (Director, Office of Air Quality Planning and Standards to various addresses (as listed in memorandum).

———. 2013b. Circuit Court Decision on PM2.5 Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers. March 4, 2013. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards.

This page left blank intentionally.

Appendix A
Preliminary Operational Emission Estimates

This page left blank intentionally.

Table A1 Preliminary Potential Operation Emissions (tons per year) – Magnolia LNG								
Emission Source	NO_X	CO	SO2	PM10	PM2.5	VOC	HAPs	CO2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator (1)	1.5	3	0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump (1)	0.7	1.5	0	0.01	0.01	0.4	0.06	125
Total	1,119	813	33	90	90	57	16	1,559,837

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

Parameter		Units	Value
Fuel Lower Heating Value (LHV)[1]		Btu/scf	935.1
Fuel Higher Heating Value (HHV) [1]		Btu/scf	1036.4

Parameter	Units	Turbine 1	Number of Turbines	Total for Eight Turbines
Hourly Fuel Flow (LHV) - Maximum[2]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (LHV) - Average[3]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (HHV) - Maximum[4]	MMBtu/hr	318.42	8	2,547
Hourly Fuel Flow (HHV) - Average[4]	MMBtu/hr	318.42	8	2,547
Annual Operation @ 100% Load	hr/yr	8760	8	70,080
Maximum Annual Fuel Flow (LHV)[5]	MMBtu/yr	2,516,748	8	20,133,984
Maximum Annual Fuel Flow (HHV)[6]	MMBtu/yr	2,789,389	8	22,315,112
Maximum Annual Fuel Flow (volume)[6]	MMscf/yr	2,690	8	21,520

Pollutant Type	Pollutant	LHV Emission Factor (lb/MMBtu)	HHV Emission Factor[7,8,9] (lb/MMBtu)	Each Turbine		Eight Turbines	
				Maximum Hourly Emission Rate (lb/hr)	Maximum Annual Emissions (tpy)	Annual Emissions (tpy)	
Criteria	NO_X			29.00	127.02	1016.2	
	CO			18.24	79.89	639.1	
	VOC			1.28	5.61	44.9	
	PM	-	0.0066	2.10	9.20	73.6	
	PM_{10}	-	0.0066	2.10	9.20	73.6	
	$PM_{2.5}$	-	0.0066	2.10	9.20	73.6	
	SO_2	-	0.0028	0.90	3.93	31.5	
HAPs	Acetaldehyde	-	0.000040	0.013	0.056	0.4	
	Acrolein	-	0.0000064	0.002	0.009	0.1	
	Benzene	-	0.000012	0.004	0.017	0.1	
	Ethylbenzene	-	0.000032	0.010	0.045	0.4	
	Formaldehyde	-	0.00071	0.226	0.990	7.9	
	Toluene	-	0.00013	0.041	0.181	1.5	
	Xylenes	-	0.000064	0.020	0.089	0.7	
	Total HAPs	-	**-**	**0.3166**	**1.387**	**11.095**	
Greenhouse Gas	CO_2			37218	163,015	1304118.7	
	N_2O	-	0.003	0.96	4.18	33.5	CO_2e Multiplier
	CH_4	0.028	0.0255	5.13	22.46	179.7	
Greenhouse Gas (CO_2e)	CO_2	-	-	37,218	163,015	1,304,119	1
	N_2O	-	-	296	1,297	10,377	310
	CH_4	-	-	108	472	3,773	21
	Total GHGs	-	**-**	**37,622**	**164,784**	**1,318,269**	

Notes:
1. Data from GE PGT25+G4 DLE Expected Emissions.xlsx sheet (based on Fuel Number 800-41 Magnolia).
2. Data from GE PGT25+G4 Turbine Specification Sheets. Fuel flow based on inlet temperature chilled to 15.0 ^oC dry bulb.
3. Inlet cooling to be used to maintain inlet temperature, therefore little variation between hourly maximum and annual average.
4. Calculated from hourly fuel flow (LHV basis) and ratio of HHV to LHV.
5. Maximum annual fuel flow for each turbine calculated by multiplying maximum hourly fuel (LHV) by annual operation @ 100% load.
6. Calculated from maximum annual fuel flow (LHV).
7. NO_X, CO, VOC, and CH_4 emission factors from GE PGT25+G4 Turbine Specification Sheets.
8. CO_2 emission factor from GE PGT25+G4 DLE Expected Emissions.xlsx.
9. Emissions factors from United States Environmental Protection Agency (EPA). 2000. AP 42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensable and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensable and filterable fractions). SO_2 emission factor based on sulfur content of 0.003%.

Table A3
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		1000	kW
		1341	
Engine Fuel Flow Rate (HHV)[1]		5,534	Btu/hp-hr
		7.42	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	5.91	1.5	
	CO	-	4.0	11.8	3.0	
	VOC	-	1.0	2.96	0.7	
	PM	0.00999	-	0.073	0.018	
	PM_{10}	0.00999	-	0.073	0.018	
	$PM_{2.5}$	0.00999	-	0.073	0.018	
	SO_2	0.000588	-	0.0043	0.0011	
HAPs	Acetaldehyde	0.00836	-	0.061	0.015	
	Acrolein	0.00514	-	0.038	0.009	
	Benzene	0.000440	-	0.0032	0.0008	
	Ethylbenzene	0.0000397	-	0.00029	0.000072	
	Hexane	0.00111	-	0.008	0.0020	
	Formaldehyde	0.0528	-	0.39	0.10	
	Toluene	0.000408	-	0.0030	0.00074	
	Xylenes	0.000184	-	0.0013	0.00034	
	Total HAPs	**-**	**-**	**0.50**	**0.13**	
Greenhouse Gas	CO_2	110	-	803	201	CO_2e
	CH_4	1.25	-	9	2.3	Multiplier
Greenhouse	CO_2	-	**-**	803	201	1
Gas	CH_4	-	**-**	192	48	21
(CO_2e)	**Total GHGs**	**-**	**-**	**995**	**249**	

Notes:

1. Estimated based on typical unit.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A4
Emissions for Fire Water Pump Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		500	kW
		670	
Engine Fuel Flow Rate (HHV)[1]		2,767	Btu/hp-hr
		1.85	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	2.95	0.7	
	CO	-	4.0	5.9	1.5	
	VOC	-	1.0	1.48	0.4	
	PM	0.00999	-	0.018	0.005	
	PM_{10}	0.00999	-	0.018	0.005	
	$PM_{2.5}$	0.00999	-	0.018	0.005	
	SO_2	0.000588	-	0.0011	0.0003	
HAPs	Acetaldehyde	0.00836	-	0.015	0.004	
	Acrolein	0.00514	-	0.009	0.002	
	Benzene	0.000440	-	0.0008	0.0002	
	Ethylbenzene	0.0000397	-	0.00007	0.000018	
	Hexane	0.00111	-	0.002	0.0005	
	Formaldehyde	0.0528	-	0.10	0.02	
	Toluene	0.000408	-	0.0007	0.00019	
	Xylenes	0.000184	-	0.0003	0.00008	
	Total HAPs	**-**	**-**	**0.12**	**0.03**	
Greenhouse Gas	CO_2	110	-	201	50	CO_2e
	CH_4	1.25	-	2	0.6	Multiplier
Greenhouse	CO_2	-	-	201	50	1
Gas	CH_4	-	-	48	12	21
(CO_2e)	**Total GHGs**	**-**	**-**	**249**	**62**	

Notes:
1. Estimate.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensible and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A5
Emissions for Thermal Oxidizer
Magnolia LNG

Parameter	Value	Units
Fuel Flow Rate (HHV)[1]	20.23	MMBtu/hr
Higher Heating Value (HHV)[2]	1043	Btu/scf
Maximum Yearly Operation	8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMBtu)	Maximum Hourly Emission Rate (each)[4] (lb/hr)	Annual Emissions for Four Units (tpy)	
Criteria	NO_X	50.00	0.0501	1.01	17.8	
	CO	84.000	0.0842	1.70	29.8	
	VOC	5.5000	0.0055	0.11	2.0	
	PM	7.6	0.0076	0.15	2.7	
	PM_{10}	7.6	0.0076	0.15	2.7	
	$PM_{2.5}$	7.6	0.0076	0.15	2.7	
	SO_2	0.600000	0.0006	0.01	0.2	
HAPs	2-methylnapthalene	0.000024	0.000000	0.0000	0.000	
	Anthracene	0.000002	0.000000	0.0000	0.000	
	Benzene	0.0021	0.000002	0.0083	0.145	
	Dichlorobenzene	0.0012	0.000001	0.0000	0.000	
	Hexane	1.8000	0.001804	0.0365	0.640	
	Formaldehyde	0.0750	0.000075	0.0015	0.027	
	Napthalene	0.0006	0.000001	0.0000	0.000	
	Toluene	0.0034	0.000003	0.0244	0.427	
	Xylene	0.0000	0.000000	0.0280	0.490	
	Total HAPs	**-**		**0.07**	**1.24**	
Greenhouse Gas	CO_2	120000	120.2999	2433.67	42,637.840	CO_2e
	N2O	0.64	0.0006	0.01	0.227	
	CH_4	2.30	0.0023	0.05	0.817	Multiplier
Greenhouse	CO_2	-		2,434	42,638	1
	N2O			4	70	310
Gas	CH_4	-		1	17	21
(CO_2e)	**Total GHGs**	**-**		**2,439**	**42,725**	

Notes:
1. Estimate from preliminary design data from Magnolia LNG.
2. Based on HHV for feed gas for project used for aux boiler and thermal oxidizer spec.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A6: Estimated BTEX Destruction Efficiency

	Aux. Boiler Fuel			Thermal Oxidiser		
Destruction Efficiency		**99.99%**			**99.00%**	
	INLET	**OUTLET**		**INLET**	**OUTLET**	
	Mass Flow (kg/hr)	**Mass Flow, t/yr**		**Mass Flow (kg/hr)**	**Mass Flow, t/yr**	
CO2	0.005			10502.0366		
Nitrogen	0.014			0.0000		
Methane	73.511			5.4082		
Ethane	75.195			0.5032		
Propane	79.130			0.1054		
i-Butane	67.528			0.0000		
n-Butane	103.827			0.0000		
i-Pentane	199.821			0.0000		
n-Pentane	347.825			0.0000		
n-Hexane	534.789		lb/hr	0.0000		lb/hr
Benzene	137.574	0.121	0.030329	0.3735	0.033	0.008234
Cyclohexane	50.163	0.044	0.011059	0.0000		
n-Heptane	227.860			0.0000		
Toluene	41.926	0.037	0.009243	1.1015	0.096	0.024283
n-Octane	25.997			0.0000		
p-Xylene	16.108	0.014	0.003551	1.2691	0.111	0.027979
E-Benzene	16.108	0.014	0.003551	0.0000		
H2S	0.001			1.9553		
Ammonia	0.000			0.0000		
H2O	0.000			0.0000		
Total	**1997.382**	**0.229**		**10512.753**	**0.240**	
For 4 Trains		0.92			0.96	
Total MLNG Plant		**1.88**	**t/yr**			

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate [1]		92,130	ft3/hr
		96.00	MMBtu/hr
Higher Heating Value (HHV)[1]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMscf)	Maximum Hourly Emission Rate[4] (lb/hr)	Annual Emissions (tpy)	Annual Emissions Four Units (tpy)	
Criteria	NO_X	50	51.1275	4.71	20.6	82.53	
	CO	84	85.8941	7.91	34.7	138.64	
	VOC	5.5	5.6240	0.52	2.3	9.08	
	PM	7.6	7.7714	0.72	3.136	12.54	
	PM_{10}	7.6	7.7714	0.72	3.136	12.54	
	$PM_{2.5}$	7.6	7.7714	0.72	3.136	12.54	
	SO_2	0.60	0.6135	0.06	0.2476	0.99	
HAPs	2-methylnapthalene	0.000024	0.0000	0.00000	0.000	0.00	
	Anthracene	0.000002	0.0000	0.00000	0.000	0.00	
	Benzene	0.0021	0.0021	0.03053	0.1337	0.53	
	Cyclohexane	0.0000	0.0000	0.01106	0.0484	0.19	
	Dichlorobenzene	0.0012	0.0012	0.00011	0.000495	0.00	
	Ethylbenzene	0.0000	0.0000	0.00355	0.0156	0.06	
	Hexane	1.8000	1.8406	0.16957	0.7427	2.97	
	Formaldehyde	0.0750	0.0767	0.00707	0.03	0.12	
	Napthalene	0.0006	0.0006	0.00006	0.00	0.00	
	Toluene	0.0034	0.0035	0.00032	0.00140	0.01	
	Xylene	0.0000	0.0000	0.00355	0.0156	0.06	
	Total HAPs			**0.22**	**0.99**	3.96	
Greenhouse Gas	CO_2	120000	122705.8824	11304.89	49,515	198,062	
	N_2O	0.64	0.6544	0.06	0	1	CO_2e
	CH_4	2.30	2.3519	0.22	1	4	Multiplier
Greenhouse	CO_2			11,305	49,515	198,062	1
	N_2O			19	82	327	310
Gas	CH_4			5	20	80	21
(CO_2e)	**Total GHGs**			**11,328**	**49,617**	198,469	

Notes:
1. From Babcock & Wilcox P55-6356_BW_Budget_R01.pdf Oct 15 2013.

2. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
3. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by ratio of actual fuel heat value divided by 1020.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A8
Natural Gas Composition Data
Magnolia LNG

Component	Molar (Volume) Fraction[1] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Nitrogen	1.014	28.01	0.284	1.692
Carbon Dioxide	0.01	44.01	0.003	0.02
Methane	95.60	16.04	15.34	91.3
Ethane	2.56	30.07	0.770	4.58
Propane	0.32	44.10	0.143	0.852
I-Butane	0.091	58.12	0.053	0.316
N-Butane	0.091	58.12	0.053	0.316
I-Pentane	0.0811	72.15	0.059	0.348
N-Pentane	0.0811	72.15	0.059	0.348
Hexanes	0.035	95.96	0.033	0.197
Total	**99.9**	**-**	**16.79**	**100.0**

HAP Component	Molar (Volume) Fraction[2] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Benzene	0.00310	78.114	0.00242	0.0144
Ethylbenzene	0.00002	106.167	0.00002	0.000109
n-Hexane	0.00100	86.177	0.00086	0.0051
Toluene	0.00100	92.141	0.00092	0.00549
Xylenes	0.00100	106.167	0.00106	0.00632
Total HAPs	**0.0061**	-	-	**0.0315**

Component	Weight Fraction in Natural Gas (wgt %)	Weight Fraction in TOC (wgt %)
TOC	98.3	100
Methane	91.3	92.9
VOC	2.38	2.42
Benzene	0.0144	0.0147
Ethylbenzene	0.000109	0.000111
n-Hexane	0.005	0.005
Toluene	0.00549	0.00558
Xylenes	0.00632	0.00643
Total HAPs	0.0315	0.0320

Notes:

1. Based on Fuel Number 800-41 Magnolia provided by GE for PGT25+G4 DLE emissions.
2. Component split based on GRI GLY-Calc V4.0 lumped C6+ gas analysis multipliers for the Natural Gas Transmission Industry Segment.

Table A9 - LNG Vessel Operational Emissions - Revised

SLOW SPEED DIESEL without reliquefaction

		Nat Gas	Units	Tugs Diesel	Units	Oil	Units
Emission	NOx	1.3	g/kW-hr	13.32	g/kW-hr	17	g/kW-hr
Factors	CO	1.1	g/kW-hr	1.69	g/kW-hr	5.8	g/kW-hr
	VOC	0.5	g/kW-hr	0.61	g/kW-hr	0.58	g/kW-hr
	PM	0.05	g/kW-hr	0.51	g/kW-hr	0.5	g/kW-hr
	(Tug factor based on 1%S marine diesel) SO2	0.05	g/kW-hr	3.92	g/kW-hr	12.9	g/kW-hr
	CO2	420	g/kW-hr	721.3	g/kW-hr	580	g/kW-hr

Assumptions

LNG Carrier speed at rated power = 19 knots

Efs from Wartsila 50DF and American Shipping Bureau

95% Nat Gas/5% HFO used on inbound and outbound trip in propulsion engines - revised based on info from MAN diesel regarding ME-GI propulsion

99% Nat Gas/1% MDO used in generator set engine for Hoteling

0.1 Estimated effect of Nonroad fuel requirement on sulfur content after June 1, 2007 (90% reduction).

Annual Carrier dockings (175K m3 vessel)	104	berthings/yr	berthings based on 2/week as stated in RR1
Annual Barge dockings (15K m3 barge)	104	berthings/yr	berthings based on 2/week as stated in RR1

Total Power LNG Carrier	30,575	bhp	22,800	kW	LNG power based on typical 175K m3 DFDE LNG carrier
Total Power (3 assist Tugs)	21,000	bhp	15,698		
Total Power (2 assist Tugs)	14,000	bhp	10,465	kW	
Total Power (1 assist Tug)	7,000	bhp	5,233	kW	

LNG Carrier and Assist Tugs

Vessel	Activity	Duration (hr)	Engine Load (%)	Total Engine Power (bhp)	Total Engine Power (kW)	Natural Gas Flow (MMBtu/hr)	Activity Emissions (lb) NOx	CO	VOC	PM	SO2	CO2	Annual Emissions (tpy) NOx	CO	VOC	PM	SO2	CO2
LNG Carrier	10.4 n. miles out to shore @ 12 knots	0.9	80%	24460	18240	178.6	73	47	18	3	24	14973	3.8	2.43	0.92	0.13	1.26	778.61
Inbound	Shore up Calcasieu to Magnolia 22 n. miles @ 5 knots	4.4	20%	6115	4560	44.6	92	59	22	3	31	18932	4.8	3.07	1.16	0.17	1.59	984.45
95%Natural Gas	Maneuvering near dock ships power	1.0	10%	3057.5	2280	22.3	10	7	3	0	3	2151	0.5	0.35	0.132	0.02	0.18	111.87
5% Residual oil	**Subtotal**	**6.3**	-	-	-	-	**176**	**112**	**42**	**6**	**58**	**36056**	**9.1**	**5.8**	**2.21**	**0.3**	**3.0**	**1875**
	Hoteling while loading	**18.0**	10%	3057.5	2280	22.3	132	104	45	5	16	38145	6.9	5.40	2.356	0.26	0.84	1983.53
LNG Carrier	Maneuvering away from dock ships power	1.0	10%	3057.5	2280	22.3	10	7	3	0	3	2151	0.5	0.35	0.132	0.02	0.18	111.87
Outbound	Transit from dock to Gulf shore line @avg 5 kts	4.4	20%	6115	4560	44.6	92	59	22	3	31	18932	4.8	3.07	1.16	0.17	1.59	984.45
95%Natural Gas	Shore to 10.4 n. miles out @ 12 knots	0.9	80%	24460	18240	178.6	75	48	18	3	25	15490	3.9	2.51	0.95	0.14	1.30	805.46
5% Residual oil	**Subtotal**	**6.3**					**178**	**114**	**43**	**6**	**59**	**36572**	**9.3**	**5.9**	**2.24**	**0.3**	**3.1**	**1901.8**
	1 tug transit from port to meet Carrier 3 n. mi. offshore (25 n. miles @ 10 kts)	2.5	80%	5600	4186	n/a	307	39	14	12	90	16641	16	2	1	1	0.470	865
Tug Boats	1 tug transit alongside Carrier to Magnolia (25 n. mi. at 6 kts)	4.5	50%	3500	2616	n/a	346	44	16	13	136.1	18721.4	18.0	2.28	0.82	0.69	0.708	973.511
	2 addnl tugs transit from port to meet Carrier 3.0 n.mi. from Magnolia (3 n. mi. @ 10 knts)	0.3	80%	11200	8372	n/a	74	9	3	3	22	3993.9	4	0	0	0	0.113	208
	2 addnl tugs transit alongside Carrier to Magnolia (3.0 n.mi. at 6 kts.)	0.5	50%	7000	5233	n/a	77	10	4	3	23	4160.3	4	1	0	0	0.118	216
Diesel	3 tugs assist carrier dock at Magnolia, release after docking	1.0	90%	18900	14128	n/a	415	53	19	16	163.3	22465.6	21.6	2.74	0.99	0.83	0.849	1168
	3 tugs full power push/tow away from dock	1.0	90%	18900	14128	n/a	415	53	19	16	163.3	22465.6	21.6	2.74	0.99	0.83	0.849	1168
	2 tugs transit alongside Carrier to 3.0 n. mi. from Magnolia and release (3 n. mi. at 6 kts)	0.5	50%	7000	5233	n/a	77	10	4	3	30.2	4160.3	4.0	0.51	0.18	0.15	0.157	216.336
	2 tugs transit back to port from release of Carrierat 3 n. mi. from Magnolia (3 n.mi. at 10 kts)	0.3	80%	11200	8372	n/a	74	9	3	3	22	3993.9	4	0	0	0	0.113	208
	1 tug transit alongside Carrier to release 3 n.mi. offshore (25 n. mi. @ 6 kts)	4.5	50%	3500	2616	n/a	346	44	16	13	136.1	18721.4	18.0	2.28	0.82	0.69	0.708	973.511
	1 tug transit back to port from release of Carrier 3 n. mi. offshore (25 n.mi. @ 10 kts)	2.5	80%	5600	4186	n/a	307	39	14	12	90	16641.2	16	2	1	1	0.470	865
	Subtotal	**17.6**					**2436.9**	**309.2**	**111.6**	**93.3**	**876.0**	**131964.8**	**126.7**	**16.1**	**5.8**	**4.9**	**4.6**	**6862.2**
	Tug boat pushing empty barge to dock (10 n. mi. @ 5 kts.)	2.0	90%	6300	4709	n/a	277	35	13	11	81	14977	14.4	1.8	0.7	0.6	0.4	779
Barge Loading	Tug boat maneuvering barge to dock	1.0	90%	6300	4709	n/a	138	18	6	5	41	7489	7.2	0.9	0.3	0.3	0.2	389
One Tug Boat	Tug boat standby while barge loaded	2.0	10%	700	523	n/a	31	4	1	1	9	1664	1.6	0.2	0.1	0.1	0.0	87
	Tug boat maneuvering barge away from dock	1.0	90%	6300	4709	n/a	138	18	6	5	41	7489	7.2	0.9	0.3	0.3	0.2	389
	Tug boat pushing barge to destination (10 n. mi. @ 5 kts.)	2.0	90%	6300	4709	n/a	277	35	13	11	81	14977	14.4	1.8	0.7	0.6	0.4	779
	Subtotal						**860**	**109**	**39**	**33**	**253**	**46595**	**45**	**6**	**2**	**2**	**1**	**2423**
TOTAL							**3783**	**749**	**282**	**143**	**1263**	**289334**	**196.7**	**38.9**	**14.7**	**7.5**	**12.8**	**15045**

Notes: 1 tug meets carrier 3 n. mi. offshore

2 addnl tugs meet carrier 3.5 miles (3.01 n. mi.) from Magnolia

This page left blank intentionally.

Appendix 9.C.3

Modeling Protocol - Ozone Impact Analysis of the Proposed Magnolia LNG Project

This page left blank intentionally.

Magnolia LNG LLC
1001 McKinney St. Suite 400
Houston, TX 77002
713-815-6900
www.magnolialng.com

March 25, 2014

Via Email and UPS

Tegan Treadaway
Louisiana Department of Environmental Quality
Air Quality Supervisor
P.O. Box 4313
Baton Rouge, LA 70821-4313

Re: Magnolia LNG Ozone Study Protocol and Request for Time Extension for the Magnolia LNG Dispersion Modeling Protocol Approved on January 22, 2014

Dear Tegan,

Magnolia LNG LLC, (Magnolia) is pleased to submit the enclosed protocol "Ozone Impact Analysis of the Proposed Magnolia LNG Project" for LDEQ's review. Magnolia is utilizing the services of Alpine Geophysics, LLC (Alpine) for the study.

Although a detailed photochemical modeling analysis for ozone is not required by regulation, Magnolia understands LDEQ's interest in evaluating facility ozone impacts on a case-by-case basis to allow decision makers to understand the potential ozone impacts of the proposed Project. The protocol describes the study approach, model to be used, and method for evaluating results. Ozone impact assessment modeling will utilize the Comprehensive Air Quality Model with Extensions (CAMx) in conjunction with the 17 August through 31 October 2010 ozone episode.

Magnolia also requests an approval time extension for the Magnolia LNG Dispersion Modeling Protocol approved by LDEQ on January 22, 2014. Magnolia is continuing work on the dispersion modeling study and refining emission source input data.

We appreciate LDEQ's review of the ozone modeling study protocol, and consideration of the approval extension request for the Dispersion Modeling Study protocol. Please indicate if LDEQ will forward the Ozone Study protocol to USEPA Region 6 for their review as well. Should you have any questions or require any additional information, please do not hesitate to contact myself at 713-815-6930 or khassan@magnolialng.com; Bruce Wattle at 716-684-8060 ext. 2572 or bwattle@ene.com; or Bill Daughdrill at 850-435-8925 ext. 4303 or wdaughdrill@ene.com.

Thank you,

Komi O. Hassan

Enclosure:

cc: Bryan Johnston, Yvette Olmos

This page left blank intentionally.

MAGNOLIA LNG PROJECT

Modeling Protocol

Ozone Impact Analysis of the Proposed Magnolia LNG Project

25 March 2014

Submitted to:

Louisiana Department of Environmental Quality

Submitted by:

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ALPINE GEOPHYSICS
Atmospheric & Hydrologic Sciences

ecology and environment, inc.
Global Environmental Specialists

This page left blank intentionally.

Final Modeling Protocol

Ozone Impact Analysis of the Proposed Magnolia LNG Project

Prepared for:

Ecology and Environment, Inc.
368 Pleasant View Dr.
Lancaster, NY 14086

And

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

Dennis McNally
Cyndi Loomis
Alpine Geophysics, LLC
7341 Poppy Way
Arvada, Colorado 80007

25 March 2014

This page left blank intentionally.

Table of Contents

Section No. Page No.

1 INTRODUCTION 1-1

1.1 OVERVIEW 1-1
1.2 STUDY APPROACH 1-3

2 TECHNICAL APPROACH 2-1

2.1 PROJECT EMISSIONS AND STACK PARAMETERS 2-1
2.2 17 AUG – 31 OCTOBER 2010 CAMX MODELING DATA BASES 2-1
2.3 APPLICATION OF EPA GUIDANCE FOR OZONE MODELING OF THE NAAQS 2-1
2.4 APPLICATION OF 8-HR OZONE IMPACT METRICS 2-2

APPENDIX A: ROUGH PROTOCOL OUTLINE PREPARED BY USEPA REGION VI. 1

List of Figures

Figure No. **Page No.**

Figure 1-1: General Location Map of the Magnolia LNG Project 1-4
Figure 2-1. 36/12/4 km LDEQ 2010 CAMx Domain. 2-4
Figure 2-2. Proposed Magnolia LNG Facility Location Within the 4km CAMx Grid. 2-5

List of Acronyms

BPA	Beaumont/Port Arthur
BRMSA	Baton Rouge Metropolitan Statistical Area
BRNAA	Baton Rouge Non-attainment Area
BSCF	Billion Standard Cubic Feet
CAIR	Clean Air Interstate Rule
CAMx	Comprehensive Air Quality Model with Extensions
CHP	Combined Heat and Power
DVc	Current Year Design Value
DVf	Future Year Design Value
EPA	United States Environmental Protection Agency
HGB	Houston/Galveston/Brazoria
LDEQ	Louisiana Department of Environmental Quality
LLC	Limited Liability Corporation
LNG	Liquefied Natural Gas
MATS	Modeled Attainment Test Software
MTPA	Million (metric) Tonnes Per Anum
NAAQS	National Ambient Air Quality Standard
NOx	Oxides of Nitrogen
OSMR®	Optimized Single Mixed Refrigerant
PPB	Parts per Billion
RRF	Relative Response Factor
SMOKE	Sparse Matrix Operator Emissions
SMR	Single Mixed Refrigerant
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
WRF	Weather/Research/Forecast Meteorological Model

1 INTRODUCTION

1.1 Overview

Magnolia LNG, LLC (Magnolia) is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The Project would receive natural gas via a tie-in to an existing interstate pipeline that traverses the proposed Project site.

The natural gas would be treated, liquefied, and stored on-site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states. The Project site is well-positioned to provide access for loading of LNG carriers and also for potential LNG barges and LNG trucks.

Approximately 1.4 billion standard cubic feet per day (Bscf/d) of natural gas would be contracted for transportation to the Project site via the interstate pipeline to support Project operations. The core of each LNG train would be a single mixed refrigerant (SMR) process. This simple SMR process is then optimized by the use of three proven technologies: aero-derivative gas turbines, combined heat and power (CHP) technology, and ammonia auxiliary refrigeration. The integration of these proven technologies to enhance the SMR process resulted in the patented OSMR® process technology.

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1-1 is a general location map of the Project.

This report summarizes the photochemical grid modeling to be performed for determining 8-hour ozone impacts from emissions from the proposed project. The proposed site for the Project is located in Calcasieu Parish which is currently designated as attainment for 8-hour ozone. However, it is nearby to parishes in the Baton Rouge Metropolitan Statistical Area (BRMSA) that are designated as nonattainment for 8-hour ozone, the Houston/Galveston/Brazoria ozone non-attainment area and the Beaumont/Port Arthur area. Due to the quantity of ozone precursor

emissions and its proximity to these areas, a modeling analysis is proposed to quantify its potential impact on ozone concentrations in the surrounding area.

A detailed photochemical modeling analysis for ozone is not required by regulation. Facility ozone impacts are handled on a case-by-case basis. This modeling is to be performed external to the statutory permit process in order to allow decision makers to better understand the potential ozone impacts of the proposed project. Furthermore, guidance does not exist on application, analysis or interpretation of single source ozone impact analyses. Thus, the analysis and interpretation of the results is handled in an ad-hoc, case by case basis. In the absence of specific guidance, the modeling will be conducted using both the suggestions by EPA Region 6, and the only guidance available, namely the application of photochemical models for attainment of the ozone National Ambient Air Quality Standard (NAAQS).

1.2 Study Approach

The potential 8-hr ozone impact of the proposed project emissions will be quantified using the state-of-science regional photochemical model, the Comprehensive Air Quality Model with Extensions (CAMx) in conjunction with the 17 August through 31 October 2010 ozone episode prepared for the Louisiana Department of Environmental Quality (LDEQ). The general methodology of using the CAMx model and the LDEQ CAMx modeling platform was recommended by U.S. EPA, Region 6 and has been used for the Nucor Steel pig iron plant in Baton Rouge, the Cheniere Sabine Pass Liquefaction, and Cameron LNG facilities in Cameron Parish, Louisiana, and the Sasol North America Lake Charles Cracker Complex and Gas-to-Liquids projects in Calcasieu Parish.

The LDEQ CAMx model was prepared for the 2008 8-Hour Ozone NAAQS Modeling Project[1] and fully described in the August 2013 Technical Support Document[2].

This analysis will consist of running the CAMx photochemical model three times. Two simulations (base.run17typ – 2010 typical base case and fy2017.run17 – 2017 future case) have already been performed to confirm proper operation of the modeling system on the Alpine Geophysics, LLC computer system. In comparison with the simulation provided by LDEQ, the Alpine simulation agreed to within $1x10^{-6}$ ppb for ozone. This level of agreement was expected because the modeling was conducted with the same model executable, input files, and computer platform as the simulation conducted by the LDEQ contractor. However, this initial assessment was necessary to confirm that the modeling platform transfer did not impact the modeling results.

The third and final simulation will be identical to the base case except that the estimated projected maximum allowable emissions from Magnolia LNG project will be added to the future year elevated point source emissions files to quantify the impact.

The CAMx modeling results will be analyzed in a manner consistent with EPA guidance on application of photochemical models for attainment of the ozone NAAQS[3] , namely the Relative Response Factor (RRF) approach, and using an absolute impact approach. The RRF approach, as well as other details of the analyses, are described more fully in Section 2.

1http://www.deq.louisiana.gov/portal/DIVISIONS/AirPermitsEngineeringandPlanning/NationalAmbientAirQualityStandards/Ozone/20088HourOzoneNAAQSModelingProject.aspx

2http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/Engineering/Ozone/LDEQ_TSD_4Oct13.pdf

3 EPA, 2007. ”Guidance on The Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze”, EPA-454/B-07-002. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC. April. (262 pgs.)

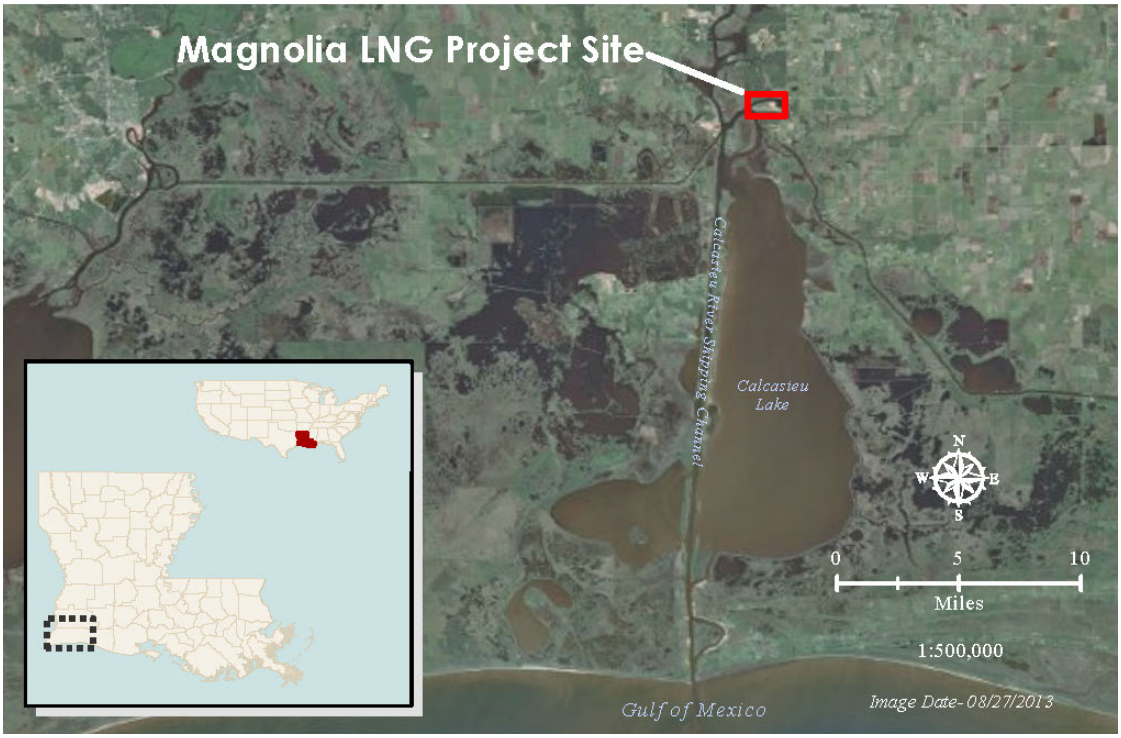


Figure 1-1: General Location Map of the Magnolia LNG Project

2 Technical Approach

The incremental 8-hr ozone impacts due to emissions from the proposed facility will be quantified within the Baton Rouge, Lake Charles, Beaumont/Port Arthur and Houston areas. This section expands on the CAMx modeling methodology, emissions input assumptions, and analysis procedures presented in Section 1.1.

2.1 Project Emissions and Stack Parameters

The emissions for the proposed facilities will be processed using the Sparse Matrix Operator Emissions (SMOKE) emissions model to prepare the hourly, speciated elevated point source format required by CAMx. The photochemical modeling will use the same stack parameters used in the AERMOD modeling. Since the LDEQ 2010 CAMx modeling did not include a Plume-in-Grid treatment for any sources, the project sources will not be treated as Plume-in-Grid sources.

2.2 17 Aug – 31 October 2010 CAMx Modeling Data Bases

The final (Run 15) CAMx modeling files for the 17 Aug – 31 October 2010 modeling episode have been obtained on external hard drive from the LDEQ. This modeling was conducted on a 36/12/4 kilometer (km) nested grid configuration shown in Figure 2-1. (LDEQ, 2007; LDEQ, 2008; LDEQ, 2009). Consistent with the analysis by LDEQ, the analysis will be restricted to the 4km domain shown in Figure 2-2.

2.3 Application of EPA Guidance for Ozone Modeling of the NAAQS

The CAMx modeling results will be analyzed in a manner consistent with EPA guidance on application of photochemical models for attainment of the ozone NAAQS (USEPA, 2007). USEPA guidance for projecting future 8-hour ozone concentrations recommends using the photochemical grid model in a relative sense to scale current observed 8-hour design values. A design value is defined as a 3-year average of the fourth highest daily maximum 8-hour ozone concentrations at a monitor. Model scaling factors, referred to as relative response factors (RRFs), are used to scale the observed design values in order to predict future year design values. RRFs are the ratio of the future year (or a project impact case) to the current-year modeled 8-hour ozone concentrations near a monitor site. USEPA has defined “near the monitor” to be approximately 15 km from the monitor location. The future-year design value (DVf) is obtained from the current-year design value (DVc) using the relation:

$$DVf = DVc \ x \ RRF$$

The RRFs are calculated for all days in which the current-year modeled 8-hour ozone value is above a threshold. This is done so that the model response to future changes in emissions is

considered only on high ozone days of comparable conditions to the days used to produce the DVc. USEPA recommends a threshold between 70 and 85 ppb.

To perform the 8-hour projections, USEPA has developed the Modeled Attainment Test Software (MATS) tool that uses modeling results, 8-hour ozone design values and follows USEPA guidance (USEPA 2007) to project 8-hour ozone concentrations that reflect the change in emissions from the base case to an alternative emissions scenario.

EPA recommends using a DVc based on an average of three year 8-hour ozone Design Values that span 5 consecutive years centered on the modeling year (i.e., a weighted average of 5 years of fourth highest daily maximum 8-hour ozone concentrations). For example, for the 2010 baseline modeling year used in this analysis, this would mean the DVc at a given monitor would be the weighted average of the fourth highest 8-hour daily maximum ozone at that monitor from the years 2008, 2009, 2010, 2011 and 2012 using weights of 1, 2, 3, 2 and 1, respectively. To develop RRFs, EPA guidance recommends using current and future modeling results for all days in which the current year daily maximum 8-hour ozone concentration near the monitor exceeds an ozone threshold value. For a 4-km grid, as in the Baton Rouge Redesignation modeling, the maximum modeled daily maximum 8-hour ozone concentration in a 7 x 7 array of grid cells centered on the monitor is used. EPA recommends using an 8-hour ozone threshold concentration of 85 ppb and also recommends that RRFs be based on a minimum of 5 days, although a total of 10 days or more is preferred. EPA allows a reduction of the threshold value to 70 ppb to meet the minimum 5-10 days requirement.

The 8-hour ozone projections will be performed twice. The first projection will be performed using the 2010 typical simulation (base.run17typ) and the Future Year Base Case (fy2017.run17). Projections will then be run comparing the project emissions case to the 2010 typical simulation (base.run17typ). The project impacts are the differences in the future design values between the project emissions simulations and the Future Year Base case simulation.

2.4 Application of 8-hr Ozone Impact Metrics

EPA has not determined a significance threshold for ozone impacts, nor has it developed a strict guidance for metrics to use for assessing single source ozone impacts. Rather, the determination of metrics, and the interpretation of these metrics, is handled on a case-by-case basis.

In addition to the previously described application of the ozone modeling for the NAAQS, a variety of graphical displays and metrics will be used to assess and quantify the ozone air quality impacts associated with the proposed facility. These metrics were selected by USEPA Region 6 in assessing the Nucor Steel facility near Baton Rouge, LA (McNally, 2008). The modeling protocol prepared by USEPA Region 6 is presented in Appendix A. Since the time this protocol was prepared, U.S. EPA Region 6 has suggested lowering the thresholds from 80 parts per billion (ppb) to 75 ppb to better reflect the updated ozone National Ambient Air Quality Standard (NAAQS), and lowering the impact threshold from 0.3 to 0.2 ppb.

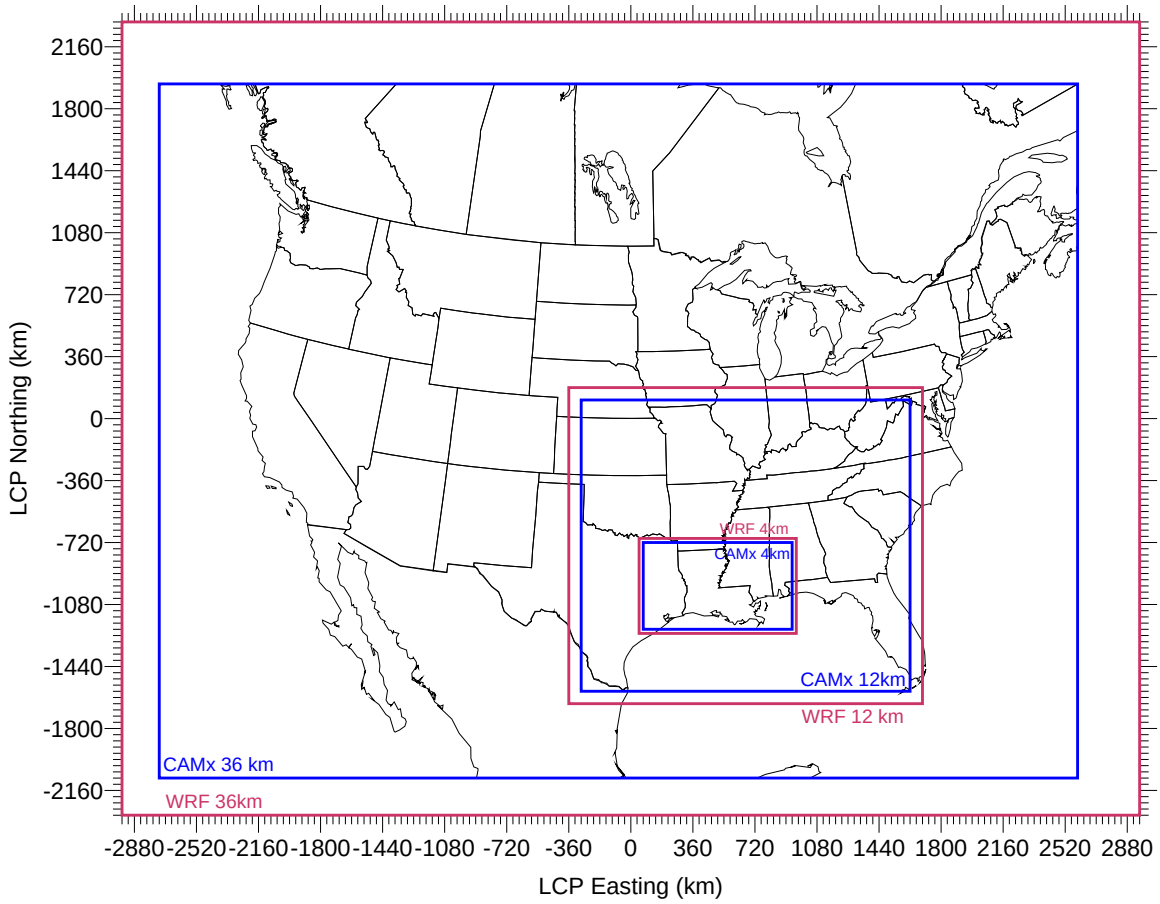
Graphical displays will include daily maximum 8-hour difference plots between the simulations with and without the proposed facility emissions.

Tabular metrics will include:

- Number of grid cell days with increases in maximum simulated 8-hr ozone > 0.2 ppb
- Number of grid cell days with increases in maximum simulated 8-hr ozone > 1.0 ppb
- Number of grid cells with simulated 8-hour ozone concentrations ≥ 75 ppb
- Number of grid cell-hrs with simulated 8-hour ozone concentrations ≥ 75 ppb
- Amount of ozone ≥ 75 ppb summed over all hours and grid cells
- Amount of ozone ≥ 75 ppb squared summed over all hours and grid cells

For the monitor areas; two additional metrics will be used. These include:

- Simulated maximum 8-hour ozone in the vicinity of each monitor for each day
- Simulated average 8-hour ozone in the vicinity of each monitor for each day for the time period that the maximum value occurred.



Louisiana WRF/CAMx Modeling Domains

CAMx
36 km: 148 x 112 (-2736, -2088) to (2592, 1944)
12 km: 159 x 141 (-288, -1584) to (1620, 108)
4 km: 216 x 126 (72, -1224) to (936, -720)

WRF:
36 km: 165 x 129 dot points (-2952, -2304) to (2952, 2304)
12 km: 172 x 154 dot points (-360, -1656) to (1692, 180)
04 km: 229 x 139 dot points (48, -1248) to (960, -696)

Figure 2-1. 36/12/4 km LDEQ 2010 CAMx Domain.

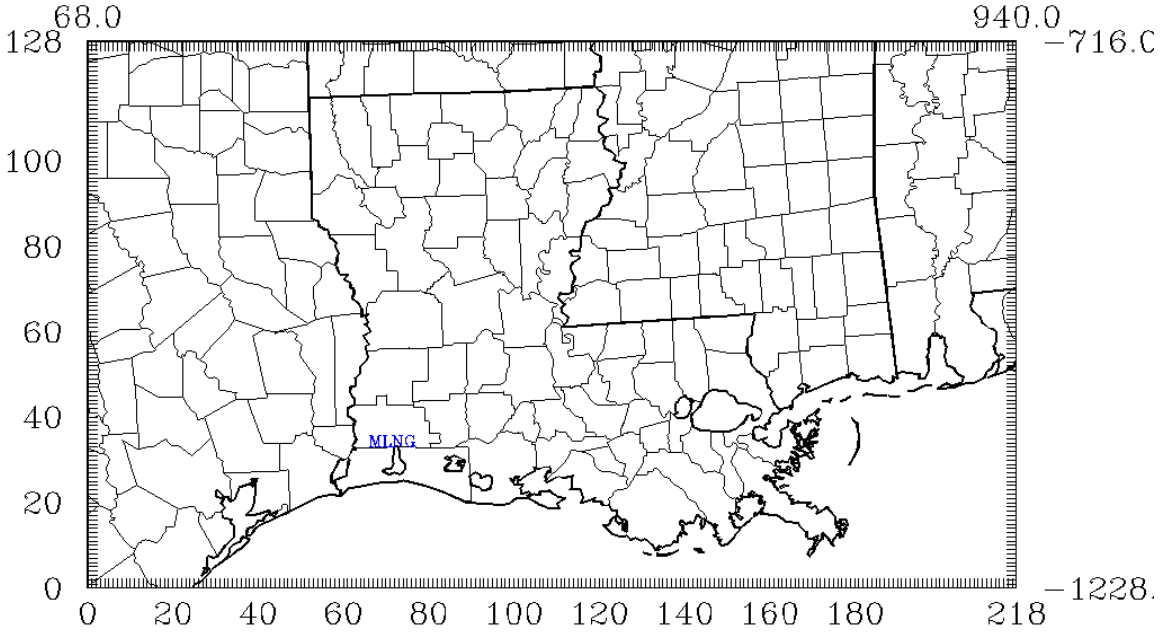


Figure 2-2. Proposed Magnolia LNG Facility Location Within the 4km CAMx Grid.

This page left blank intentionally.

Appendix A: Rough Protocol Outline Prepared by USEPA Region 6.

Nucor Ozone Impact Modeling Analysis

An ozone impact analysis can be done using the current CAMx basecase modeling for Baton Rouge (June 2006 episode). Further improvements in the basecase modeling are expected to occur, but the current basecase Run 4 is considered to be performing satisfactorily enough to use for evaluation of potential ozone impacts of the new Nucor facility.

This analysis will be conducted using the June 2006 episode basecase Run 4 modeling outputs and another basecase Run 4 with the proposed additional Nucor emissions (Run 4-N). After the completion of Run 4-N, post-processing of the outputs will be conducted.

Overview of Metrics Used for Impact Assessment

A variety of graphical displays and metrics will be used to assess and quantify the ozone air quality impacts associated with the Nucor related emissions changes. Of primary importance is the impact on modeled values for 8-hour ozone that are near or above the standard. Since the basecase has a slight under-prediction bias and will continue to be improved, we will be slightly conservative and use a 80 ppb threshold instead of 85 ppb. Evaluations will be done for three areas: around existing monitors (Mon), all grid cells in the Baton Rouge NAA (BRNAA), and all grid cells within the greater Baton Rouge MSA (BRMSA). We will also use additional analyses to establish the spatial and temporal distribution and significance of any impacts.

Several metrics will be used to characterize impacts on the three areas (Mon, BRNAA, BRMSA) ozone levels using the 80 ppb threshold. These metrics should be calculated for both the Run 4 and Run 4-N and also the delta between these two runs where appropriate. These include[1]:

- Daily Maximum 8-hour ozone concentration (including daily delta plots-could be included in plots for next metric)
- Number of grid cells with increases in maximum simulated 8-hour ozone > 0.3 ppb and >1 ppb (including daily delta plots for the two cut points)
- 8-hour ozone exceedance exposure metric of ppb*hr, ppb*hr^2 (using decimals)
- Number of grid cells with simulated 8-hour ozone concentrations ≥ 80 ppb
- Number of grid cell-hours with simulated 1-hour ozone concentrations ≥ 80 ppb
- Amount of ozone ≥ 80 ppb summed over all hours and grid cells.

For the Mon area, two additional metrics will be used to characterize impacts in the vicinity of each site. These include:

- Simulated maximum 8-hour ozone in the vicinity[2] of each monitor for each day
- Simulated average 8-hour ozone in the vicinity[2] of each monitor for each day for the same period that the maximum value occurred.

[1] The 0.3 ppb and 1 ppb cut points are not official EPA guidance, but are being used for evaluation purposes. For CAIR and NOx SIP call, EPA used 2 ppb thresholds for entire state impacts.

[2] Defined by the 7 by 7 array of grid cells surrounding each monitoring site, or an approximate 15-km radius of influence.

This page left blank intentionally.

Appendix 9.D
Noise Study

This page left blank intentionally.

MAGNOLIA LNG PROJECT
Lake Charles, Louisiana

BASELINE NOISE STUDY REPORT

November 2013

Prepared for:

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

©2013 Ecology and Environment, Inc.

This page left blank intentionally.

TABLE OF CONTENTS

Section Page

1.0 INTRODUCTION.....1

2.0 SOUND FUNDAMENTALS.....1

3.0 EXISTING AMBIENT NOISE 4

4.0 METHODOLOGY 4

5.0 RESULTS 9

6.0 REFERENCES.....9

LIST OF TABLES

Page

Table 1 Decibel Level of Some Common Sounds 3
Figure 1 Ambient Noise Measurement Locations 5
Table 2 Existing Noise Level Summary for the Project Area 9

LIST OF FIGURES

Page

Figure 2 Hourly LAeq Noise Level (dBA) – Receptor 1 10
Figure 3 Hourly LAeq Noise Level (dBA) – Receptor 2 11
Figure 4 Hourly LAeq Noise Level (dBA) – Receptor 3 12

LIST OF PHOTOGRAPHS

Page

Photograph 1 West end of Private Drive off Big Lake Road, north of Airhart Road 7
Photograph 2 East end of Private Drive off Big Lake Road, north of Airhart Road 7
Photograph 3 8366 Joe Ledoux Road 8

1.0 INTRODUCTION

Magnolia LNG, LLC (Magnolia) is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million metric tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The proposed project is referred to herein as the Magnolia LNG Project, or the Project. The Project would receive natural gas via an existing pipeline that traverses the proposed Project site. The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; onto LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and onto LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

The Project would be located on Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, Louisiana, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline.

This report summarizes the locations, methodology, and noise measurements results for the noise survey conducted by Ecology and Environment, Inc. from September 23 through September 25, 2013. The purpose of the study was to characterize the existing noise environment at the nearest noise sensitive areas (NSAs).

2.0 SOUND FUNDAMENTALS

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities. The unit of noise measurement is a decibel (dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as A-weighted decibels (dBA). ("A" indicates that the sound has been filtered to reduce the strength of very low and very high frequency sounds, much as the human ear does.) The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans do not perceive the 10-dBA increase as 10 times louder, but as only twice as loud.

The following is typical of human responses to changes in noise level:

- A 3-dBA change is the threshold of change detectable by the human ear.
- A 5-dBA change is readily noticeable.
- A 10-dBA change is perceived as a doubling (or halving) of noise level.

Table 2-1 lists typical sources and levels of noise and corresponding human responses to the noise.

Noise sources that affect the environment can be mobile sources such as automobiles, buses, trucks, aircraft, and trains, or stationary sources such as machinery or mechanical equipment associated with industrial and manufacturing operations or building heating, ventilating, and air-conditioning systems. Sources of construction noise are both mobile sources (e.g., trucks, bulldozers, etc.) and stationary sources (e.g., compressors, pile drivers, power tools, etc.).

The sound pressure level (SPL) that humans experience typically varies from moment to moment. Therefore, various descriptors are used to evaluate sound levels over time. Some typical descriptors are defined below.

- L_{eq} is the continuous equivalent sound level. The sound energy from the fluctuating SPLs is averaged over time to create a single number to describe the mean energy, or intensity, level. The duration of the measurement would be shown as $L_{eq}(n)$. A 24-hour measurement would be shown as $L_{eq}(24)$. The L_{eq} has an advantage over other descriptors because L_{eq} values from various sound sources can be combined to determine cumulative sound levels.
- LA_{eq} is the A-weighted L_{eq} value.
- L_n is the SPL exceeded for n percent of the time. In other words, for n percent of the time, the fluctuating SPLs are higher than the L_n level. L_n can be obtained by analyzing a given noise by statistical means. L_{50} is the level exceeded for 50 percent of the time.
- L_{dn} is equivalent to a 24-hour L_{eq}, but with a 10-dBA penalty added to nighttime noise levels (10:00 p.m. to 7:00 a.m.) to reflect the greater intrusiveness of noise experienced during this time.

Table 1 Decibel Level of Some Common Sounds

Sound Source	dB(A)	Perception/Response
	150	
Carrier Deck Jet Operation	140	
	130	Painfully Loud Limit
Jet Takeoff (200 feet) Discotheque	120	
Auto Horn (3 feet) Riveting Machine	110	
Jet Takeoff (2,000 feet) shout (0.5 feet)	100	
N.Y. Subway Station Heavy Truck (50 feet)	90	Very Annoying Hearing Damage (8 hours, continuous exposure)
Pneumatic Drill (50 feet)	80	Annoying
Freight Train (50 feet) Freeway Traffic (50 feet)	70	Telephone Use Difficult Intrusive
Air Conditioning Unit (20 feet)	60	
Light Auto Traffic (50 feet)	50	Quiet
Living Room Bedroom	40	
Library Soft Whisper (15 feet)	30	Very Quiet
Broadcasting Studio	20	
	10	Just Audible
	0	Threshold of Hearing

Source: New York State Department of Environmental Conservation 2001

3.0 EXISTING AMBIENT NOISE

Ambient baseline, or background, sound levels are a function of such things as local traffic, farm machinery, barking dogs, birds, insects, lawnmowers, children playing, and the interaction of the wind with ground cover, buildings, trees, shrubs, power lines, etc. The sound levels vary with time of day, wind speed and direction, and the level of human activity.

4.0 METHODOLOGY

Continuous long-term sound levels were measured statistically in consecutive 1-hour intervals at three noise sensitive property locations in the area. Three Rion NL series ANSI Type I integrating sound level meters were used to carry out the survey. Each of these instruments is intended for use as a long-term environmental sound level data logging instrument measuring the A-weighted sound level. All of the meters were set to continuously record a number of statistical parameters in consecutive 1-hour intervals, including the average $LA_{eq,}$ L_{10}, and L_{50} sound levels. The survey period began on September 23, 2013, and continued over three days, until September 25, 2013.

The microphones used in the survey were protected from rain and self-induced wind noise by high-density foam windscreens designed for long-term outdoor service. In order to further minimize self-induced wind noise, all microphones were located at approximately 1 meter above local grade. Wind speed is a function of elevation and rapidly diminishes near the ground.

The Project site is located in a mixed industrial and rural area with no residents within 0.5 mile of the site and approximately 30 residences within a 1-mile radius of the site. The noise sources in the area include wind, birds, insects, distant industrial facilities, boat traffic, and vehicular traffic on local roads. The nearest NSA (NSA #1) is a residence located about 3,820 feet south of the center of the proposed LNG liquefaction trains.

Sound level measurements were collected at the nearest NSAs to the Project site identified as follows:

- NSA #1 West end of Private Drive off Big Lake Road, north of Airhart Road;
- NSA #2 East end of Private Drive off Big Lake Road, north of Airhart Road; and
- NSA #3 8366 Joe Ledoux Road.

The locations of the noise measurement stations can be seen on Figure 1 and in Photographs 1, 2, and 3.

Weather Conditions

Meteorological conditions during the measurements included clear to partly cloudy skies, northwest winds of 3 to 7 miles per hour and temperatures from 66 to 93 degrees Fahrenheit.

Document Path: C:\VPN_WORK\active_projects\Magnolia_LNG\maps\mxds\mxd_noise_study\Nearest NSA Locations.mxd

Figure 1
Ambient Noise Measurement Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary

Ambient Noise Measurement Locations

N W E S

MAGNOLIA LNG

0 1,000 2,000 Feet

1:12,000

Source- ESRI 2011-2012

Date: 11/20/2013

This page left blank intentionally.

Photograph 1 - West end of Private Drive off Big Lake Road, north of Airhart Road

Photograph 2 - East end of Private Drive off Big Lake Road, north of Airhart Road

Photograph 3 - 8366 Joe Ledoux Road

5.0 RESULTS

Figures 2 through 4 show the hourly average LA_{eq} sound level measured at NSAs #1, #2, and #3, respectively, over the three-day period.

The Ldn for each NSA was calculated using the measured LA_{eq}s in the following formula:

$$Ldn = 10\log10 \quad 1/24\ [15 \times 10^{(\text{Average Leq Day}/10)} + 9 \times 10^{(\text{Average Leq Night}+10)/10}]$$

A summary of the existing noise levels is provided in Table 2.

Table 2 Existing Noise Level Summary for the Project Area

NSA	Distance from NSA (feet)	Direction from NSA	Average Daytime L_{eq} (dBA)	Average Nighttime L_{eq}(dBA)	Calculated L_{dn} (dBA)
#1	3,820	North	46.9	43.8	50.8
#2	4,485	Northwest	48.7	44.8	52.0
#3	7,075	Northwest	43.6	40.2	47.3

6.0 REFERENCES

New York State Department of Environmental Conservation. June 3, 2001 (rev.). Program Policy DEP-00-1, *Assessing and Mitigating Noise Impacts.*

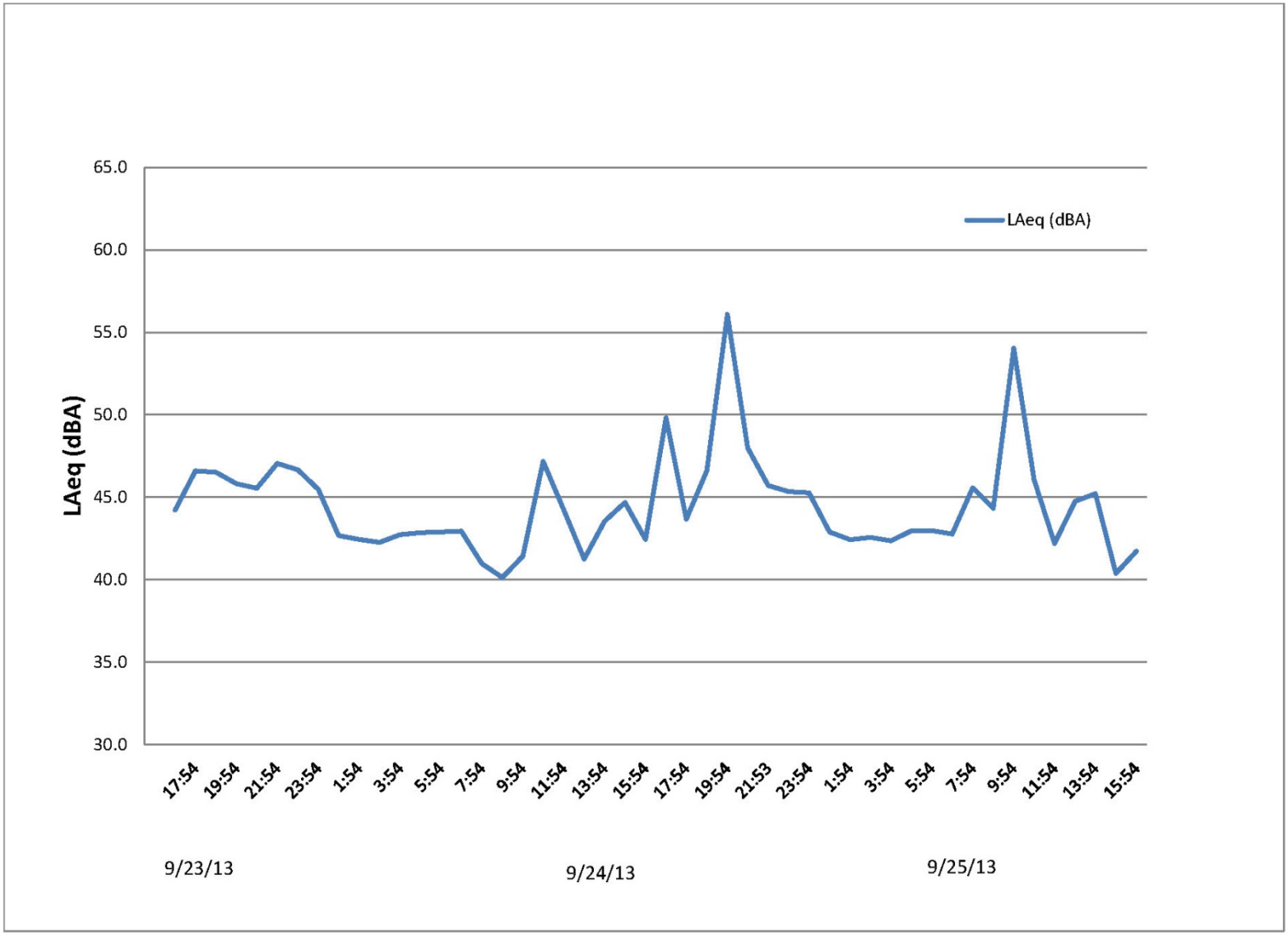


Figure 2 Hourly LAeq Noise Level (dBA) – Receptor 1

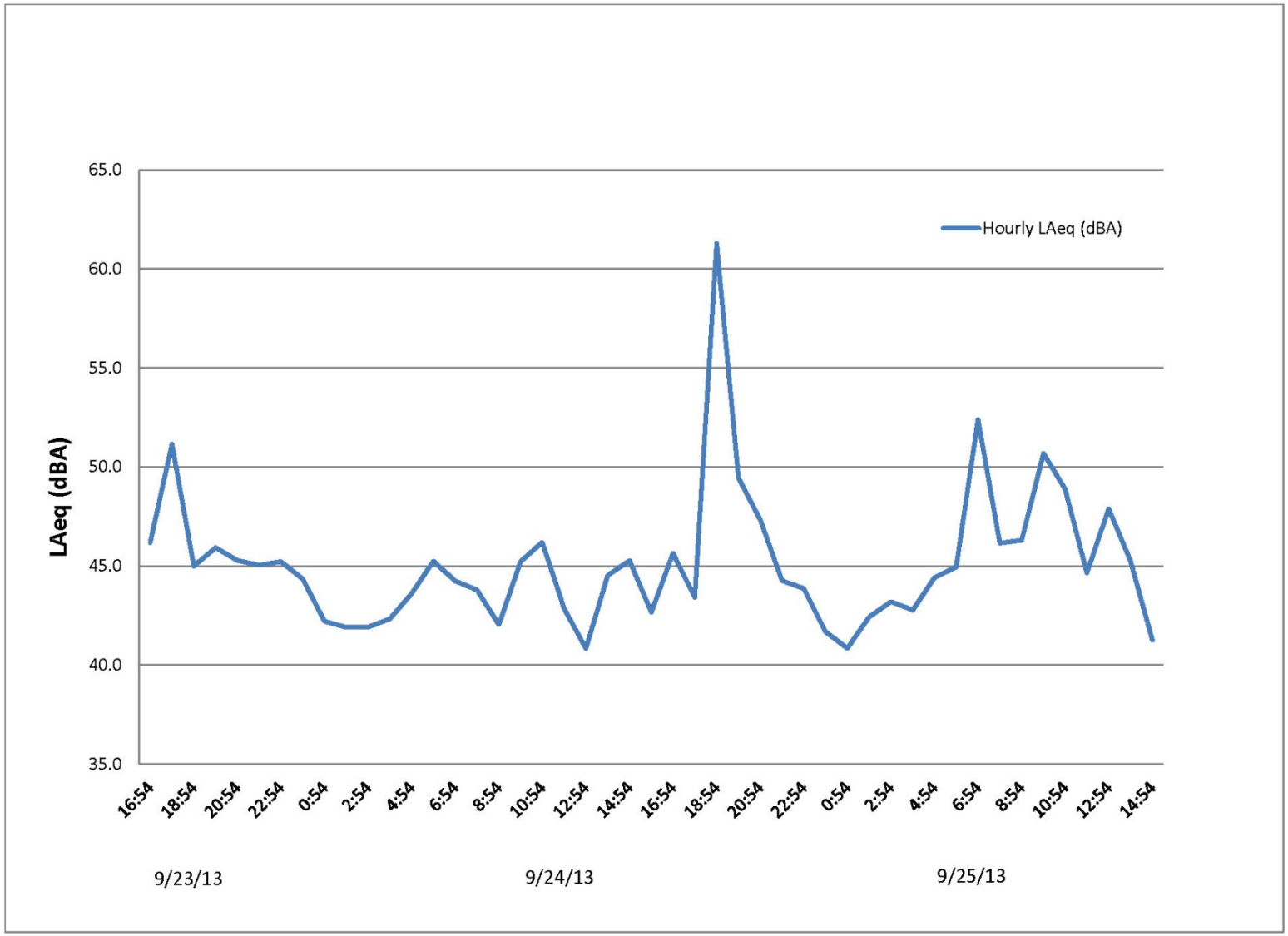


Figure 3 Hourly LAeq Noise Level (dBA) – Receptor 2

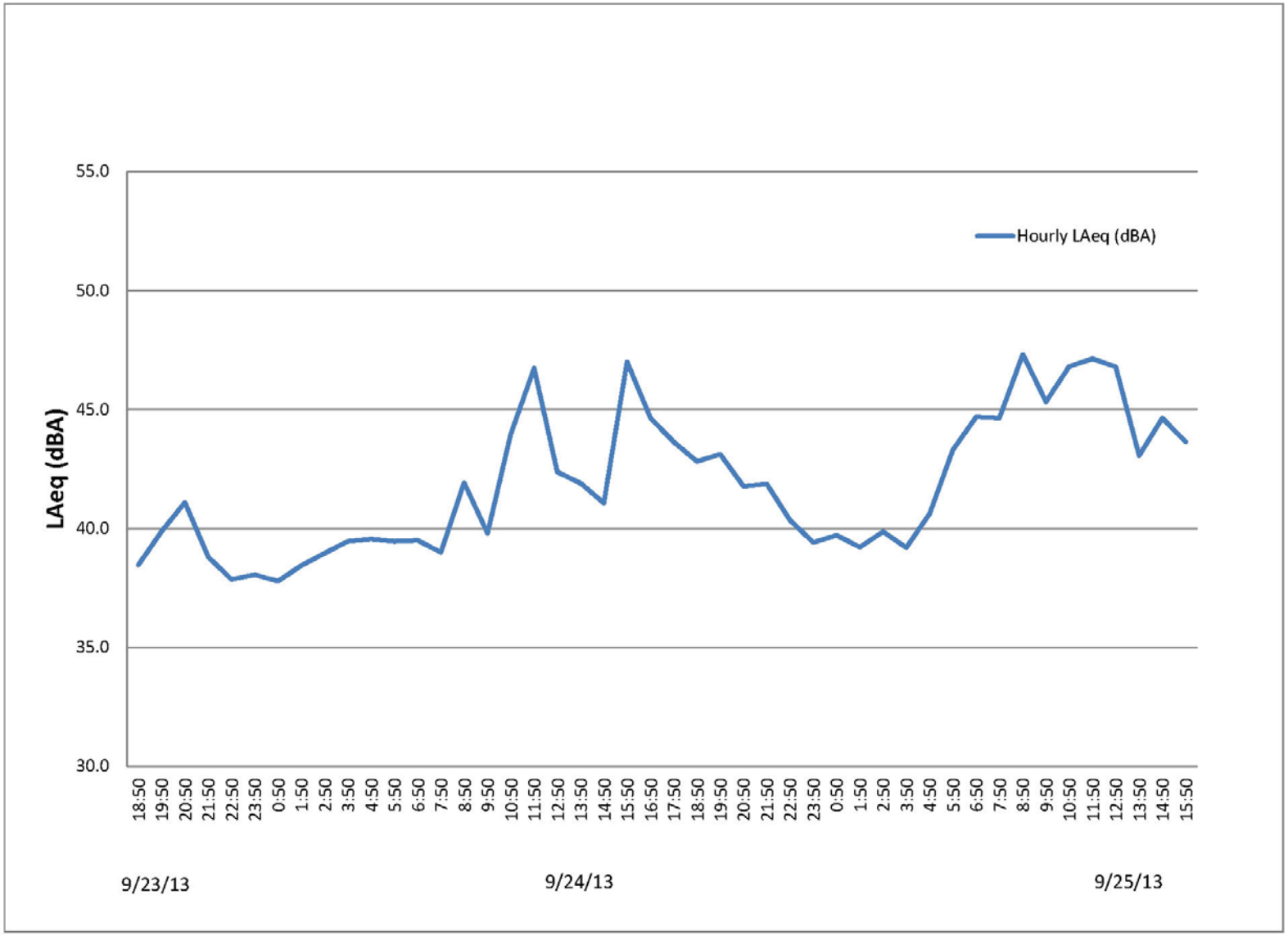


Figure 4 Hourly LAeq Noise Level (dBA) – Receptor 3

Appendix 9.E
Air Permit Application

[Pending LDEQ Review]

This page left blank intentionally.

Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

July 2011

CONTACT INFORMATION

This document has been prepared by staff from the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Questions related to this document should be addressed to Alexander Macpherson, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, C445-B, Research Triangle Park, North Carolina 27711 (email: macpherson.alex@epa.gov).

ACKNOWLEDGEMENTS

In addition to EPA staff from the Office of Air Quality Planning and Standards, personnel from the U.S. EPA Office of Atmospheric Programs, EC/R Incorporated, and ICF International contributed data and analysis to this document. Specific sections where EC/R Incorporated made contributions include the sections describing emissions options, pollution control options, secondary impacts analysis, engineering cost analysis, and employment impacts. Specific sections where ICF International made contributions also include the sections describing emissions options, pollution control options, engineering cost analysis, employment impacts, and small business impacts.

TABLE OF CONTENTS

TABLE OF CONTENTS III

LIST OF TABLES VI

LIST OF FIGURES VIII

1 EXECUTIVE SUMMARY 1-1

1.1 BACKGROUND 1-1
1.2 NSPS RESULTS 1-2
1.3 NESHAP AMENDMENTS RESULTS 1-5
1.4 ORGANIZATION OF THIS REPORT 1-7

2 INDUSTRY PROFILE 2-1

2.1 INTRODUCTION 2-1
2.2 PRODUCTS OF THE CRUDE OIL AND NATURAL GAS INDUSTRY 2-2
2.2.1 Crude Oil 2-2
2.2.2 Natural Gas 2-2
2.2.3 Condensates 2-3
2.2.4 Other Recovered Hydrocarbons 2-3
2.2.5 Produced Water 2-4
2.3 OIL AND NATURAL GAS PRODUCTION PROCESSES 2-4
2.3.1 Exploration and Drilling 2-4
2.3.2 Production 2-5
2.3.3 Natural Gas Processing 2-7
2.3.4 Natural Gas Transmission and Distribution 2-8
2.4 RESERVES AND MARKETS 2-8
2.4.1 Domestic Proved Reserves 2-9
2.4.2 Domestic Production 2-13
2.4.3 Domestic Consumption 2-21
2.4.4 International Trade 2-24
2.4.5 Forecasts 2-26
2.5 INDUSTRY COSTS 2-31
2.5.1 Finding Costs 2-31
2.5.2 Lifting Costs 2-33
2.5.3 Operating and Equipment Costs 2-34
2.6 FIRM CHARACTERISTICS 2-36
2.6.1 Ownership 2-36
2.6.2 Size Distribution of Firms in Affected 2-37
2.6.3 Trends in National Employment and Wages 2-39
2.6.4 Horizontal and Vertical Integration 2-44
2.6.5 Firm-level Information 2-45
2.6.6 Financial Performance and Condition 2-49
2.7 REFERENCES 2-53

3 EMISSIONS AND ENGINEERING COSTS 3-1

3.1 INTRODUCTION 3-1
3.2 EMISSIONS POINTS, CONTROLS, AND ENGINEERING COSTS ANALYSIS 3-1
3.2.1 Emission Points and Pollution Controls assessed in the RIA 3-2
3.2.1.1 NSPS Emission Points and Pollution Controls 3-2
3.2.1.2 NESHAP Emission Points and Pollution Controls 3-6
3.2.2 Engineering Cost Analysis 3-7

3.2.2.1 NSPS Sources ... 3-8
3.2.2.2 NESHAP Sources ... 3-25
3.3 REFERENCES ... 3-26

4 BENEFITS OF EMISSIONS REDUCTIONS ... 4-1

4.1 INTRODUCTION ... 4-1
4.2 DIRECT EMISSION REDUCTIONS FROM THE OIL AND NATURAL GAS RULES ... 4-2
4.3 SECONDARY IMPACTS ANALYSIS FOR OIL AND GAS RULES ... 4-4
4.4 HAZARDOUS AIR POLLUTANT (HAP) BENEFITS ... 4-8
4.4.1 Benzene ... 4-13
4.4.2 Toluene ... 4-15
4.4.3 Carbonyl sulfide ... 4-15
4.4.4 Ethylbenzene ... 4-16
4.4.5 Mixed xylenes ... 4-17
4.4.6 n-Hexane ... 4-17
4.4.7 Other Air Toxics ... 4-18
4.5 VOCs ... 4-18
4.5.1 VOCs as a PM2.5 precursor ... 4-18
4.5.2 $PM_{2.5}$ health effects and valuation ... 4-19
4.5.3 Organic PM welfare effects ... 4-23
4.5.4 Visibility Effects ... 4-24
4.6 VOCS AS AN OZONE PRECURSOR ... 4-24
4.6.1 Ozone health effects and valuation ... 4-25
4.6.2 Ozone vegetation effects ... 4-26
4.6.3 Ozone climate effects ... 4-26
4.7 METHANE (CH_4) ... 4-27
4.7.1 Methane as an ozone precursor ... 4-27
4.7.2 Methane climate effects and valuation ... 4-27
4.8 REFERENCES ... 4-34

5 STATUTORY AND EXECUTIVE ORDER REVIEWS ... 5-1

5.1 EXECUTIVE ORDER 12866, REGULATORY PLANNING AND REVIEW AND EXECUTIVE ORDER 13563, IMPROVING REGULATION AND REGULATORY REVIEW ... 5-1
5.2 PAPERWORK REDUCTION ACT ... 5-3
5.3 REGULATORY FLEXIBILITY ACT ... 5-4
5.3.1 Proposed NSPS ... 5-5
5.3.2 Proposed NESHAP Amendments ... 5-5
5.4 UNFUNDED MANDATES REFORM ACT ... 5-6
5.5 EXECUTIVE ORDER 13132: FEDERALISM ... 5-6
5.6 EXECUTIVE ORDER 13175: CONSULTATION AND COORDINATION WITH INDIAN TRIBAL GOVERNMENTS ... 5-6
5.7 EXECUTIVE ORDER 13045: PROTECTION OF CHILDREN FROM ENVIRONMENTAL HEALTH RISKS AND SAFETY RISKS ... 5-7
5.8 EXECUTIVE ORDER 13211: ACTIONS CONCERNING REGULATIONS THAT SIGNIFICANTLY AFFECT ENERGY SUPPLY, DISTRIBUTION, OR USE ... 5-7
5.9 NATIONAL TECHNOLOGY TRANSFER AND ADVANCEMENT ACT ... 5-9
5.10 EXECUTIVE ORDER 12898: FEDERAL ACTIONS TO ADDRESS ENVIRONMENTAL JUSTICE IN MINORITY POPULATIONS AND LOW-INCOME POPULATIONS ... 5-10

6 COMPARISON OF BENEFITS AND COSTS ... 6-1

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS ... 7-1

7.1 INTRODUCTION ... 7-1
7.2 ENERGY SYSTEM IMPACTS ANALYSIS OF PROPOSED NSPS ... 7-1
7.2.1 Description of the Department of Energy National Energy Modeling System ... 7-2
7.2.2 Inputs to National Energy Modeling System ... 7-5

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production 7-6
7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production 7-9
7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path 7-10
7.2.3 Energy System Impacts 7-11
7.2.3.1 Impacts on Drilling Activities 7-11
7.2.3.2 Impacts on Production, Prices, and Consumption 7-13
7.2.3.3 Impacts on Imports and National Fuel Mix 7-17
7.3 EMPLOYMENT IMPACT ANALYSIS 7-20
7.3.1 Employment Impacts from Pollution Control Requirements 7-21
7.3.2 Employment Impacts Primarily on the Regulated Industry 7-24
7.4 SMALL BUSINESS IMPACTS ANALYSIS 7-28
7.4.1 Small Business National Overview 7-29
7.4.2 Small Entity Economic Impact Measures 7-34
7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS 7-36
7.4.3.1 Overview of Sample Data and Methods 7-36
7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results 7-42
7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion 7-48
7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion 7-51
7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments 7-52
7.5 REFERENCES 7-54

LIST OF TABLES

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1] ... 1-4
Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1] ... 1-6
Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007 ... 2-10
Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008 ... 2-11
Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008 ... 2-13
Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price 2-14
Table 2-5 Natural Gas Production and Well Productivity, 1990-2009 ... 2-15
Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009 . 2-17
Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007 ... 2-18
Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008 ... 2-20
Table 2-9 Crude Oil Consumption by Sector, 1990-2009 ... 2-21
Table 2-10 Natural Gas Consumption by Sector, 1990-2009 ... 2-23
Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009 ... 2-25
Table 2-12 Natural Gas Imports and Exports, 1990-2009 ... 2-26
Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035 ... 2-27
Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035 ... 2-29
Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price ... 2-31
Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms ... 2-38
Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09 ... 2-39
Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars) ... 2-43
Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010 ... 2-47
Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009 ... 2-48
Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009 ... 2-49
Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars) ... 2-50
Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent) ... 2-51
Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars) ... 2-52
Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options ... 3-9
Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points ... 3-15
Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015 ... 3-16
Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$) ... 3-18
Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015 ... 3-21
Table 3-6 Simple Rate of Return Estimate for NSPS Control Options ... 3-23
Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments ... 3-26
Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year) ... 4-3
Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category (“Producer-Side”) (tons per year) ... 4-6
Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1] ... 4-7
Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ... 4-7
Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year) ... 4-8
Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$) ... 4-22
Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1] ... 5-2

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1] ... 6-4
Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1] ... 6-5
Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year) ... 6-6
Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS ... 7-8
Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS ... 7-9
Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options ... 7-11
Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options ... 7-12
Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options ... 7-13
Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options ... 7-15
Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options ... 7-16
Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options ... 7-16
Table 7-9 Natural Gas Consumption by Sector, NSPS Options ... 7-17
Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options ... 7-18
Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options ... 7-19
Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions ... 7-20
Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015 ... 7-26
Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015 ... 7-27
Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007 ... 7-31
Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007 ... 7-32
Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009 ... 7-34
Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size ... 7-38
Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars) ... 7-39
Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars) ... 7-40
Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms ... 7-43
Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms ... 7-44
Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS ... 7-45
Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS ... 7-46
Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery ... 7-47
Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments ... 7-53
Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments ... 7-53

LIST OF FIGURES

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008 2-12
Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009..... 2-16
Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007..... 2-19
Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009..... 2-22
Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009 2-24
Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035 2-28
Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035..... 2-30
Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008 2-32
Figure 2-9 Finding Costs for FRS Companies, 1981-2008..... 2-33
Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)2-34
Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009 2-35
Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009 2-36
Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009..... 2-40
Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009..... 2-41
Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009... 2-42
Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)..... 2-44
Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included..... 3-19
Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments... 4-5
Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA) 4-10
Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA) 4-11
Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS..... 6-2
Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration) 7-4

1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion

of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20° or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural

underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40° or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the

surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling

is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

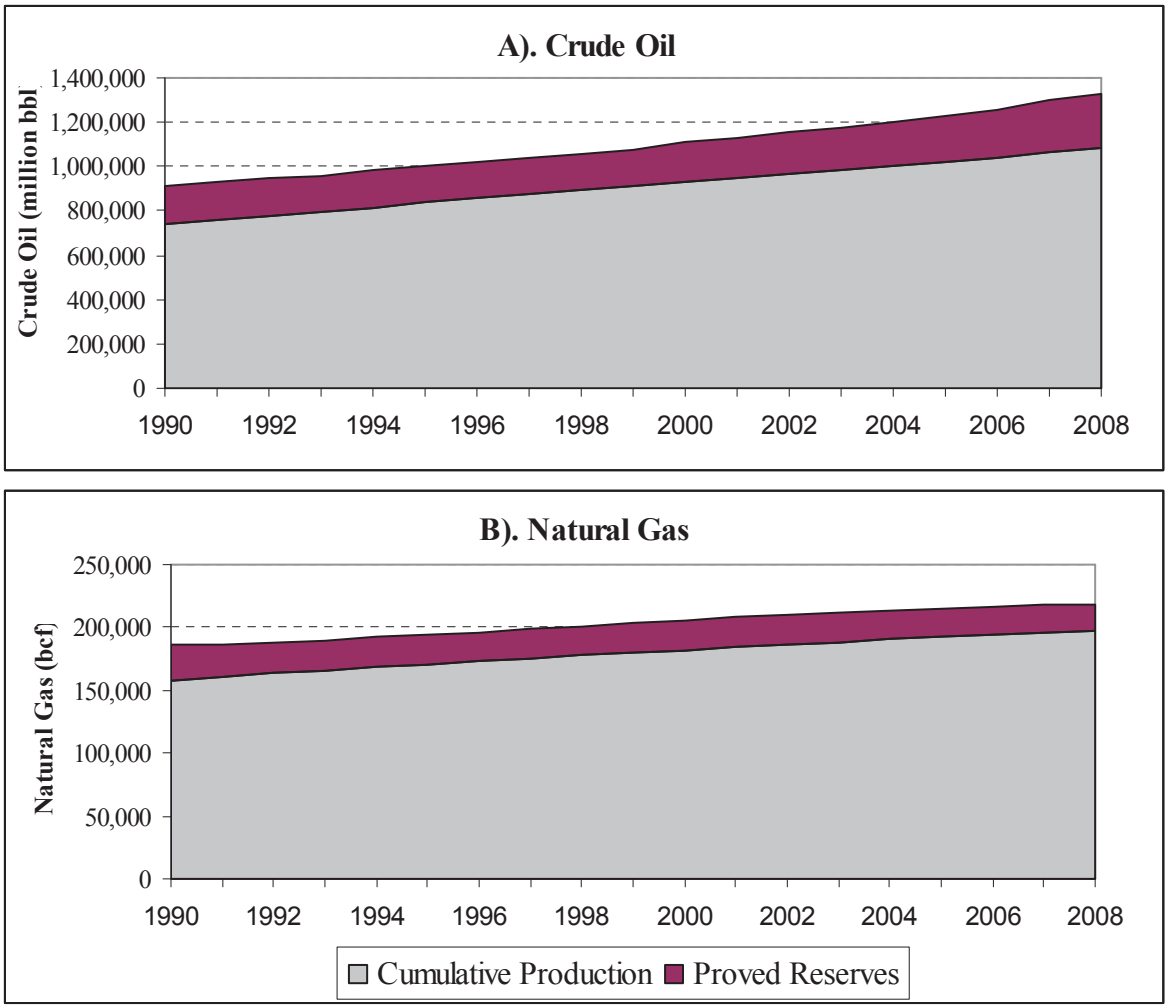


Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

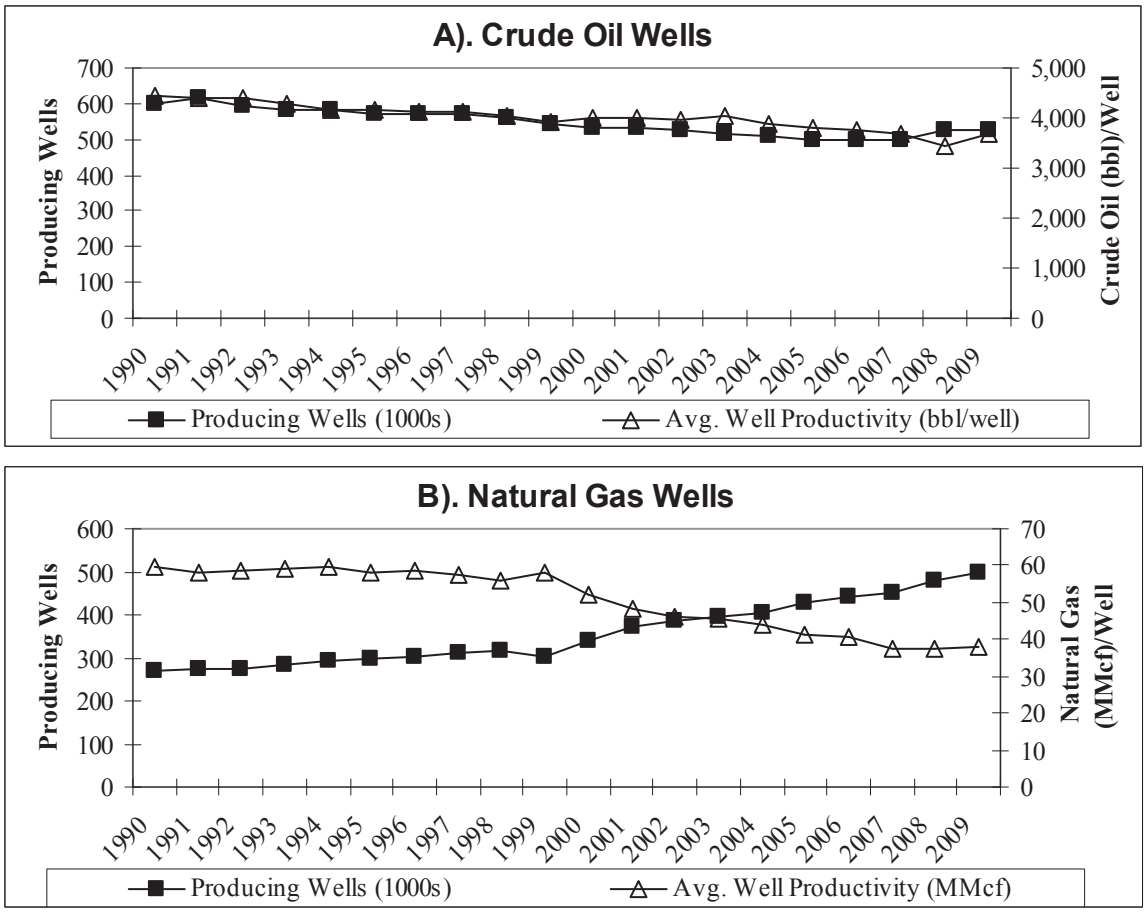


Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in

well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

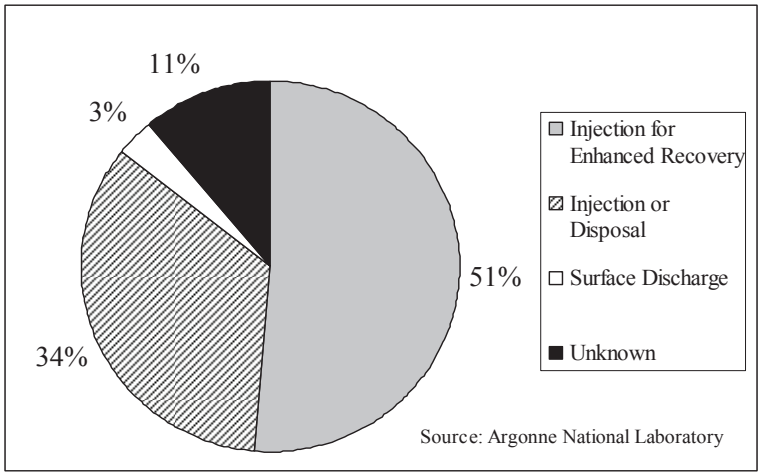


Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added

about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

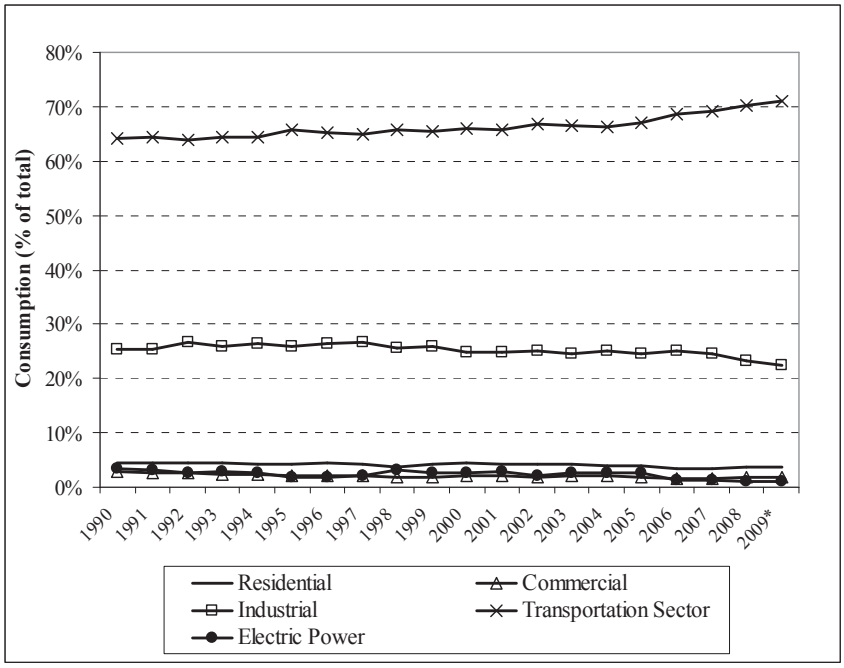


Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total				
		Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

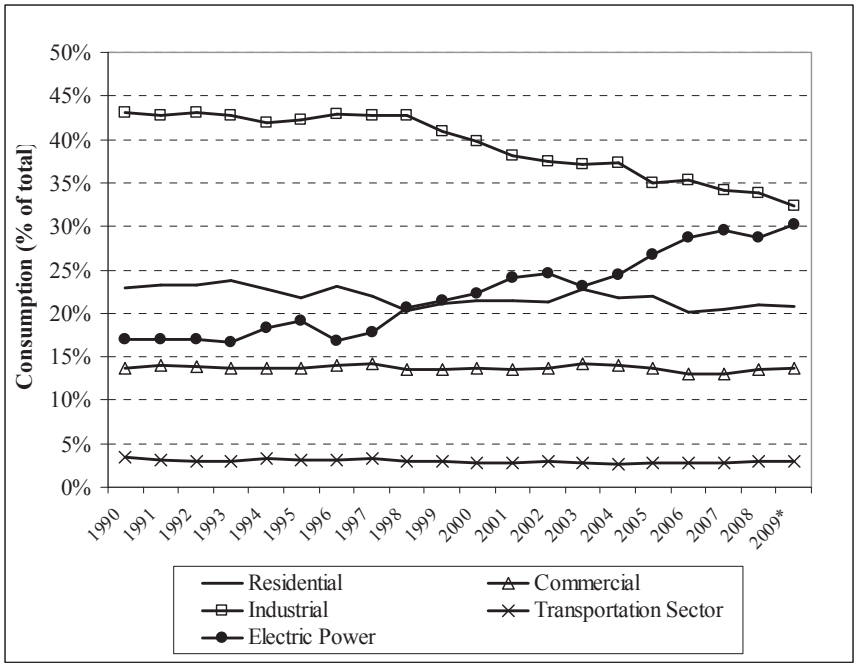


Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

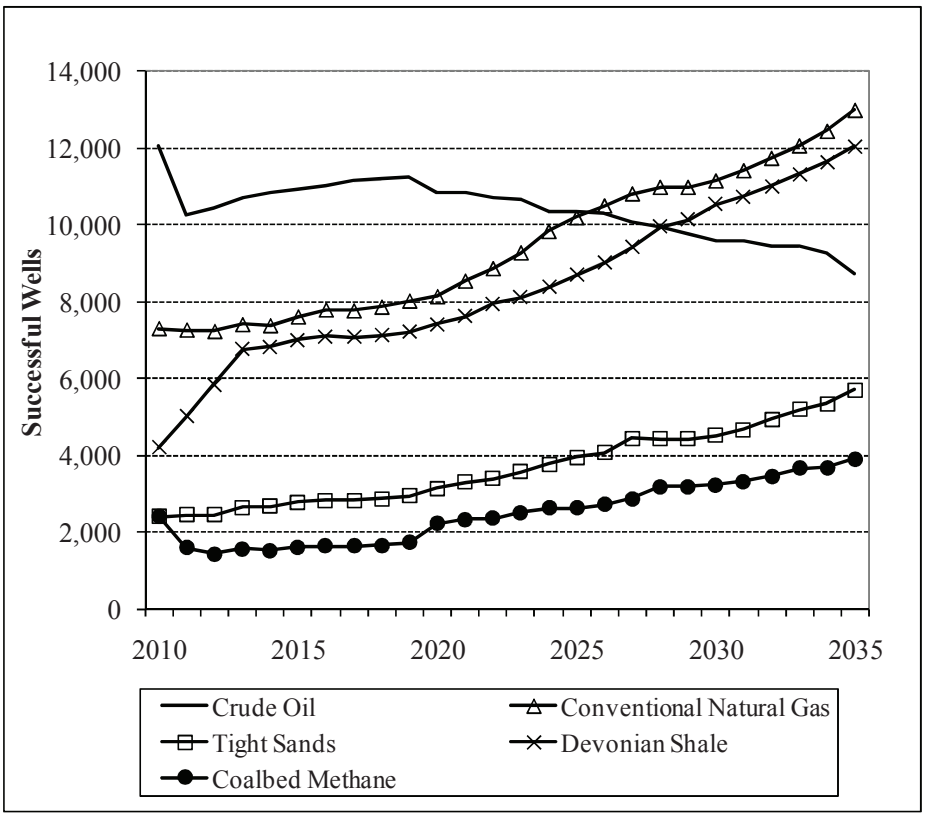


Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also

shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

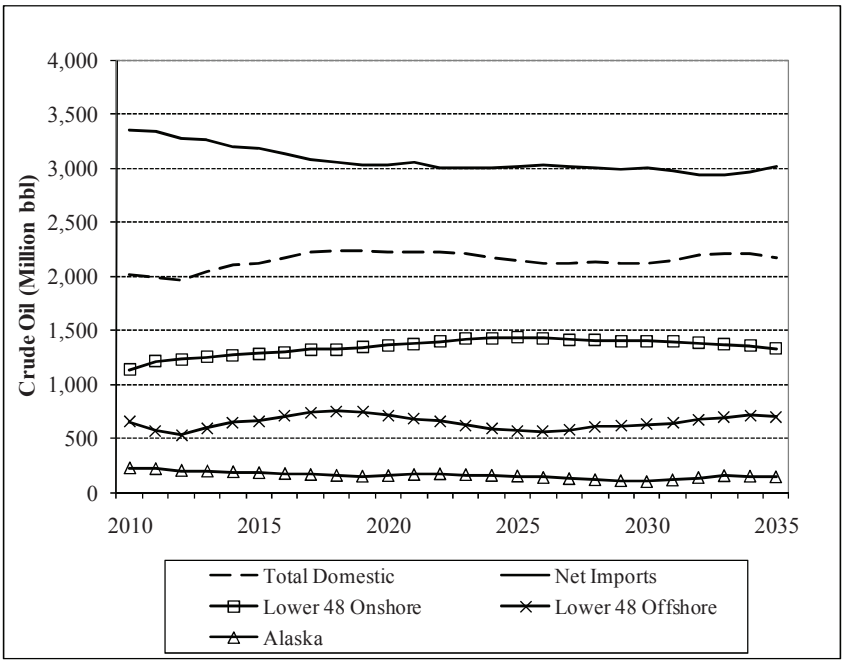


Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

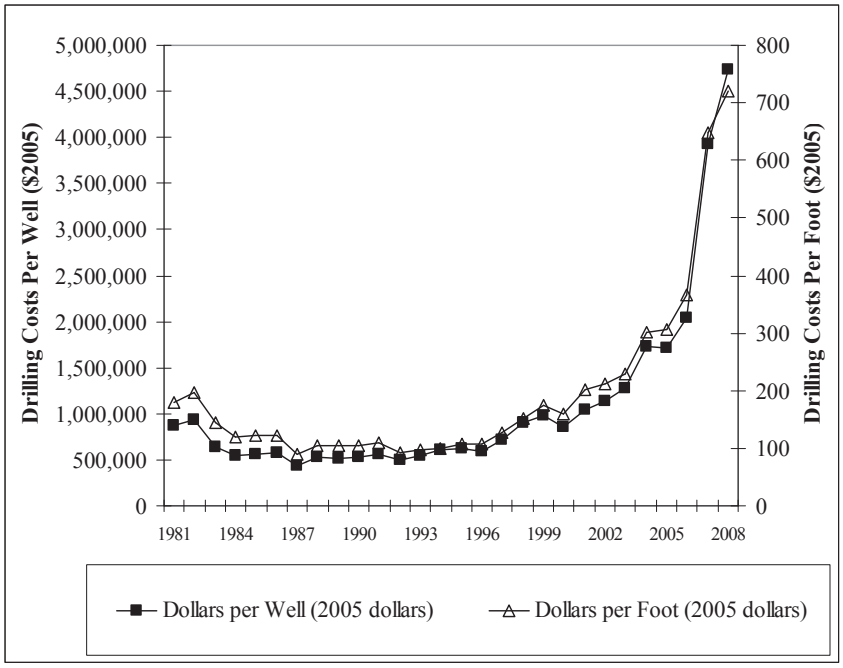


Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

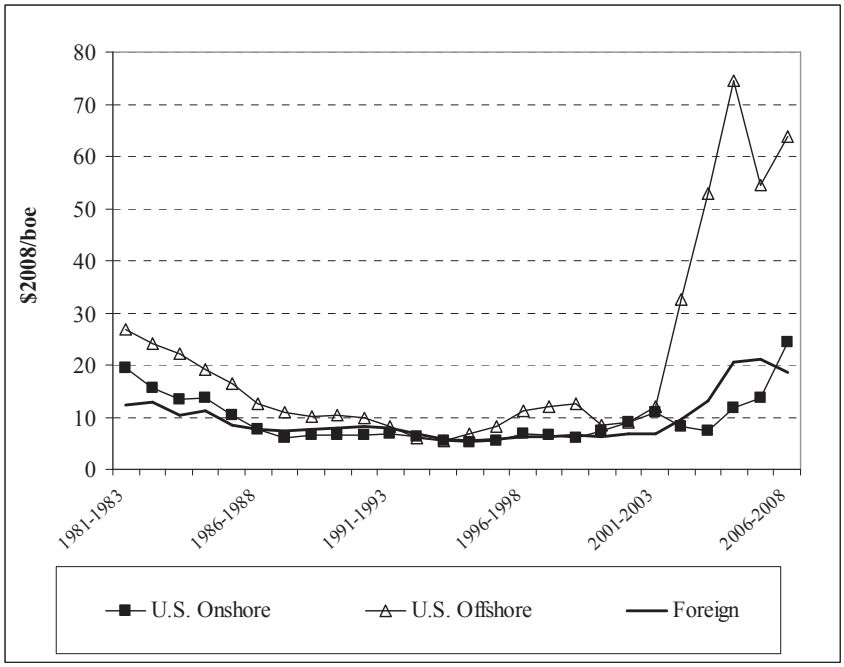


Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

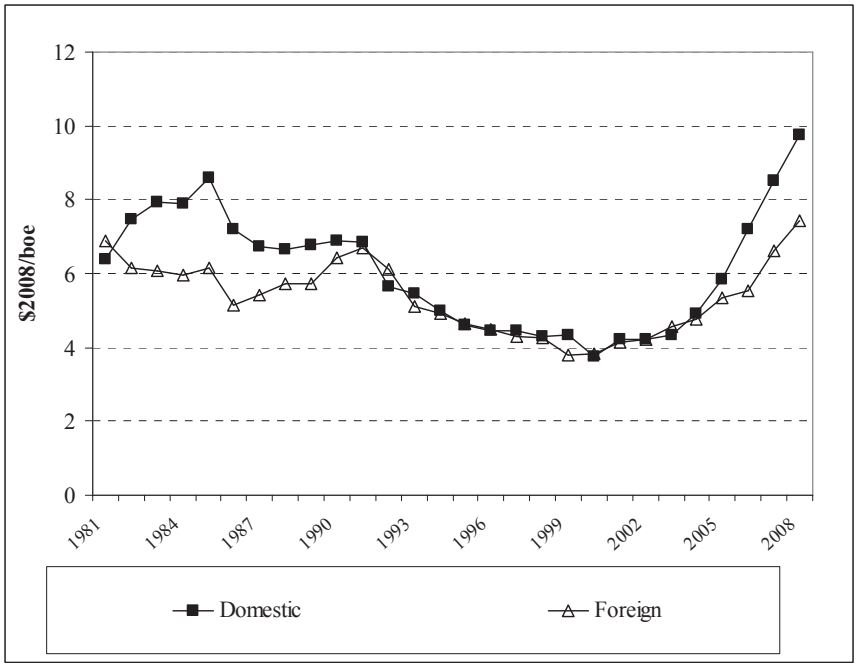


Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

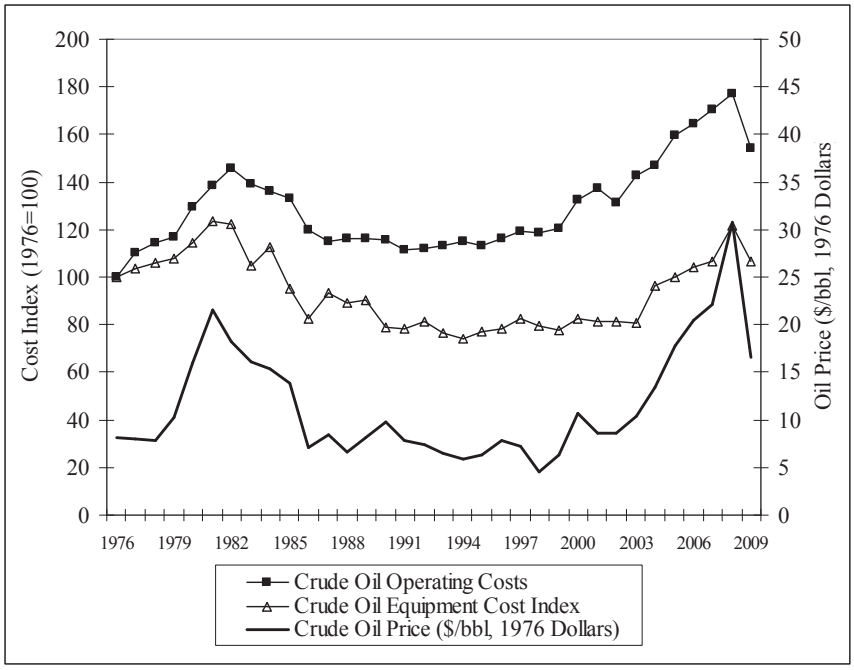


Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

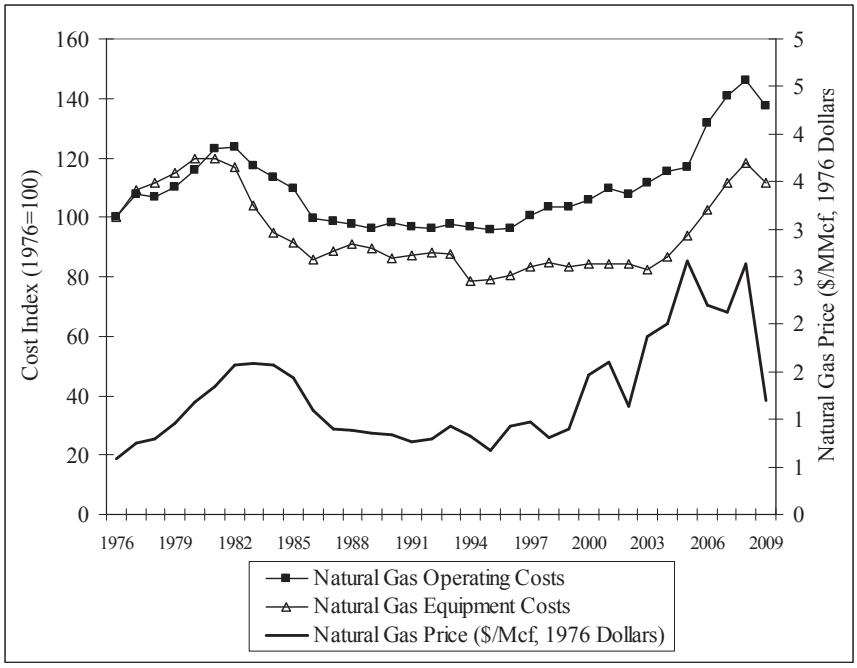


Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies

that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

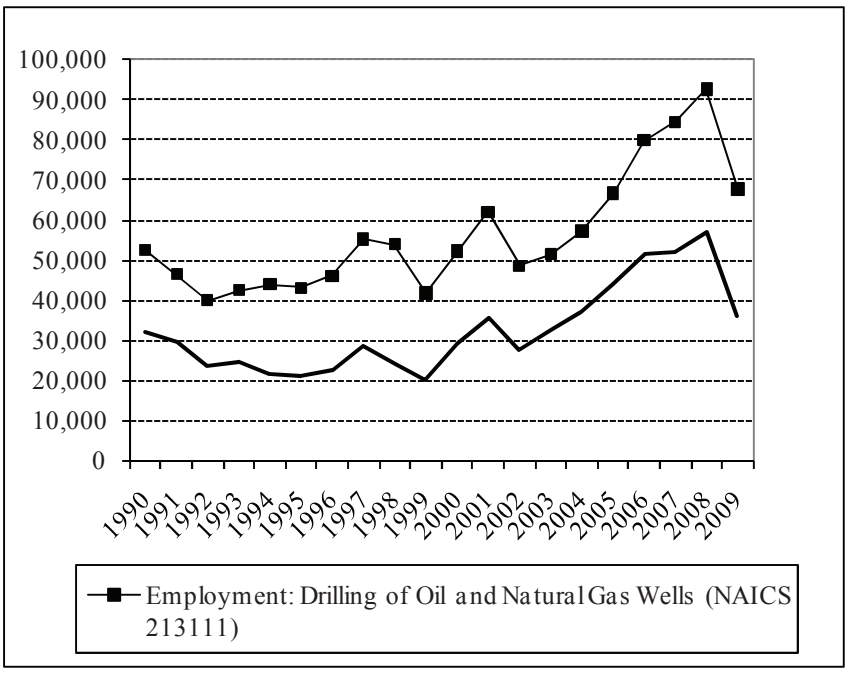


Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

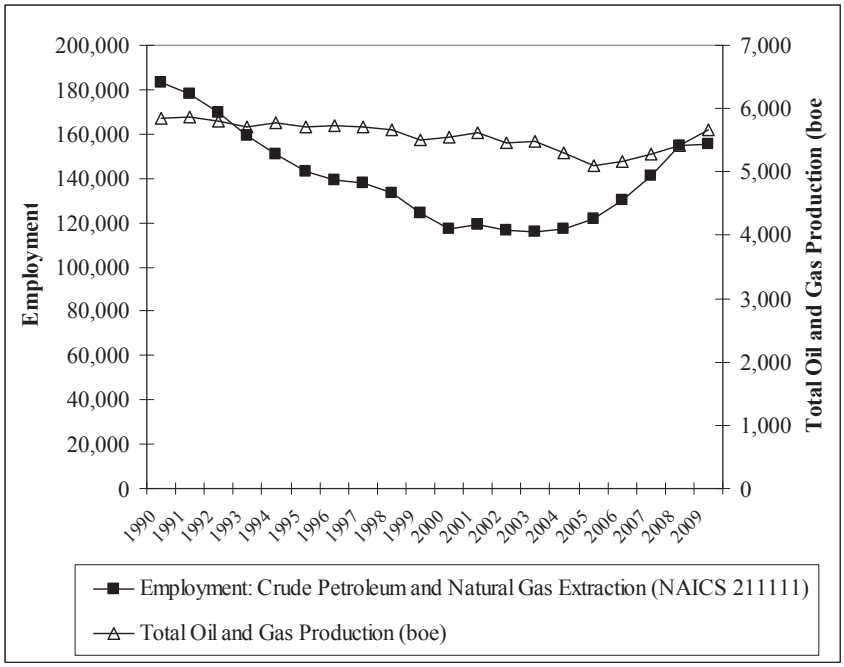


Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

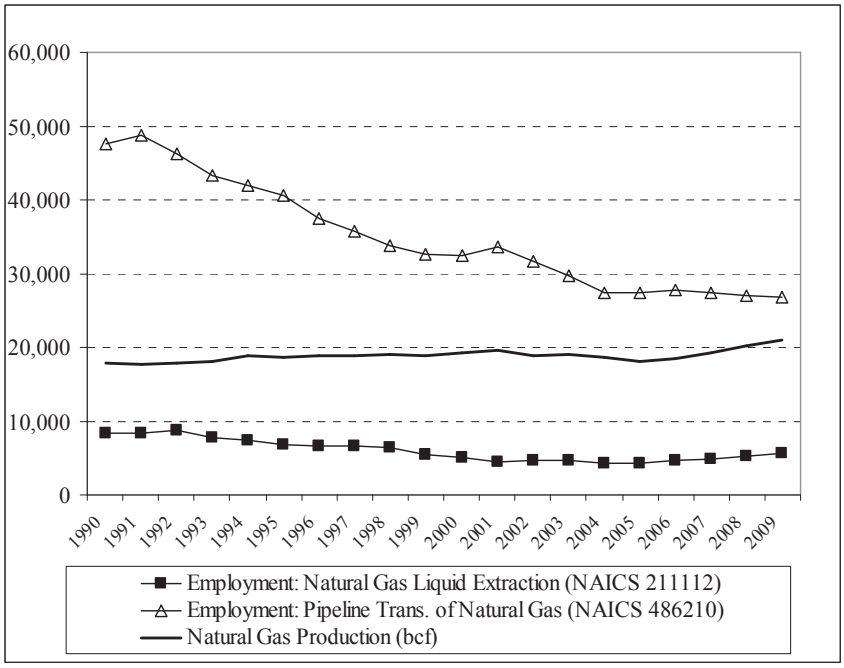


Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

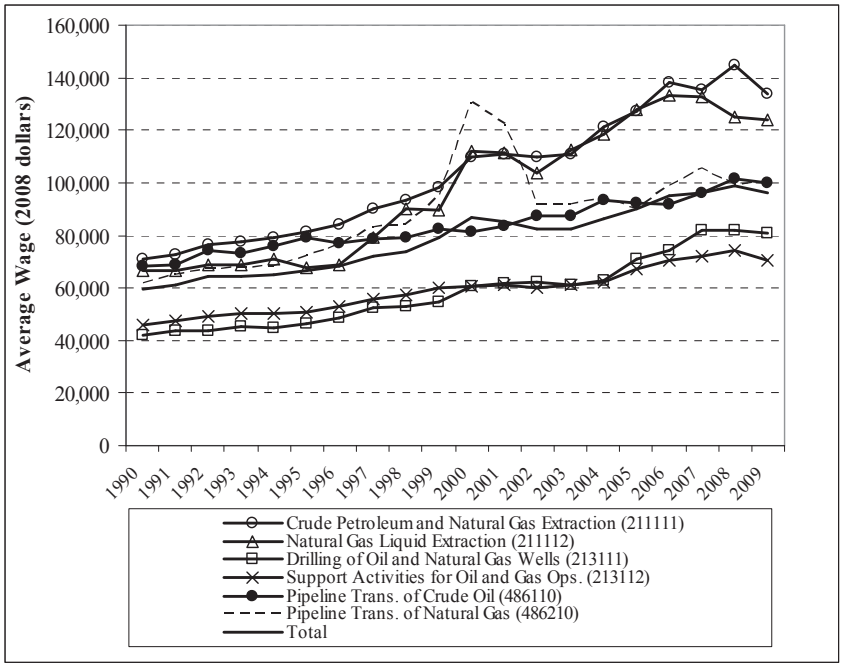


Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which

only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production		U.S. Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the

top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

2.7 References

Andrews, et al. 2009. Unconventional Gas Shales: Development, Technology, and Policy Issues. Congressional Research Service. R40894.

Argonne National Laboratory. 2009. Produced Water Volumes and Management Practices in the United States. ANL/EVS/R-09/1.

Hyne, N.J. 2001. *Nontechnical Guide to Petroleum Geology, Exploration, Drilling and Production.* Tulsa, OK: Penwell Books.

Independent Petroleum Association of America. 2009. Profile of Independent Producers. <http://www.ipaa.org/news/docs/IPAAProfile2009.pdf> Accessed March 30, 2011.

Manning, F.S. and R.E. Thompson. 1991. *Oil Field Processing of Petroleum – Volume 3: Produced and Injection Waters*. Tulsa, OK: Penn Well Books.

Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.

U.S. Energy Information Administration (U.S. EIA). 2006. Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf> Accessed February 2, 2011.

U.S. Department of Energy. 2009. Modern Shale Gas Development in the United States: A Primer. <http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf> Accessed March 30, 2011.

U.S. Energy Information Administration (U.S. EIA). 2010. Annual Energy Review (AER). <http://www.eia.doe.gov/emeu/aer/contents.html>

U.S. Energy Information Administration (U.S. EIA). 2010. Oil and Gas Lease Equipment and Operating Costs 1994 through 2009 <http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed March 30, 2011.

U.S. Energy Information Administration (U.S. EIA). 2010. Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves 2009. <http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html> Accessed March 30, 2011.

U.S. Energy Information Administration (U.S. EIA). 2010. Performance Profiles of Major Energy Producers 2008. <http://www.eia.gov/finance/performanceprofiles> Accessed March 30, 2011.

U.S. Energy Information Administration (U.S. EIA). 2011. Annual Energy Outlook 2011. <http://www.eia.gov/forecasts/aeo> June 2, 2011.

U.S. Environmental Protection Agency (U.S. EPA), Office of Air Quality Planning and Standards. 1996. Economic Analysis of Air Pollution Regulations: Oil and Natural Gas Production. <http://www.epa.gov/ttnecas1/regdata/IPs/Oil%20and%20NG%20Production%20and%20NG%20Transmission_IP.pdf> Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2004. Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. EPA/816-R-04-003.

U.S. Environmental Protection Agency. 2000. EPA Office of Compliance Sector Notebook Project: Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. <http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oil.html> Accessed March 30, 2011.

3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors,

referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil

and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of

working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate

that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader's understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	X	X	X
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	X	X	X
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	X	X	X
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		X	X
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			X
Gathering and Boosting Stations	NSPS Subpart VV			X
Processing Plants	NSPS Subpart VVa		X	X
Transmission Compressor Stations	NSPS Subpart VV			X
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	X	X	X
Processing Plants	AMM	X	X	X
Transmission Compressor Stations	AMM	X	X	X
Underground Storage Facilities	AMM	X	X	X
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	X	X	X
Transmission Compressor Stations	Dry Seals/Route to Process or Control	X	X	X
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	X	X	X
Natural Gas Transmission and Storage	Low Bleed/Route to Process	X	X	X
Storage Vessels				
High Throughput	95% control	X	X	X
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions

that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions

reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$) Without Revenues from Additional Product Recovery	Per Unit Annualized Cost (2008$) With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	Emissions Control	Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	Emissions Control	Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead

for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

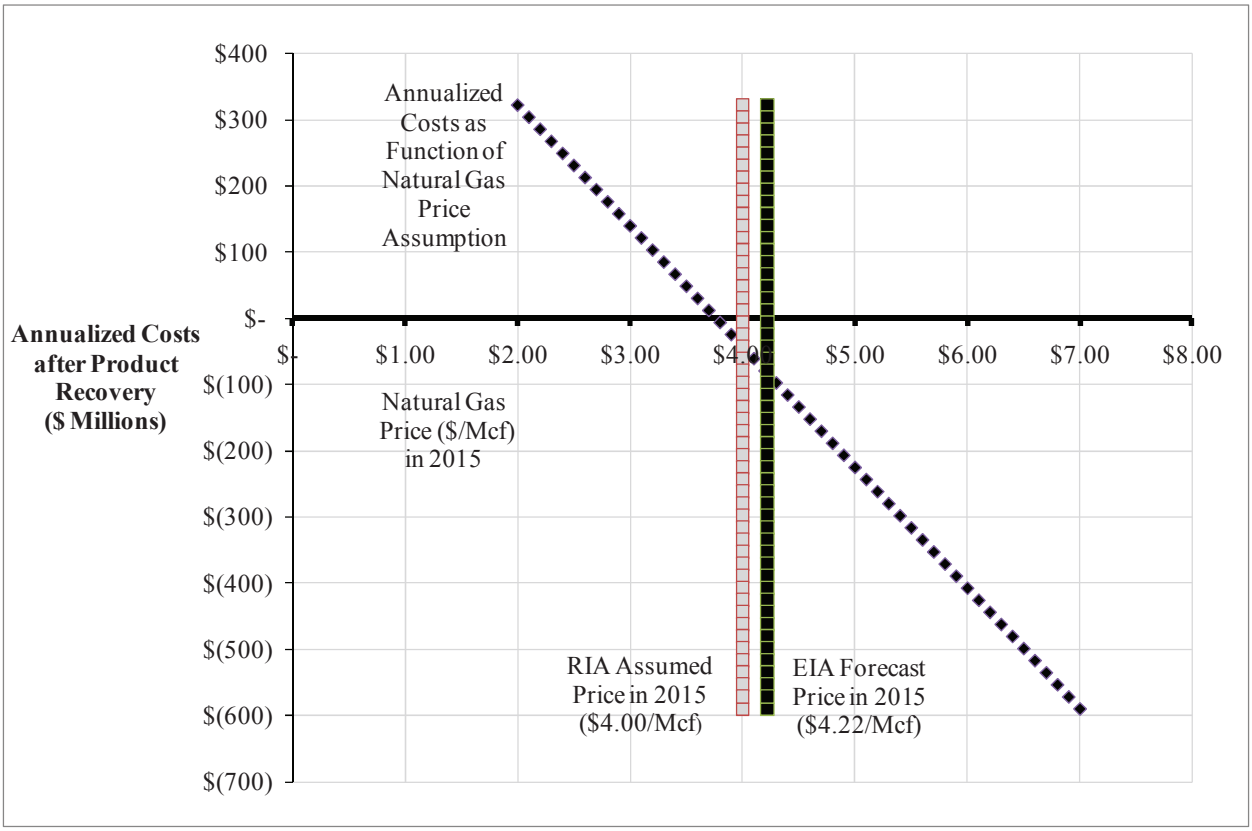


Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery		Total Product Recovery	
				Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware

of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the

engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annualized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year)			HAP Reduction Cost-Effectiveness (2008$/ton)
					HAP	VOC	Methane	
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Oil and Gas Journal. "OGJ150." September 21, 2009.

Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates

for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

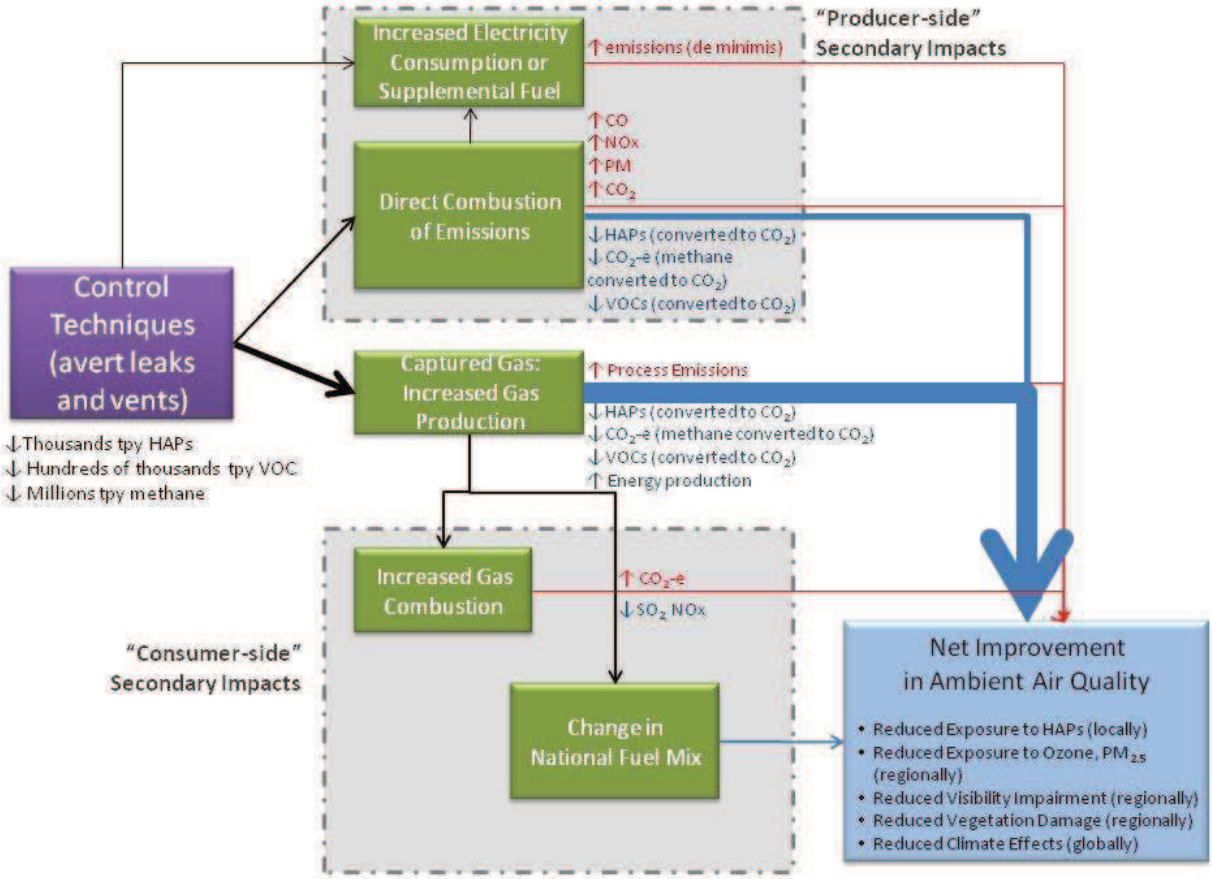


Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually

lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	**NSPS Option 1**	**NSPS Option 2 (Proposed)**	**NSPS Option 3**	**NESHAP Amendments**
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

---

[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

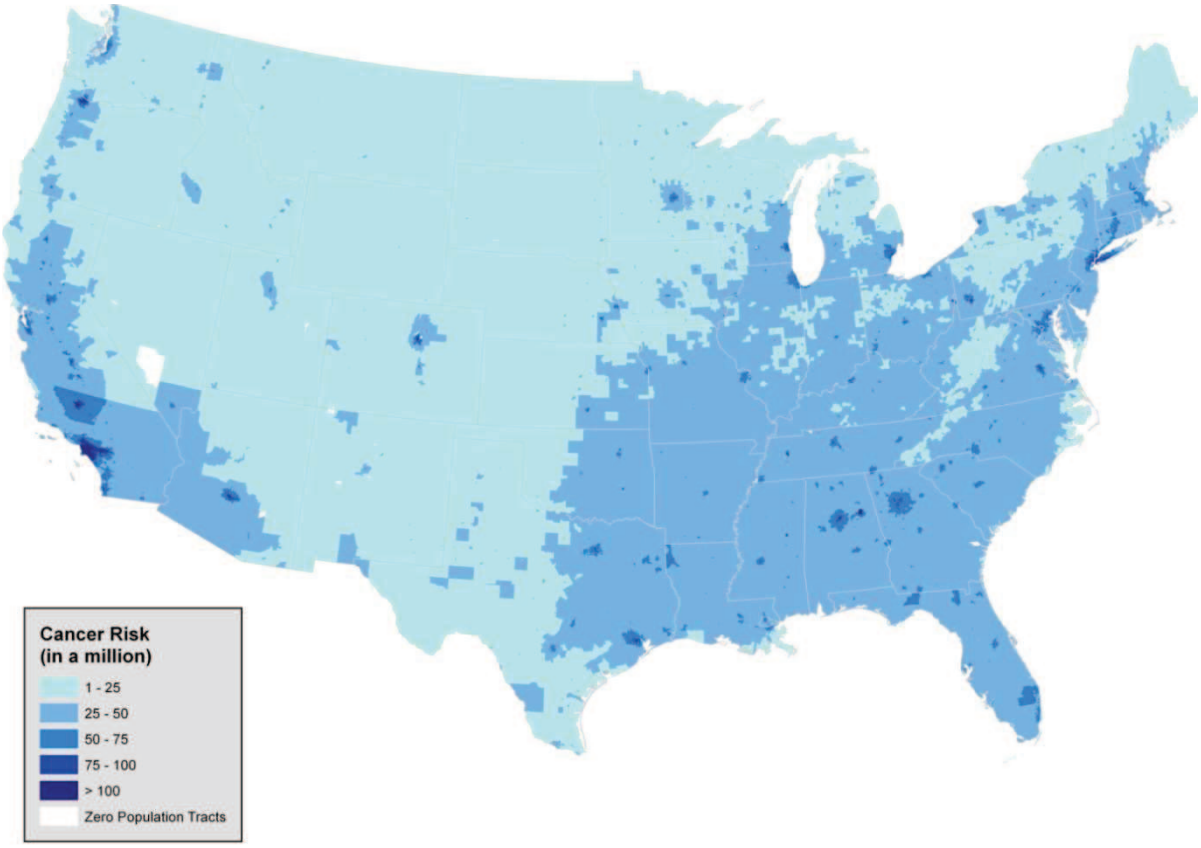


Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

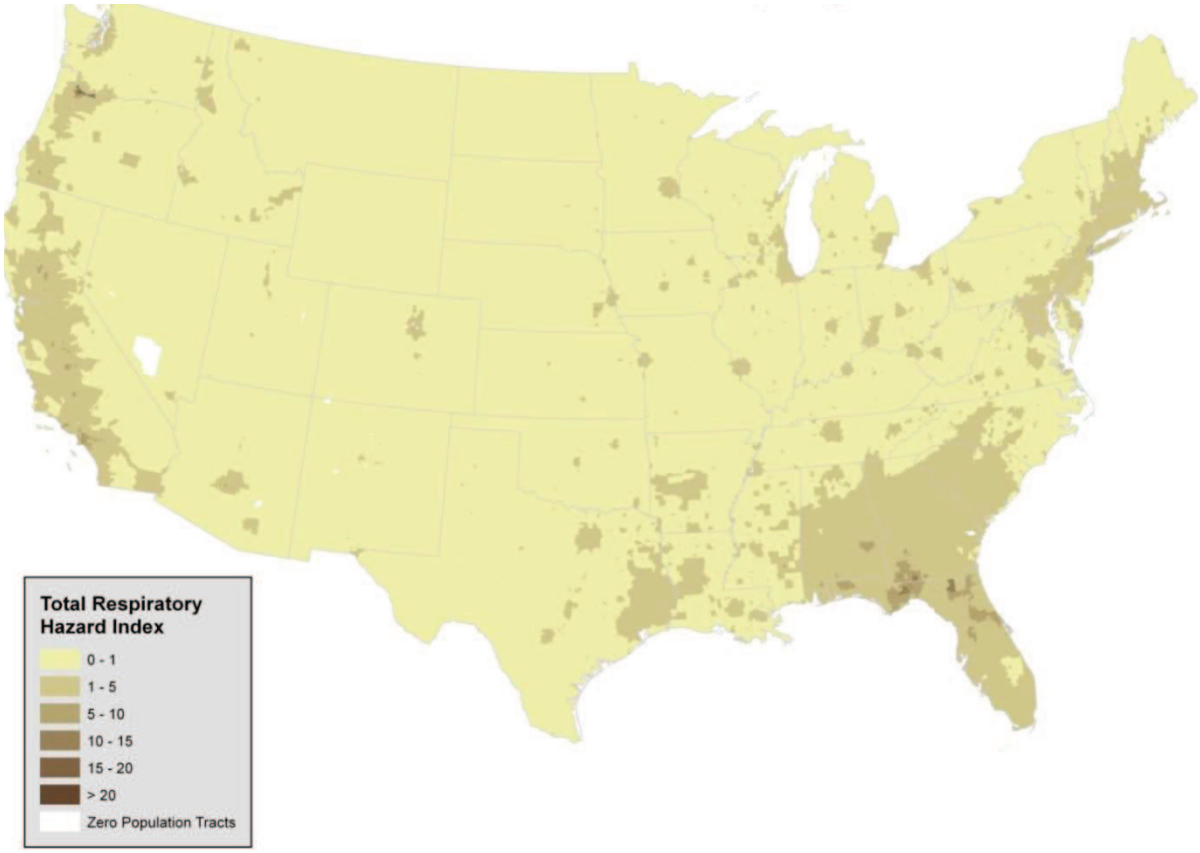


Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

---

[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 Toluene[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

---

[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

---

[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5}$. Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 Organic PM welfare effects

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is

counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC

emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to "trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss" (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to

protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 (MMtCO_2-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 MMtCO_2-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 MMtCO_2-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 MMTCO_2-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are

equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: $6, $25, $40, and $76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is

typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of

having no interagency accepted monetary values to place on these co-benefits. The 'GWP approach' of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability

of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with 'GWP approach' estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be

used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

4.8 References

Fankhauser, S. 1994. "The social costs of greenhouse gas emissions: an expected value approach." *Energy Journal* 15(2):157–184.

Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." *Air Qual Atmos Health* 2:169-176.

Forster, P. et al. 2007. *Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007. The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Gwinn, M.R., J. Craig, D.A. Axelrad, R. Cook, C. Dockins, N. Fann, R. Fegley, D.E. Guinnup, G. Helfand, B. Hubbell, S.L. Mazur, T. Palma, R.L. Smith, J. Vandenberg, and B. Sonawane. 2011. "Meeting report: Estimating the benefits of reducing hazardous air pollutants—summary of 2009 workshop and future considerations." *Environ Health Perspect*. 119(1): p. 125-30.

Hammitt, J.K., A.K. Jain, J.L. Adams, and D.J. Wuebbles. 1996. "A welfare-based index for assessing environmental effects of greenhouse-gas emissions." *Nature*, 381(6580):301–303, 1996.

Hope, C. 2005. "The climate change benefits of reducing methane emissions." *Climatic Change* 68(1):21–39.

Hope, C. and D. Newbery. 2006. "Calculating the Social Cost of Carbon" Forthcoming in Delivering a Low Carbon Electricity System: Technologies, Economics and Policy Editors: Michael Grubb, Tooraj Jamasb and Michael G. Pollitt (University of Cambridge) Cambridge University Press. Available on the Internet at <http://www.dspace.cam.ac.uk/handle/1810/194738> Accessed March 30, 2011.

Industrial Economics, Inc (IEc). 2009. *Section 812 Prospective Study of the Benefits and Costs of the Clean Air Act: Air Toxics Case Study—Health Benefits of Benzene Reductions in Houston, 1990–2020. Final Report*, July 14, 2009. <http://www.epa.gov/air/sect812/dec09/812CAAA_Benzene_Houston_Final_Report_July_2009.pdf>. Accessed March 30, 2011.

Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. T*echnical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* Docket ID EPA-HQ-OAR-2009-0472-114577. Participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury. <http://www.epa.gov/otaq/climate/regulations.htm> Accessed March 30, 2011.

Intergovernmental Panel on Climate Change (IPCC). 2007. *Climate Change 2007: Synthesis Report.* Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (AR4) [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]. IPCC, Geneva, Switzerland, 104 pp. <http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm>. Accessed March 30, 2011/

Intergovernmental Panel on Climate Change (IPCC). 2007. IPCC Fourth Assessment Report: Climate Change 2007. Working Group II, Chapter 20 'Perspectives on Climate Change and Sustainability.' <http://www.ipcc.ch/publications_and_data/ar4/wg2/en/ch20s20-6-1.html> Accessed March 30, 2011.

Kandlikar, M. 1995. "The relative role of trace gas emissions in greenhouse abatement policies." *Energy Policy* 23(10): 879–883.

Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine* 173:667-672.

Landers DH; Simonich SL; Jaffe DA; Geiser LH; Campbell DH; Schwindt AR; Schreck CB; Kent ML; Hafner WD; Taylor HE; Hageman KJ; Usenko S; Ackerman LK; Schrlau JE; Rose NL; Blett TF; Erway MM. 2008. *The Fate, Transport and Ecological Impacts of Airborne Contaminants in Western National Parks (USA)*. EPA/600/R-07/138. U.S. Environmental Protection Agency, Office of Research and Development, NHEERL, Western Ecology Division. Corvallis, Oregon.

Marten, A. and S. Newbold. 2011. "Estimating the Social Cost of Non-CO_2 GHG Emissions: Methane and Nitrous Oxide." *NCEE Working Paper Series* # 11-01. <http://yosemite.epa.gov/ee/epa/eed.nsf/WPNumber/2011-01?opendocument>. Accessed March 30, 2011.

Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287:1132-1141.

Roman, H.A., K.D. Walker, T.L. Walsh, L. Conner, H.M. Richmond, .J. Hubbell, and P.L. Kinney. 2008. "Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S." *Environ. Sci. Technol*. 42(7):2268-2274.

Task Force on Hemispheric Transport of Air Pollution (HTAP). 2010. *Hemispheric Transport of Air Pollution 2010*. Informal Document No.10. Convention on Long-range Transboundary Air Pollution Executive Body 28th Session. ECE/EB.AIR/2010/10 (Corrected). Chapter 4, pp. 148-149.

Tol, R. (2006). NEEDS Project 502687 'New Energy Externalities Developments for Sustainability Integrated Project' < http://www.needs-project.org/RS1b/NEEDS_RS1B_TP_T5.4_T5.5.pdf>. Accessed March 30, 2011.

Tol, R, R.J. Heintz, and P.E.M. Lammers. 2003. "Methane emission reduction: An application of FUND." *Climatic Change* 57(1):71–98.

U.S. Environmental Protection Agency (U.S. EPA). 2006a. *Air Quality Criteria for Ozone and Related Photochemical Oxidants* (Final). EPA/600/R-05/004aF-cF. Washington, DC: U.S. EPA. <http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2006b. *Regulatory Impact Analysis, 2006 National Ambient Air Quality Standards for Particulate Matter*, Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. <http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205--Benefits.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 1995. *Regulatory Impact Analysis for the Petroleum Refinery NESHAP. Revised Draft for Promulgation*. Office of Air Quality Planning and Standards, Research Triangle Park, N.C. <http://www.reg-markets.org/admin/authorpdfs/page.php?id=705>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2009a. *Integrated Science Assessment for Particulate Matter* (Final Report). EPA-600-R-08-139F. National Center for Environmental Assessment—RTP Division. <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2009b. *Technical Support Document for Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act*. <http://www.epa.gov/climatechange/endangerment/downloads/Endangerment%20TSD.pd>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2010a. *Regulatory Impact Analysis, National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. <http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2011b. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.* EPA 430-R-11-005. Office of Atmospheric Programs, Washington, DC. <http://epa.gov/climatechange/emissions/usinventory.html >. Accessed July 21, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2010c. *Regulatory Impact Analysis for the Proposed Federal Transport Rule.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. <http://www.epa.gov/ttn/ecas/regdata/RIAs/proposaltrria_final.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2010d. *Regulatory Impact Analysis for the SO_2 NAAQS.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. < http://www.epa.gov/ttn/ecas/regdata/RIAs/fso2ria100602full.pdf>. Accessed March 30, 2011.

U.S Environmental Protection Agency (U.S. EPA). 2011a. *Draft Residual Risk Assessment for the Oil and Natural Gas Source Category.* Office of Air Quality Planning and Standards. Office of Air and Radiation.

U.S. Environmental Protection Agency (U.S. EPA). 2010e. 40 CFR Part 98 Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems; Final Rule. Federal Register Vol. 75, No. 229, November 30, 2010. 74458-74515. <http://edocket.access.gpo.gov/2010/pdf/2010-28655.pdf> Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2010f. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. Federal Register Vol. 75, No. 106, June 3, 2010. 31514-31608 <http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1> Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2011a. *The Benefits and Costs of the Clean Air Act from 1990 to 2020*. Office of Air and Radiation, Washington, DC. March. <http://www.epa.gov/air/sect812/feb11/fullreport.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2011b. *Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. February. <http://www.epa.gov/ttn/ecas/regdata/RIAs/boilersriafinal110221_psg.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2011c. *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. April.

U.S. Environmental Protection Agency (U.S. EPA). 2011d. *2005 National-Scale Air Toxics Assessment.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. March. < http://www.epa.gov/ttn/atw/nata2005/> Accessed March 30, 2011.

U.S. Environmental Protection Agency (U.S. EPA). 2011e. *Draft Inventory of the U.S. Greenhouse Gas Emissions and Sinks 1990.* Report No. 430-R-11-005. February. <http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA-SAB). 2002. *Workshop on the Benefits of Reductions in Exposure to Hazardous Air Pollutants: Developing Best Estimates of Dose-Response Functions An SAB Workshop Report of an EPA/SAB Workshop (Final Report).* EPA-SAB-EC-WKSHP-02-001. January. <http://yosemite.epa.gov/sab%5CSABPRODUCT.NSF/34355712EC011A358525719A005BF6F6/$File/ecwkshp02001%2Bappa-g.pdf>. Accessed March 30, 2011.

U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA-SAB). 2008. *Benefits of Reducing Benzene Emissions in Houston, 1990–2020*. EPA-COUNCIL-08-001. July. <http://yosemite.epa.gov/sab/sabproduct.nsf/D4D7EC9DAEDA8A548525748600728A83/$File/EPA-COUNCIL-08-001-unsigned.pdf>. Accessed March 30, 2011.

West et al. 2006. "Global health benefits of mitigating ozone pollution with methane emission controls." *PNAS* 103:11:3988-3993.

5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year

and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a

population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to

revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance

costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA's risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant

adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are

associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

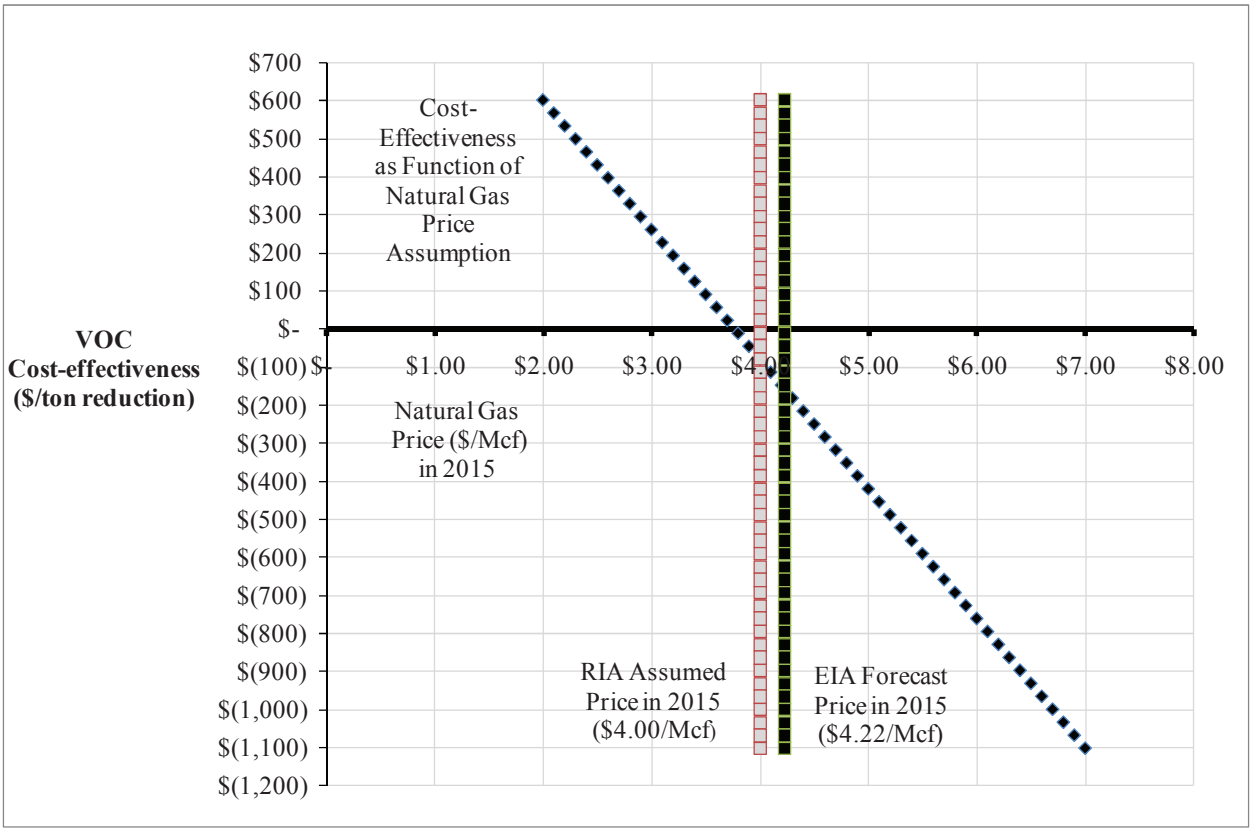


Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits

of VOC emissions are valued at $280 to $7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only $3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are

completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy

economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

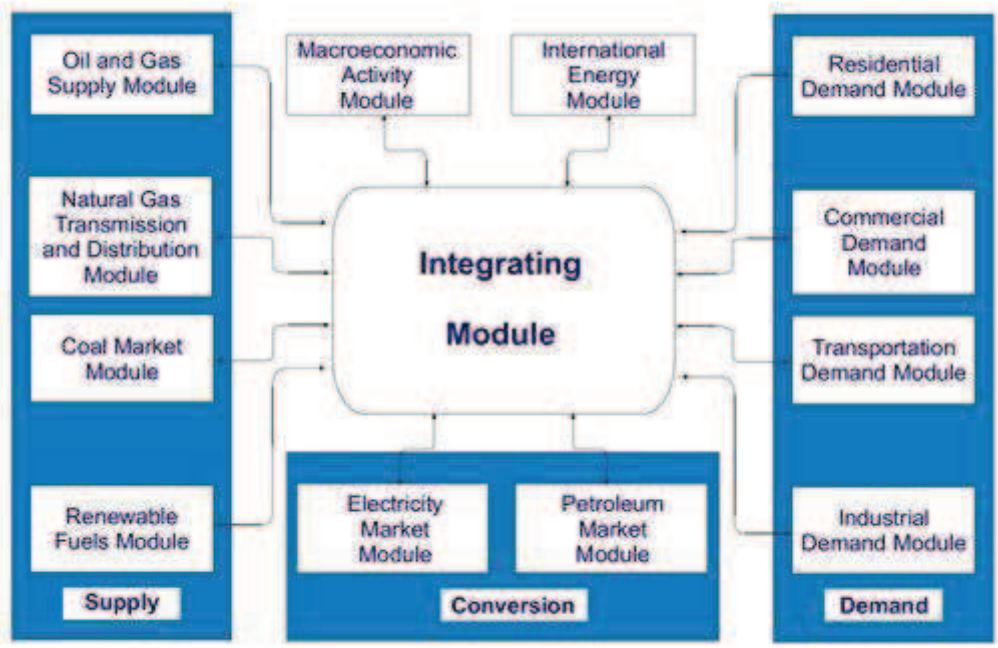


Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of

the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$) Option 1	Option 2 (Proposed)	Option 3	Wells Applied To in NEMS
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an

estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment

leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the

proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related "consumer-side" GHG emissions. We use the terms "consumer-side" emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels "producer-side" emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and

maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate

cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping

requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a

significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishmen*t: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	Owned by Firms with: < 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation's low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

---

[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We

apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by

model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated

revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $5.5 million without estimated revenues from product recovery and $3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery ($740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -$23 million, compared to engineering cost estimate of -$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129

firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular "niche" strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older

equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median

sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

7.5 References

Bezdek, R.H., R.M. Wendling, and P. DiPern**a**. 2008. "Environmental protection, the economy, and jobs: national and regional analyses." *Journal of Environmental Management 86(1):63-79.*

Duda, J.R., G. Covatch, D. Remson, S. Wang. 2005. Projections of marginal wells and their contributions to oil and natural gas supplies. Society of Petroleum Engineers Eastern regional Meeting, SPE98014.

Gabriel, S.A., A.S. Kydes, and P. Whitman. 2001. "The National Energy Modeling System: a large-scale energy-economic equilibrium model." *Operations Research* 49:1: 14-25.

IHS Global Insight. "The Economic Contribution of the Onshore Independent oil and Natural Gas Producers to the U.S. Economy." Prepared for the Independent Petroleum Association of America. April 2011. <http://www.ipaa.org/news/docs/IHSFinalReport.pdf> Accessed July 23, 2011.

Morgenstern, R.D. W.A. Pizer, and J. Shih. 2002. "Jobs versus the environment: an industry-level perspective," *Journal of Environmental Economics and Management* 43(3):412-436.

Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Oil and Gas Journal. "OGJ150." September 21, 2009.

Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.

U.S. Small Business Administration (U.S. SBA), Office of Advocacy. 2010. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272.

U.S. Energy Information Administration (U.S. EIA). 2010. Documentation of the Oil and Gas Supply Module (OGSM). May 2010. DOE/EIA-M06(2010). <http://www.eia.gov/FTPROOT/modeldoc/m063(2010).pdf> Accessed March 30, 2011.

U.S. Energy Information Administration (U.S. EIA). 2010. Model Documentation Natural Gas Transmission and Distribution Module of the National Energy Modeling System. June 2010. DOE/EIA-M062(2010) <http://www.eia.gov/FTPROOT/modeldoc/m062(2010).pdf> Accessed March 30, 2011.

ORIGINAL ARTICLE

Long-Term Ozone Exposure and Mortality

Michael Jerrett, Ph.D., Richard T. Burnett, Ph.D., C. Arden Pope III, Ph.D., Kazuhiko Ito, Ph.D., George Thurston, Sc.D., Daniel Krewski, Ph.D., Yuanli Shi, M.D., Eugenia Calle, Ph.D., and Michael Thun, M.D.

ABSTRACT

BACKGROUND

Although many studies have linked elevations in tropospheric ozone to adverse health outcomes, the effect of long-term exposure to ozone on air pollution–related mortality remains uncertain. We examined the potential contribution of exposure to ozone to the risk of death from cardiopulmonary causes and specifically to death from respiratory causes.

METHODS

Data from the study cohort of the American Cancer Society Cancer Prevention Study II were correlated with air-pollution data from 96 metropolitan statistical areas in the United States. Data were analyzed from 448,850 subjects, with 118,777 deaths in an 18-year follow-up period. Data on daily maximum ozone concentrations were obtained from April 1 to September 30 for the years 1977 through 2000. Data on concentrations of fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) were obtained for the years 1999 and 2000. Associations between ozone concentrations and the risk of death were evaluated with the use of standard and multilevel Cox regression models.

RESULTS

In single-pollutant models, increased concentrations of either $PM_{2.5}$ or ozone were significantly associated with an increased risk of death from cardiopulmonary causes. In two-pollutant models, $PM_{2.5}$ was associated with the risk of death from cardiovascular causes, whereas ozone was associated with the risk of death from respiratory causes. The estimated relative risk of death from respiratory causes that was associated with an increment in ozone concentration of 10 ppb was 1.040 (95% confidence interval, 1.010 to 1.067). The association of ozone with the risk of death from respiratory causes was insensitive to adjustment for confounders and to the type of statistical model used.

CONCLUSIONS

In this large study, we were not able to detect an effect of ozone on the risk of death from cardiovascular causes when the concentration of $PM_{2.5}$ was taken into account. We did, however, demonstrate a significant increase in the risk of death from respiratory causes in association with an increase in ozone concentration.

From the University of California, Berkeley (M.J.); Health Canada, Ottawa (R.T.B.); Brigham Young University, Provo, UT (C.A.P.); New York University School of Medicine, New York (K.I., G.T.); the University of Ottawa, Ottawa (D.K., Y.S.); and the American Cancer Society, Atlanta (E.C., M.T.). Address reprint requests to Dr. Jerrett at the Division of Environmental Health Sciences, School of Public Health, University of California, 710 University Hall, Berkeley, CA 94720, or at jerrett@berkeley.edu.

N Engl J Med 2009;360:1085-95.
Copyright © 2009 Massachusetts Medical Society.

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

Studies conducted over the past 15 years have provided substantial evidence that long-term exposure to air pollution is a risk factor for cardiopulmonary disease and death.[1-5] Recent reviews of this literature suggest that fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) has a primary role in these adverse health effects.[6,7] The particulate-matter component of air pollution includes complex mixtures of metals, black carbon, sulfates, nitrates, and other direct and indirect byproducts of incomplete combustion and high-temperature industrial processes.

Ozone is a single, well-defined pollutant, yet the effect of exposure to ozone on air pollution–related mortality remains inconclusive. Several studies have evaluated this issue, but they have been short-term studies,[8-10] have failed to show a statistically significant effect,[1,3] or have been based on limited mortality data.[11] Recent reviews by the Environmental Protection Agency (EPA)[12] and the National Research Council[13] have questioned the overall consistency of the available data correlating exposure to ozone and mortality. Similar conclusions about the evidence base for the long-term effects of ozone on mortality were drawn by a panel of experts in the United Kingdom.[14]

Nonetheless, previous studies have suggested that a measurable effect of ozone may exist, particularly with respect to the risk of death from cardiopulmonary causes. In one of the larger studies, ozone was significantly associated with death from cardiopulmonary causes[15] but not with death from ischemic heart disease. However, the estimated effect of ozone on the risk of death from cardiopulmonary causes in this study was attenuated when $PM_{2.5}$ was added to the analysis in copollutant models. On the basis of suggested effects of ozone on the risk of death from cardiopulmonary causes (which includes death from respiratory causes) but an absence of evidence for effects of ozone on the risk of death from ischemic heart disease, we hypothesized that ozone might have a primary effect on the risk of death from respiratory causes.

METHODS

HEALTH, MORTALITY, AND CONFOUNDING DATA

Our study used data from the American Cancer Society Cancer Prevention Study II (CPS II) cohort.[16] The CPS II cohort consists of more than 1.2 million participants who were enrolled by American Cancer Society volunteers between September 1982 and February 1983 in all 50 states, the District of Columbia, and Puerto Rico. Enrollment was restricted to persons who were at least 30 years of age living in households with at least one person 45 years of age or older. After providing written informed consent, the participants completed a confidential questionnaire that included questions on demographic characteristics, smoking history, alcohol use, diet, and education.[17] Deaths were ascertained until August 1988 by personal inquiries of family members by the volunteers and thereafter by linkage with the National Death Index. Through 1995, death certificates were obtained and coded for cause of death. Beginning in 1996, codes for cause of death were provided by the National Death Index.[18]

The study population for our analysis included only those participants in CPS II who resided in U.S. metropolitan statistical areas within the 48 contiguous states or the District of Columbia (according to their address at the time of enrollment) and for whom data were available from at least one pollution monitor within their metropolitan area. The study was approved by the Ottawa Hospital Research Ethics Board, Canada.

Data on "ecologic" risk factors at the level of the metropolitan area representing social variables (educational level, percentage of homes with air conditioning, percentage of the population who were nonwhite), economic variables (household income, unemployment, income disparity), access to medical care (number of physicians and hospital beds per capita), and meteorologic variables were obtained from the 1980 U.S. Census and other secondary sources (see the Supplementary Appendix, available with the full text of this article at NEJM.org). These ecologic risk factors, as well as the individual risk factors collected in the CPS II questionnaire, were assessed as potential confounders of the effects of ozone.[3,5,19,20]

ESTIMATES OF EXPOSURE TO AIR POLLUTION

Ozone data were obtained from 1977 (5 years before the identification of the CPS II cohort) through 2000 for all air-pollution monitors in the study metropolitan areas from the EPA's Aerometric Information Retrieval System. Ozone data at each monitoring site were collected on an hourly basis, and the daily maximum value for the site was determined. All available daily maximum values for the monitoring site were averaged over

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

each quarter year. The quarterly average values were reported for each monitor only when at least 75% of daily observations for that quarter were available.

The averages of the second (April through June) and third (July through September) quarters were calculated for each monitor if both quarterly averages were available. The period from April through September was selected because ozone concentrations tend to be elevated during the warmer seasons and because fewer data were available for the cooler seasons.

The average of the second and third quarterly averages for each year was then computed for all the monitors within each metropolitan area to form a single annual time series of air-pollution measurements for each metropolitan area for the period from 1977 to 2000. In addition, a summary measure of long-term exposure to ambient warm-season ozone was defined as the average of annual time-series measurements during the entire period from 1977 to 2000. Individual measures of exposure to ozone were then defined by assigning the average for the metropolitan area to each cohort member residing in that area.

Data on exposure to $PM_{2.5}$ were also obtained from the Aerometric Information Retrieval System database for the 2-year period from 1999 to 2000 (data on $PM_{2.5}$ were not available before 1999 for most metropolitan areas).[5] The average concentrations of $PM_{2.5}$ were included in our analyses to distinguish the effect of particulates from that of ozone on outcomes.

STATISTICAL ANALYSIS

Standard and multilevel random-effects Cox proportional-hazard models were used to assess the risk of death in relation to exposures to pollution. The subjects were matched according to age (in years), sex, and race. A total of 20 variables with 44 terms were used to control for individual characteristics that might confound or modify the association between air pollution and death. These variables, which were considered to be of potential importance on the basis of previous studies, included individual risk factors for which data had been collected in the CPS II questionnaire. Seven ecologic covariates obtained from the 1980 U.S. Census (median household income, the proportion of persons living in households with an income below 125% of the poverty line, the percentage of persons over the age of 16 years who were unemployed, the percentage of adults with less than a high-school [12th-grade] education, the percentage of homes with air conditioning, the Gini coefficient of income inequality [ranging from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income[20]], and the percentage of persons who were white) were also included. These variables were included at two levels: as the average for the metropolitan statistical area and as the difference between the average for the ZIP Code of residence and the average for the metropolitan statistical area. Additional sensitivity analyses were undertaken for ecologic variables that were available for only a subgroup of the 96 metropolitan statistical areas (see the Supplementary Appendix). Models were estimated for either ozone or $PM_{2.5}$. In addition, models with both $PM_{2.5}$ and ozone were estimated.

In additional analyses, our basic Cox models were modified by incorporating an adjustment for community-level random effects, which allowed us to take into account residual variation in mortality among communities.[21] The baseline hazard function was modulated by a community-specific random variable representing the residual risk of death for subjects in that community after individual and ecologic risk factors had been controlled for (see the Supplementary Appendix).

A formal analysis was conducted to assess whether a threshold existed for the association between exposure to ozone and the risk of death (see the Supplementary Appendix). A standard threshold model was postulated in which there was no association between exposure to ozone and the risk of death below a specified threshold concentration and a linear association (on the logarithmic scale of the proportional-hazards model) above the threshold.

The question of whether specific time windows were associated with the health effects was investigated by subdividing the follow-up interval into four periods (1982 to 1988, 1989 to 1992, 1993 to 1996, and 1997 to 2000). Exposures were matched for each of these periods and also tested for a 10-year average on the basis of the 5-year follow-up period and the 5 years before the follow-up period (see the Supplementary Appendix).

RESULTS

The analytic cohort included 448,850 subjects residing in 96 metropolitan statistical areas (Fig. 1).

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

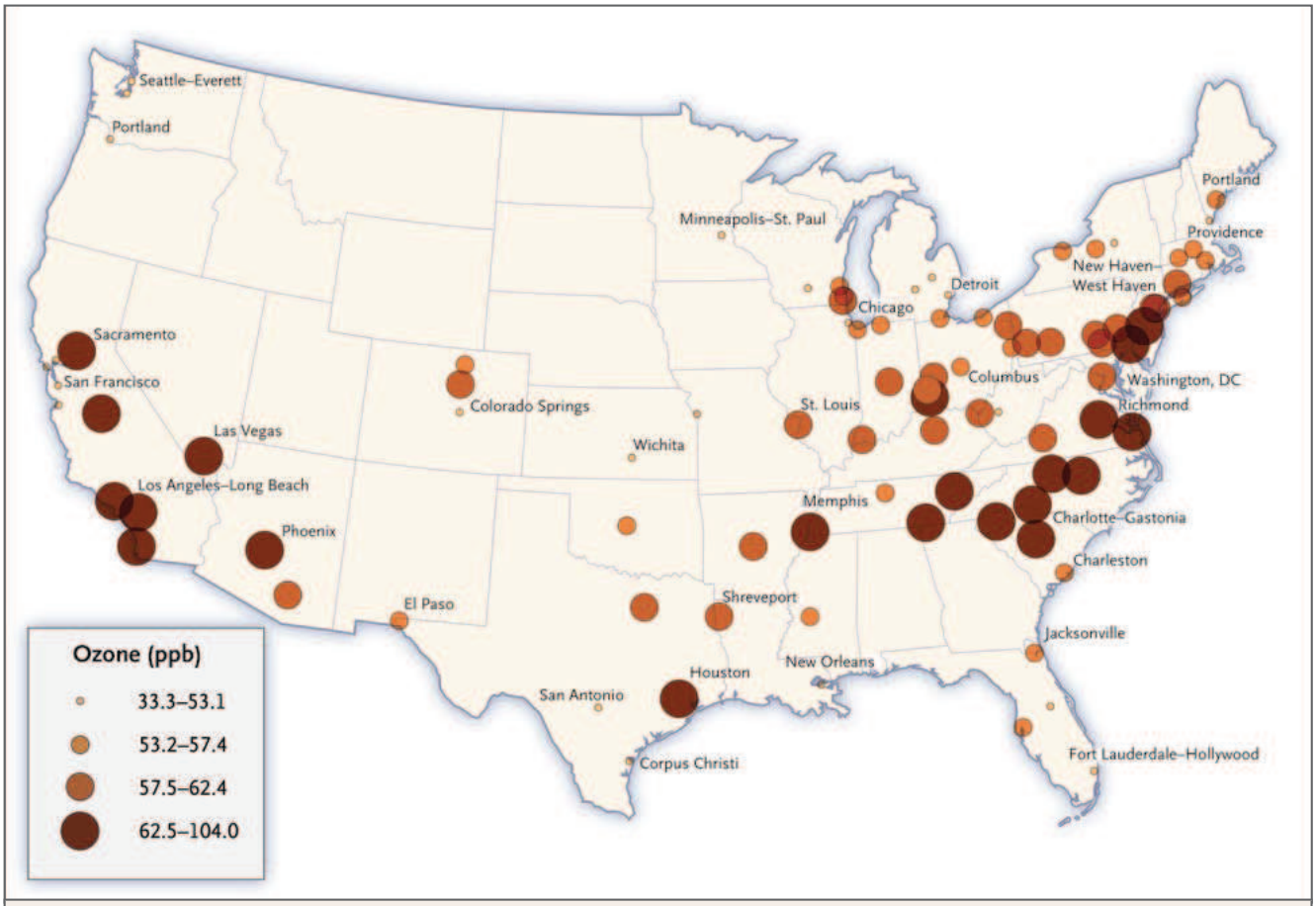


Figure 1. Ozone Concentrations in the 96 Metropolitan Statistical Areas in Which Members of the American Cancer Society Cohort Resided in 1982.

The average exposures were estimated from 1 to 57 monitoring sites within each metropolitan area from April 1 to September 30 for the years 1977 through 2000.

In 1980, the populations of these 96 areas ranged from 94,436 to 8,295,900. Data were available on the concentration of ambient ozone from all 96 areas and on the concentration of $PM_{2.5}$ from 86 areas. The average number of air-pollution monitors per metropolitan area was 11 (range, 1 to 57), and more than 80% of the areas had 6 or more monitors.

The average ozone concentration for each metropolitan area during the interval from 1977 to 2000 ranged from 33.3 ppb to 104.0 ppb (Fig. 1). The highest regional concentrations were in Southern California and the lowest in the Pacific Northwest and parts of the Great Plains. Moderately elevated concentrations were present in many areas of the East, Midwest, South, and Southwest.

The baseline characteristics of the study population, overall and as a function of exposure to ozone, are presented in Table 1. The mean age of the cohort was 56.6 years, 43.4% were men, 93.7% were white, 22.4% were current smokers, and 30.5% were former smokers. On the basis of estimates from 1980 Census data, 62.3% of homes had air conditioning at the time of initial data collection.

During the 18-year follow-up period (from initial CPS II data collection in 1982 through the end of follow-up in 2000), there were 118,777 deaths in the study cohort (Table 2). Of these, 58,775 were from cardiopulmonary causes, including 48,884 from cardiovascular causes (of which 27,642 were due to ischemic heart disease) and 9891 from respiratory causes.

In the single-pollutant models, exposure to ozone was not associated with the overall risk of death (relative risk, 1.001; 95% confidence interval [CI], 0.996 to 1.007) (Table 3). However, it was significantly correlated with an increase in the risk of death from cardiopulmonary causes. A

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

10-ppb increment in exposure to ozone elevated the relative risk of death from the following causes: cardiopulmonary causes (relative risk, 1.014; 95% CI, 1.007 to 1.022), cardiovascular causes (relative risk, 1.011; 95% CI, 1.003 to 1.023), ischemic heart disease (relative risk, 1.015; 95% CI, 1.003 to 1.026), and respiratory causes (relative risk, 1.029; 95% CI, 1.010 to 1.048).

Inclusion of the concentration of $PM_{2.5}$ measured in 1999 and 2000 as a copollutant (Table 3) attenuated the association with exposure to ozone for all the end points except death from respiratory causes, for which a significant correlation persisted (relative risk, 1.040; 95% CI, 1.013 to 1.067). The concentrations of ozone and $PM_{2.5}$ were positively correlated (r=0.64 at the subject level and r=0.56 at the metropolitan-area level), resulting in unstable risk estimates for both pollutants. The concentration of $PM_{2.5}$ remained significantly associated with death from cardio-

Table 1. Baseline Characteristics of the Study Population in the Entire Cohort and According to Exposure to Ozone.*

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
No. of MSAs	96	24	24	24	24
No. of MSAs with data on $PM_{2.5}$	86	21	20	23	22
Concentration of $PM_{2.5}$ ($\mu g/m^3$)		11.9±2.5	13.1±2.9	14.7±2.1	15.4±3.2
Individual risk factors					
Age (yr)	56.6±10.5	56.7±10.4	56.4±10.7	56.3±10.4	56.9±10.5
Male sex (%)	43.4	43.5	43.1	43.5	43.2
White race (%)	93.7	94.3	95.1	93.9	91.8
Education (%)					
Less than high school	12.1	11.5	13.6	12.1	11.6
High school	30.6	30.2	33.6	32.1	27.4
Beyond high school	57.3	58.3	52.8	55.8	61.0
Smoking status					
Current smokers					
Percentage of subjects	22.4	22.0	23.5	22.2	21.9
No. of cigarettes/day	22.0±12.4	22.0±12.3	22.0±12.5	22.2±12.5	21.9±12.4
Duration of smoking (yr)	33.5±11.0	33.4±10.8	33.4±11.1	33.4±11.0	33.9±11.2
Started smoking <18 yr of age (%)	9.6	9.3	10.5	9.4	9.3
Started smoking ≥18 yr of age (%)	13.2	13.3	13.4	13.3	13.0
Former smokers					
Percentage of subjects	30.5	31.2	30.8	29.5	30.4
No. of cigarettes/day	21.6±14.7	21.6±14.6	22.2±15.1	21.6±14.6	21.3±14.6
Duration of smoking (yr)	22.2±12.6	22.1±12.5	22.6±12.6	22.0±12.5	22.4±12.7
Started smoking <18 yr of age (%)	11.9	11.8	12.7	11.5	11.8
Started smoking ≥18 yr of age (%)	18.5	19.3	17.9	17.9	18.5
Exposure to smoking (hr/day)	3.3±4.4	3.2±4.4	3.4±4.5	3.4±4.5	3.1±4.4
Pipe or cigar smoker only (%)	4.1	4.0	4.2	4.3	3.8
Marital status (%)					
Married	83.5	84.2	83.0	83.7	83.1
Single	3.6	3.4	4.0	3.8	3.2
Separated, divorced, or widowed	12.9	12.4	13.0	12.5	13.7

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Body-mass index†	25.1±4.1	25.1±4.1	25.3±4.2	25.1±4.1	24.8±4.0
Level of occupational exposure to particulate matter (%)‡					
0	50.7	50.9	50.0	50.8	51.0
1	13.3	13.4	13.1	13.3	13.3
2	11.4	11.5	10.8	11.4	11.9
3	4.6	4.7	4.8	4.6	4.5
4	6.1	6.2	6.2	6.1	6.0
5	4.2	4.2	4.3	4.1	4.1
6	1.1	1.0	9.5	1.4	8.4
Not able to ascertain	8.6	8.2	1.2	8.4	0.9
Self-reported exposure to dust or fumes (%)	19.5	19.5	19.8	19.7	19.1
Level of dietary-fat consumption (%)§					
0	14.5	13.7	14.9	14.1	15.3
1	15.9	15.8	16.5	15.6	15.9
2	17.4	17.6	17.7	17.2	17.1
3	21.2	21.8	21.1	21.3	20.8
4	30.9	31.1	29.8	31.9	30.9
Level of dietary-fiber consumption (%)¶					
0	16.6	16.0	17.5	16.7	16.6
1	19.9	19.4	20.5	20.1	19.7
2	18.8	18.6	19.2	19.1	18.5
3	22.8	23.0	22.4	22.8	22.7
4	21.9	23.0	20.4	21.3	22.5
Alcohol consumption (%)					
Beer					
Drinks beer	22.9	24.3	23.2	22.9	21.4
Does not drink beer	9.7	9.5	9.3	9.5	10.2
No data	67.4	66.2	67.5	67.6	68.4
Liquor					
Drinks liquor	28.0	30.4	27.9	25.4	27.9
Does not drink liquor	8.8	8.4	8.5	10.1	9.2
No data	63.2	61.2	63.6	65.5	62.9
Wine					
Drinks wine	23.5	25.4	22.5	21.1	24.3
Does not drink wine	8.9	8.7	8.8	9.3	9.1
No data	67.6	65.9	68.7	69.6	66.6

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Ecologic risk factors‖					
Nonwhite race (%)	11.6±16.8	10.5±16.4	9.3±15.5	10.2±16.0	15.9±18.3
Home with air conditioning (%)	62.3±27.0	55.4±31.2	59.4±24.0	65.3±24.8	69.1±24.3
High-school education or greater (%)	51.7±8.2	53.5±7.9	52.4±7.5	50.8±7.2	50.0±9.5
Unemployment rate (%)	11.7±3.1	12.1±3.4	11.3±2.6	11.3±2.9	11.8±3.4
Gini coefficient of income inequality**	0.37±0.04	0.37±0.05	0.37±0.04	0.37±0.04	0.38±0.04
Proportion of population with income <125% of poverty line	0.12±0.08	0.11±0.08	0.12±0.08	0.11±0.07	0.13±0.09
Annual household income (thousands of dollars)††	20.7±6.6	21.9±7.1	19.8±6.0	21.2±6.7	19.7±6.3

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Plus–minus values are means ±SD. Because of rounding, percentages may not total 100. All baseline characteristics included in the survival model are listed (age, sex, and race were included as stratification factors). The model also includes squared terms for the number of cigarettes smoked per day and the number of years of smoking for both current and former smokers and a squared term for body-mass index.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Occupational exposure to particulate matter increases with increasing index number. The index was calculated by assigning a relative level of exposure to $PM_{2.5}$ associated with a cohort member's job and industry. These assignments were performed by industrial hygienists on the basis of their knowledge of typical exposure patterns for each occupation and specific job.[22]

§ Dietary-fat consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fat consumption according to five ordered categories.[20]

¶ Dietary-fiber consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fiber consumption according to five ordered categories.[23]

‖ For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. Some values for ecologic variables and individual variables differ, although they appear to measure the same risk factor. For example, for the entire cohort, the percentage of whites as listed under individual variables is 93.7, whereas the percentage of nonwhites as listed under ecologic variables is 11.6±16.8. This apparent contradiction is explained by the fact that the former is an exact figure based on the individual reports of the study participants in the CPS II questionnaire, whereas the latter is a mean (±SD) for the population based on Census estimates for each metropolitan statistical area.

** The Gini coefficient is a statistical dispersion measure used to calculate income inequality. The coefficient ranges from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income.[20] A coefficient of 0.37 indicates that on average there is a measurable inequality in the distribution of income among the different income groups within the MSAs.

†† Average household incomes for the cohort and for each quartile of ozone concentration were calculated from the median household income for the metropolitan statistical area.

pulmonary causes, cardiovascular causes, and ischemic heart disease when ozone was included in the model. The association of ozone concentrations with death from respiratory causes remained significant after adjustment for $PM_{2.5}$.

Risk estimates for ozone-related death from respiratory causes were insensitive to the use of a random-effects survival model allowing for spatial clustering within the metropolitan area and state of residence (Table 1S in the Supplementary Appendix). The association between increased ozone concentrations and increased risk of death from respiratory causes was also insensitive to adjustment for several ecologic variables considered individually (Table 2S in the Supplementary Appendix).

Subgroup analyses showed that environmental temperature and region of the country, but not sex, age at enrollment, body-mass index, education, or concentration of $PM_{2.5}$, significantly modified the effects of ozone on the risk of death from respiratory causes (Table 4).

Figure 2 illustrates the shape of the relation between exposure to ozone and death from re-

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

Table 2. Number of Deaths in the Entire Cohort and According to Exposure to Ozone.

Cause of Death	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
		number of deaths			
Any cause	118,777	32,957	25,642	27,782	32,396
Cardiopulmonary	58,775	16,328	12,621	13,544	16,282
Cardiovascular	48,884	13,605	10,657	11,280	13,342
Ischemic heart disease	27,642	7,714	6,384	6,276	7,268
Respiratory	9,891	2,723	1,964	2,264	2,940

Table 3. Relative Risk of Death Attributable to a 10-ppb Change in the Ambient Ozone Concentration.*

Cause of Death	Single-Pollutant Model†			Two-Pollutant Model‡	
	Ozone (96 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)
			relative risk (95% CI)		
Any cause	1.001 (0.996–1.007)	1.001 (0.996–1.007)	1.048 (1.024–1.071)	0.989 (0.981–0.996)	1.080 (1.048–1.113)
Cardiopulmonary	1.014 (1.007–1.022)	1.016 (1.008–1.024)	1.129 (1.094–1.071)	0.992 (0.982–1.003)	1.153 (1.104–1.204)
Respiratory	1.029 (1.010–1.048)	1.027 (1.007–1.046)	1.031 (0.955–1.113)	1.040 (1.013–1.067)	0.927 (0.836–1.029)
Cardiovascular	1.011 (1.003–1.023)	1.014 (1.005–1.023)	1.150 (1.111–1.191)	0.983 (0.971–0.994)	1.206 (1.150–1.264)
Ischemic heart disease	1.015 (1.003–1.026)	1.017 (1.006–1.029)	1.211 (1.156–1.268)	0.973 (0.958–0.988)	1.306 (1.226–1.390)

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone concentrations were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000; changes in the concentration of $PM_{2.5}$ of 10 μg per cubic meter were recorded for members of the cohort in 1999 and 2000. These models are adjusted for all the individual and ecologic risk factors listed in Table 1. For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. The risk of death was stratified according to age (in years), sex, and race.

† The single-pollutant models were based on 96 metropolitan statistical areas for which information on ozone was available and 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

‡ The two-pollutant models were based on 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

spiratory causes. There was limited evidence that a threshold model specification improved model fit as compared with a nonthreshold linear model (P=0.06) (Table 3S in the Supplementary Appendix).

Because air-pollution data from 1977 to 2000 were averaged, exposure values for persons who died during this period are based partly on data that were obtained after death had occurred. Further investigation by dividing this interval into specific time windows of exposure revealed no significant difference between the effects of earlier and later time windows within the period of follow-up. Allowing for a 10-year period of exposure to ozone (5 years of follow-up and 5 years before the follow-up period) did not appreciably alter the risk estimates (Table 4S in the Supplementary Appendix). Thus, when exposure values were matched more closely to the follow-up period and when exposure values were based on data obtained before the deaths, there was little change in the results.

DISCUSSION

Our principal finding is that ozone and $PM_{2.5}$ contributed independently to increased annual mortality rates in this large, U.S. cohort study in analyses that controlled for many individual and ecologic risk factors. In two-pollutant models that

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

included ozone and $PM_{2.5}$, ozone was significantly associated only with death from respiratory causes.

For every 10-ppb increase in exposure to ozone, we observed an increase in the risk of death from respiratory causes of about 2.9% in single-pollutant models and 4% in two-pollutant models. Although this increase may appear moderate, the risk of dying from a respiratory cause is more than three times as great in the metropolitan areas with the highest ozone concentrations as in those with the lowest ozone concentrations. The effects of ozone on the risk of death from respiratory causes were insensitive to adjustment for individual, neighborhood, and metropolitan-area confounders or to differences in multilevel-model specifications.

There is biologic plausibility for a respiratory effect of ozone. In laboratory studies, ozone can increase airway inflammation[24] and can worsen pulmonary function and gas exchange.[25] In addition, exposure to elevated concentrations of tropospheric ozone has been associated with numerous adverse health effects, including the induction[26] and exacerbation[27,28] of asthma, pulmonary dysfunction,[29,30] and hospitalization for respiratory causes.[31]

Despite these observations, previous studies linking long-term exposure to ozone with death have been inconclusive. One cohort study conducted in the Midwest and eastern United States reported an inverse but nonsignificant association between ozone concentrations and mortality.[1] Subsequent reanalyses of this study replicated these findings but also suggested a positive association with exposure to ozone during warm seasons.[3] A study of approximately 6000 nonsmoking Seventh-Day Adventists living in Southern California showed elevated risks among men after long-term exposure to ozone,[11] but this finding was based on limited mortality data.

Previous studies using the CPS II cohort have also produced mixed results for ozone. An earlier examination based on a large sample of more than 500,000 people from 117 metropolitan areas and 8 years of follow-up indicated nonsignificant results for the relation between ozone and death from any cause and a significant inverse association between ozone and death from lung cancer. A positive association between death from cardiopulmonary causes and summertime exposure to ozone was observed in single-pollutant

Table 4. Relative Risk of Death from Respiratory Causes Attributable to a 10-ppb Change in the Ambient Ozone Concentration, Stratified According to Selected Risk Factors.*

Stratification Variable	% of Subjects in Stratum	Relative Risk (95% CI)	P Value of Effect Modification
Sex			0.11
Male	43	1.01 (0.99–1.04)	
Female	57	1.04 (1.03–1.07)	
Age at enrollment (yr)			0.74
<50	26	1.00 (0.90–1.11)	
50–65	54	1.03 (1.01–1.06)	
>65	20	1.02 (1.00–1.05)	
Education			0.48
High school or less	43	1.02 (1.00–1.05)	
Beyond high school	57	1.03 (1.01–1.06)	
Body-mass index†			0.96
<25.0	53	1.03 (1.01–1.06)	
25.0–29.9	36	1.03 (0.99–1.06)	
≥30.0	11	1.03 (0.96–1.10)	
$PM_{2.5}$ ($\mu g/m^3$)‡			0.38
<14.3	44	1.05 (1.01–1.09)	
>14.3	56	1.03 (1.00–1.05)	
Region§			0.05
Northeast	24.8	0.99 (0.92–1.07)	
Industrial Midwest	29.7	1.00 (0.91–1.09)	
Southeast	21.0	1.12 (1.05–1.19)	
Upper Midwest	5.2	1.14 (0.68–1.90)	
Northwest	7.7	1.06 (1.00–1.13)	
Southwest	3.9	1.21 (1.04–1.40)	
Southern California	7.8	1.01 (0.96–1.07)	
External temperature (°C)‡¶			0.01
<23.3	24	0.96 (0.90–1.01)	
>23.3 to <25.4	29	0.97 (0.87–1.08)	
>25.4 to <28.7	22	1.04 (0.92–1.16)	
>28.7	25	1.05 (1.03–1.08)	

* $PM_{2.5}$ denotes fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone exposures for the cohort were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000, with adjustment for individual risk factors, and with baseline hazard function stratified according to age (single-year groupings), sex, and race. These analyses are based on the single-pollutant model for ozone shown in Table 3. Because of rounding, percentages may not total 100.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Stratum cutoff is based on the median of the distribution at the metropolitan-area level, not at the subject level.

§ Definitions of regions are those used by the Environmental Protection Agency.[3]

¶ External temperature is calculated as the average daily maximum temperature recorded between April and September from 1977 to 2000.

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

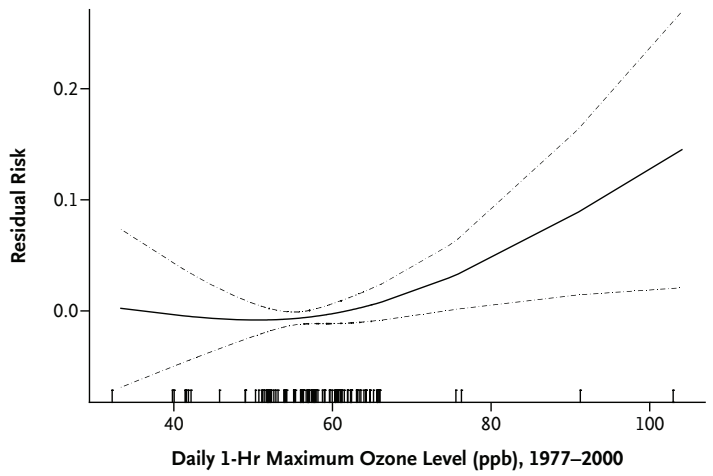


Figure 2. Exposure–Response Curve for the Relation between Exposure to Ozone and the Risk of Death from Respiratory Causes.

The curve is based on a natural spline with 2 df estimated from the residual relative risk of death within a metropolitan statistical area (MSA) according to a random-effects survival model. The dashed lines indicate the 95% confidence interval of fit, and the hash marks indicate the ozone levels of each of the 96 MSAs.

models, but the association with ozone was nonsignificant in two-pollutant models.[3] Further analyses based on 16 years of follow-up in 134 cities produced similarly elevated but nonsignificant associations that were suggestive of effects of summertime (July to September) exposure to ozone on death from cardiopulmonary causes.[5]

The increase in deaths from respiratory causes with increasing exposure to ozone may represent a combination of short-term effects of ozone on susceptible subjects who have influenza or pneumonia and long-term effects on the respiratory system caused by airway inflammation,[24] with subsequent loss of lung function in childhood,[32] young adulthood,[33,34] and possibly later life.[35] If exposure to ozone accelerates the natural loss of adult lung function with age, those exposed to higher concentrations of ozone would be at greater risk of dying from a respiratory-related syndrome.

In our two-pollutant models, the adjusted estimates of relative risk for the effect of ozone on the risk of death from cardiovascular causes were significantly less than 1.0, seemingly suggesting a protective effect. Such a beneficial influence of ozone, however, is unlikely from a biologic standpoint. The association of ozone with cardiovascular end points was sensitive to adjustment for exposure to $PM_{2.5}$, making it difficult to determine precisely the independent contributions of these copollutants to the risk of death. There was notable collinearity between the concentrations of ozone and $PM_{2.5}$.

Furthermore, measurement at central monitors probably represents population exposure to $PM_{2.5}$ more accurately than it represents exposure to ozone. Ozone concentration tends to vary spatially within cities more than does $PM_{2.5}$ concentration, because of scavenging of ozone by nitrogen oxide near roadways.[36] In the presence of a high density of local traffic, the measurement error is probably higher for exposure to ozone than for exposure to $PM_{2.5}$. The effects of ozone could therefore be confounded by the presence of $PM_{2.5}$ because of collinearity between the measurements of the two pollutants and the higher precision of measurements of $PM_{2.5}$.[37]

Measurements of $PM_{2.5}$ were available only for the end of the study follow-up period (1999 and 2000). Widespread collection of these data began only after the EPA adopted regulatory limits on such particulates in 1997. Since particulate air pollution has probably decreased in most metropolitan areas during the follow-up interval of our study, it is likely that we have underestimated the effect of $PM_{2.5}$ in our analysis.

A limitation of our study is that we were not able to account for the geographic mobility of the population during the follow-up period. We had information on home addresses for the CPS II cohort only at the time of initial enrollment in 1982 and 1983. Census data indicate that during the interval between 1982 and 2000, approximately 2 to 3% of the population moved from one state to another annually (with the highest rates in an age group younger than that of our study population).[38] However, any bias due to a failure to account for geographic mobility is likely to have attenuated, rather than exaggerated, the effects of ozone on mortality.

In summary, we investigated the effect of tropospheric ozone on the risk of death from any cause and cause-specific death in a large cohort, using data from 96 metropolitan statistical areas across the United States and controlling for the effect of particulate air pollutants. We were unable to detect a significant effect of exposure to ozone on the risk of death from cardiovascular causes when particulates were taken into account, but we did demonstrate a significant effect of exposure to ozone on the risk of death from respiratory causes.

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.

Supported by the Health Effects Institute.

Dr. Krewski reports receiving grant support from the Natural Sciences and Engineering Research Council of Canada as holder of the Industrial Research Chair in Risk Science. This chair is funded by a peer-reviewed university–industry partnership program. No other potential conflict of interest relevant to this article was reported.

We thank the National Institute of Environmental Health Sciences for providing grant support (ES00260) to the New York University School of Medicine.

This article is dedicated to the memory of our coauthor and friend, Dr. Jeanne Calle, who died unexpectedly on February 17, 2009.

REFERENCES

1. Dockery DW, Pope AC, Xu X, et al. An association between air pollution and mortality in six U.S. cities. N Engl J Med 1993;329:1753-9.

2. Jerrett M, Burnett RT, Ma RJ, et al. Spatial analysis of air pollution and mortality in Los Angeles. Epidemiology 2005; 16:727-36.

3. Krewski D, Burnett RT, Goldberg MS, et al. Reanalysis of the Harvard Six Cities Study and the American Cancer Society Study of Particulate Air Pollution and Mortality: a special report of the institute's Particle Epidemiology Reanalysis Project. Part II. Sensitivity analyses. Cambridge, MA: Health Effects Institute, 2000.

4. Miller KA, Siscovick DS, Sheppard L, et al. Long-term exposure to air pollution and incidence of cardiovascular events in women. N Engl J Med 2007;356:447-58.

5. Pope CA III, Burnett RT, Thun MJ, et al. Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. JAMA 2002;287:1132-41.

6. Brook RD, Franklin B, Cascio W, et al. Air pollution and cardiovascular disease: a statement for healthcare professionals from the Expert Panel on Population and Prevention Science of the American Heart Association. Circulation 2004;109:2655-71.

7. Pope CA III, Dockery DW. Health effects of fine particulate air pollution: lines that connect. J Air Waste Manag Assoc 2006;56:709-42.

8. Bell ML, Dominici F, Samet JM. A meta-analysis of time-series studies of ozone and mortality with comparison to the National Morbidity, Mortality, and Air Pollution Study. Epidemiology 2005;16:436-45.

9. Ito K, De Leon SF, Lippmann M. Associations between ozone and daily mortality: analysis and meta-analysis. Epidemiology 2005;16:446-57.

10. Levy JI, Chemerynski SM, Sarnat JA. Ozone exposure and mortality: an empiric Bayes metaregression analysis. Epidemiology 2005;16:458-68.

11. Abbey DE, Nishino N, McDonnell WF, et al. Long-term inhalable particles and other air pollutants related to mortality in nonsmokers. Am J Respir Crit Care Med 1999;159:373-82.

12. Review of the national ambient air quality standards for ozone: policy assessment of scientific and technical information. Research Triangle Park, NC: Environmental Protection Agency, 2007. (Report no. EPA-452/R-07-007.)

13. Committee on Estimating Mortality Risk Reduction Benefits from Decreasing Tropospheric Ozone Exposure. Estimating mortality risk reduction and economic benefits from controlling ozone air pollution. Washington, DC: National Academies Press, 2008.

14. The Committee on the Medical Effects of Air Pollutants. The effects on health of long-term exposure to ozone. London: Department of Health, 2007. (Accessed February 17, 2009, at http://www.advisorybodies.doh.gov.uk/comeap/statementsreports/chptlongtermexpoozone.pdf.)

15. Krewski D, Jerrett M, Burnett RT, et al. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. Boston: Health Effects Institute (in press).

16. American Cancer Society. Cancer prevention study overviews. (Accessed February 17, 2009, at http://www.cancer.org/docroot/RES/content/RES_6_2_Study_Overviews.asp?)

17. Thun MJ, Calle EE, Namboodiri MM, et al. Risk factors for fatal colon cancer in a large prospective study. J Natl Cancer Inst 1992;84:1491-500.

18. Calle EE, Terrell DD. Utility of the National Death Index for ascertainment of mortality among Cancer Prevention Study II participants. Am J Epidemiol 1993;137: 235-41.

19. Jerrett M, Burnett RT, Willis A, et al. Spatial analysis of the air pollution-mortality relationship in the context of ecologic confounders. J Toxicol Environ Health A 2003;66:1735-77.

20. Willis A, Krewski D, Jerrett M, Goldberg MS, Burnett RT. Selection of ecologic covariates in the American Cancer Society study. J Toxicol Environ Health A 2003; 66:1563-89.

21. Ma R, Krewski D, Burnett RT. Random effects Cox models: a Poisson modelling approach. Biometrika 2003;90:157-69.

22. Siemiatycki J, Krewski D, Shi Y, Goldberg MS, Nadon L, Lakhani R. Controlling for potential confounding by occupational exposures. J Toxicol Environ Health A 2003;66:1591-603.

23. Chao A, Thun MJ, Jacobs EJ, Henley SJ, Rodriguez C, Calle EE. Cigarette smoking and colorectal cancer mortality in the Cancer Prevention Study II. J Natl Cancer Inst 2000;92:1888-96.

24. Mudway IS, Kelly FJ. An investigation of inhaled ozone dose and the magnitude of airway inflammation in healthy adults. Am J Respir Crit Care Med 2004;169:1089-95.

25. Brown JS, Bateson TF, McDonnell WF. Effects of exposure to 0.06 ppm ozone on FEV1 in humans: a secondary analysis of existing data. Environ Health Perspect 2008;116:1023-6.

26. McConnell R, Berhane K, Gilliland F, et al. Asthma in exercising children exposed to ozone: a cohort study. Lancet 2002;359:386-91. [Erratum, Lancet 2002; 359:896.]

27. Delfino RJ, Quintana PJ, Floro J, et al. Association of FEV1 in asthmatic children with personal and microenvironmental exposure to airborne particulate matter. Environ Health Perspect 2004;112:932-41.

28. Thurston GD, Lippmann M, Scott MB, Fine JM. Summertime haze air pollution and children with asthma. Am J Respir Crit Care Med 1997;155:654-60.

29. Spektor DM, Lippmann M, Lioy PJ, et al. Effects of ambient ozone on respiratory function in active, normal children. Am Rev Respir Dis 1988;137:313-20.

30. Tager IB, Balmes J, Lurmann F, Ngo L, Alcorn S, Künzli N. Chronic exposure to ambient ozone and lung function in young adults. Epidemiology 2005;16:751-9.

31. Yang Q, Chen Y, Shi Y, Burnett RT, McGrail KM, Krewski D. Association between ozone and respiratory admissions among children and the elderly in Vancouver, Canada. Inhal Toxicol 2003;15: 1297-308.

32. Rojas-Martinez R, Perez-Padilla R, Olaiz-Fernandez G, et al. Lung function growth in children with long-term exposure to air pollutants in Mexico City. Am J Respir Crit Care Med 2007;176:377-84.

33. Galizia A, Kinney PL. Long-term residence in areas of high ozone: associations with respiratory health in a nationwide sample of nonsmoking young adults. Environ Health Perspect 1999;107:675-9.

34. Chen C, Arjomandi M, Balmes J, Tager IB, Holland N. Effects of chronic and acute ozone exposure on lipid peroxidation and antioxidant capacity in healthy young adults. Environ Health Perspect 2007;115:1732-7.

35. Ackermann-Liebrich U, Leuenberger P, Schwartz J, et al. Lung function and long term exposure to air pollutants in Switzerland. Am J Respir Crit Care Med 1997;155:122-9.

36. McConnell R, Berhane K, Yao L, Lurmann FW, Avol E, Peters JM. Predicting residential ozone deficits from nearby traffic. Sci Total Environ 2006;363:166-74.

37. Zidek JV, Wong H, Le ND, Burnett R. Causality: measurement error and multicollinearity in epidemiology. Environmetrics 1996;7:441-51.

38. Schachter J. Geographical mobility: population characteristics. March 1999 to March 2000. Current population reports PPL-144. Washington, DC: Census Bureau, May 2001. (Accessed February 17, 2009, at http://www.census.gov/prod/2001pubs/p20-538.pdf.)

Copyright © 2009 Massachusetts Medical Society.

The New England Journal of Medicine
Downloaded from nejm.org on November 6, 2012. For personal use only. No other uses without permission.
Copyright © 2009 Massachusetts Medical Society. All rights reserved.