Public Comments on the Jordan Cove Energy Project Proposed Air Quality Permit No. 06-0118-ST-01

Submitted to the Oregon Department of Environmental Quality on Behalf of:

Beyond Toxics
Cape Arago Audubon Society
Cascadia Wildlands
Citizens Against LNG
Clam Diggers Association of Oregon
Friends of Living Oregon Waters
Neighbors for Clean Air
Northwest Environmental Advocates
Northwest Environmental Defense Center
Oregon Coast Alliance
Oregon Shores Conservation Coalition
Oregon Wild
Rogue Climate
Rogue Riverkeeper
Sierra Club
South Umpqua Rural Community Partnership
Umpqua Watersheds, Inc.
Waterkeeper Alliance
Western Environmental Law Center

April 3, 2015

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Submitted electronically to Hamman.Patricia@deq.state.or.us

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Re: Public Comment Regarding Proposed Air Quality Permit No. 06-0118-ST-01 for the Jordan Cove Energy Project

To the Oregon Department of Environmental Quality:

Jordan Cove Energy Project LP (applicant) is proposing to construct and operate a new liquefied natural gas (LNG) export terminal (hereafter terminal, project, or facility) in Coos Bay, Oregon. The proposal includes a 420 megawatt power plant, natural gas cleaning systems, four liquefaction trains, liquefied natural gas (LNG) storage tanks, and LNG ship load out facilities (collectively, facility). The facility will be located on the bay side of the North Spit, along Jordan Cove Road in Coos Bay, Oregon. The Oregon Department of Environmental Quality (DEQ) has proposed a Standard Air Contaminant Discharge Permit (ACDP) authorizing emissions from the construction and operation of the project. As a new federal major source of air pollution proposed in an area that is in attainment for all criteria pollutants, the applicant must comply with the federal Clean Air Act's (CAA) Prevention of Significant Deterioration (PSD) program. Within one year of commencing operation, JCEP must also apply for a Title V operating permit to replace the ACDP.

The Northwest Environmental Defense Center, Beyond Toxics, Cape Arago Audubon Society, Cascadia Wildlands, Citizens Against LNG, Clam Diggers Association of Oregon, Friends of Living Oregon Waters, Neighbors for Clean Air, Northwest Environmental Advocates, Northwest Environmental Defense Center, Oregon Coast Alliance, Oregon Shores Conservation Coalition, Oregon Wild, Rogue Climate, Rogue Riverkeeper, Sierra Club, South Umpqua Rural Community Partnership, Umpqua Watersheds, Inc., Waterkeeper Alliance, and the Western Environmental Law Center (collectively, Commenters) submit these comments urging DEQ to take a closer look at the emissions from the applicant's proposed terminal.

Commenters have a significant interest in ensuring air quality along the Oregon coast. Commenters have members and supporters, who work, visit, recreate, or live near the site of the proposed project. Commenters are concerned that the terminal will have considerable adverse impacts on the air quality in the region and the entire state of Oregon. As a major emitter of various air pollutants, and a source of hazardous air pollutants, the facility will adversely impact air quality within the local air shed, the health of the surrounding environment and community, and the global climate.

DEQ should deny the air permit because the project will result in significant emissions of pollutants that are dangerous to human health and the environment, and because the project will frustrate Oregon's goal of reducing greenhouse gas emissions 10 percent below 1990 levels by 2020. In addition, certain aspects of the permit must be modified to conform with the requirements of the federal CAA and Oregon's State Implementation Plan (SIP) before DEQ may issue the permit.

I. DEQ should deny the air permit because the applicant's proposed facility will emit significant amounts of pollutants that are dangerous to human health and the environment.

It is the public policy of the State of Oregon "[t]o restore and maintain the quality of the air resources of the state in a condition as free from air pollution as is practicable, consistent with the overall public welfare of the state." Or. Rev. Stat. 468A.010(1)(a). The purpose of Oregon's air pollution laws is "to safeguard the air resources of the state by controlling, abating and preventing air pollution under a program which shall be consistent with the declaration of policy in this section." Or. Rev. Stat. 468A.015.

DEQ's public notice states that the facility will emit significant amounts of Particulate Matter (PM), Carbon Monoxide (CO), Sulfur Dioxide, Nitrogen Oxides, Volatile Organic Compounds, and Greenhouse Gases (GHGs). Commenters urge DEQ to assess and document the public health and other environmental impacts that will result from the proposed terminal's emissions. Based on this assessment, DEQ should deny the application.

Greenhouse Gases

EPA has defined GHGs as six well-mixed gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbon, perfluorocarbon, and sulfur hexafluoride. 75 Fed. Reg. 31514 (June 3, 2010) (Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule). GHGs trap the Earth's heat and form a greenhouse effect. Human activities "are intensifying the naturally occurring greenhouse effect by increasing the amount of GHGs in the atmosphere, which is changing the climate in a way that endangers human health, society, and the natural environment." *Id.* When these gases "are emitted more quickly than natural processes can remove them from the atmosphere, their concentrations increase, thus increasing the greenhouse effect." *Id.* Independently, emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride can also have direct adverse effects.

For example, carbon dioxide affects water efficiency of plants by increasing the carbon-to-nitrogen ratio in forages, thus reducing the nutritional value of those plants. *See, e.g.,* S.V. Krupa, *The Greenhouse effect: Impacts of ultraviolet-B (UV-B) radiation, carbon dioxide (CO2), and ozone (O3) on vegetation,* 61 Environmental Pollution 4 (1989), pages 263-393. This in turn can affect animal weight and performance for grazing livestock or wildlife. As surface waters absorb greater concentrations of carbon dioxide, the rate of photosynthesis in submerged aquatic vegetation increases. This leads to increased algal blooms and lower dissolved oxygen available to fish and shellfish. Elevated carbon dioxide concentrations also result in ocean acidification, which may affect marine ecosystems.

Particulate Matter (PM)

There are numerous negative effects of PM emissions. The size of the PM particle is directly linked to its potential to cause health problems. Coarse particles are larger than 2.5 micrometers but smaller than 10 micrometers in diameter. These are found near roadways and dusty industries and can pass through the throat and nose, entering the lungs and causing serious health effects. Fine particles are 2.5 micrometers in diameter or smaller and can form when gases emitted from power plants or industries react in the air. The EPA recognized that health studies demonstrate significant associations between exposure to $PM_{2.5}$ and premature death from heart and lung disease. *See, e.g.*, 74 Fed. Reg. 58,688 (Nov. 13, 2009). Due to their small size, $PM_{2.5}$ can penetrate deeply into the lungs when inhaled and can accumulate, react, or be absorbed into the body. At high levels, $PM_{2.5}$ is lethal. Even at very small concentrations, however, $PM_{2.5}$ can cause a myriad of adverse health impacts.

Fine particulate matter also has negative environmental impacts. For example, EPA determined that $PM_{2.5}$ impairs visibility in various locations across the country, including urban areas and Class I Federal areas such as national parks and wilderness areas. 71 Fed. Reg. 61,144, 61,203 (Oct. 17, 2006). In addition, particulate matter contributes to adverse effects on vegetation, ecosystems, climate, and causes damage to and deterioration of property. *Id.* at 61,209. Specifically, excess levels of particulate nitrate and sulfate can lead to acidifying deposition to foliage, accelerated weathering of leaf and cuticular surfaces, increased permeability of leaf surfaces to toxic materials, water, and disease agents, increased leaching of nutrients and foliage, and altered reproductive processes. *Id.* at 61,209. Ultimately these impacts weaken trees and render them susceptible to other stresses. *Id.*

Carbon Monoxide

Inhaled carbon monoxide elicits various health effects through binding to, and associated alteration of the function of, a number of heme-containing molecules, mainly hemoglobin. 76 Fed. Reg. 54294, 54298 (Aug. 31, 2011). In particular, carbon monoxide inhalation results in decreased oxygen availability to critical tissues and organs. *Id.* This can cause a reduced amount of oxygen available to key body tissues, potentially affecting organ system function and limiting exercise capacity. *Id.*

Sulfur Dioxide

The terminal's operations will also increase sulfur dioxide emissions. Sulfur dioxide is linked with a number of adverse effects on the respiratory system. *See* U.S. EPA, Six Common Pollutants, *Sulfur Dioxide*, available at http://www.epa.gov/air/sulfurdioxide/ (last accessed Feb. 23, 2015). The major health concerns associated with exposure to high concentrations of sulfur dioxide include effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. *See* U.S. EPA, AIRTrends 1995 Summary, *Sulfur Dioxide*, available at http://www.epa.gov/airtrends/aqtrnd95/so2.html (last accessed Feb. 23, 2015). High concentrations of sulfur dioxide (SO_2) can result in breathing problems for asthmatic children and adults who are active outdoors. Short-term exposure has been linked to wheezing, chest tightness and shortness of breath. Longer-term exposure to sulfur dioxide, in association with high levels of particulate matter, include respiratory illness, alterations in the lungs' defenses and aggravation of existing cardiovascular disease. In addition to public health impacts, sulfur dioxides are a major precursor to acid rain.

Nitrogen Oxides

Nitrogen oxides (NOx) are strong oxidizing agents and play a major role in the atmospheric reactions with volatile organic compounds (VOC) that produce ozone (smog). *See* U.S. EPA, Clean Air Market Programs, *Human Health and Environmental Effects of Emissions from Power Generation*, available at http://www.epa.gov/captrade/documents/power.pdf (last accessed March 19, 2015) (attached as Exhibit 1). NOx can remain in the air for days or years. *Id.* The pollutants eventually fall to the earth in either wet form (rain, snow, or fog) or dry form (gases and particles). *Id.* This can result in impaired air quality, damage to public health, degradation of visibility, acidification of lakes and streams, harm to sensitive forest and coastal ecosystems, and accelerated decay of materials, paints, and cultural artifacts. *Id.* NOx emissions can lead to acidic rain and eutrophication in many coastal ecosystems. *Id.* NOx emissions form fine particles in the atmosphere, leading to the formation of particulate matter and causing additional health problems (see particulate matter description, above). *Id.*

Volatile Organic Compounds

Volatile organic compounds (VOCs) react with nitrogen oxides and oxygen in the presence of sunlight to form ozone. *See* U.S. EPA, Six Common Pollutants, *Ground-level Ozone: Basic Information*, available at http://www.epa.gov/groundlevelozone/basic.html (last accessed Feb. 23, 2015) (hereafter "Ozone Basic Information"). EPA regulates VOCs particularly to control ground-level ozone. Ground level ozone is a prime ingredient of smog. Exposure to ground level ozone has been linked to respiratory health problems ranging from decreased lung function and aggravated asthma to increased emergency department visits, hospital admissions, and even premature death. 73 Fed. Reg. 16436 (March 27, 2008) (National Ambient Air Quality Standards for Ozone).

Ozone may also impact vegetation by causing agricultural crop loss, reduced productivity, damage to forests and ecosystems, and visible foliar injury to sensitive species. *See* Ozone Basic Information. On top of this, climate change is expected to exacerbate ozone and health impacts. *See* U.S. EPA, *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone* (April 2009), available at http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=203459 (last accessed April 3, 2015).

Hazardous Air Pollutants

The terminal will emit numerous hazardous air pollutants (HAPs) that are known or suspected to cause cancer or other serious health effects, such as birth defects or reproductive effects. Specifically, the facility will emit:

- **Hexane** - Short-term exposure to hexane causes mild central nervous system (CNS) effects, while long-term exposure is associated with polyneuropathy in humans, with numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. EPA, Technology Transfer Network – Air Toxics Web Site: Hexane (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/hexane.html (last visited Feb. 25, 2015).

- **Toluene** - Exposure to toluene also causes CNS dysfunction, in addition to narcosis, CNS depression, and irritation of the upper respiratory tract. EPA, Technology Transfer Network – Air Toxics Web Site: Toluene (July 2012), available at http://www.epa.gov/ttn/atw/hlthef/toluene.html (last visited Feb. 25, 2015).

- **Formaldehyde** - Studies have shown an association between formaldehyde exposure and lung and nasopharyngeal cancer. EPA, Technology Transfer Network – Air Toxics Web Site: Formaldehyde (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/formalde.html (last visited Feb. 25, 2015).

- **Xylenes** – Short term exposure to mixed xylenes causes irritation of the eyes, nose, and throat, gastrointestinal effects, eye irritation, and neurological effects. Long term exposure causes primarily CNS effects such as dizziness, headache, fatigue, tremors, and incoordination. EPA, Technology Transfer Network – Air Toxics Web Site: Xylenes (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/xylenes.html (last visited Feb. 25, 2015).

- **Acetaldehyde** – Acetaldehyde is a probable human carcinogen. Short term exposure can cause irritation of the eyes, skin, and respiratory tract. Long term exposure can result in symptoms similar to those of alcoholism. EPA, Technology Transfer Network – Air Toxics Web Site: Acetaldehyde (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/acetalde.html (last visited Feb. 25, 2015).

- **Ethylbenzene** – Short term exposure to ethylbenzene results in respiratory effects including throat irritation, chest constriction, irritation of the eyes, and neurological effects such as dizziness. Health effects from long term exposure are uncertain. EPA, Technology Transfer Network – Air Toxics Web Site: Ethylbenzene (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/ethylben.html (last visited Feb. 25, 2015).

- **Propylene oxide** – Propylene oxide is a probable human carcinogen, causing symptoms from eye and respiratory tract irritation to skin irritation and necrosis. EPA, Technology Transfer Network – Air Toxics Web Site: Propylene oxide (Jan. 2000), available at http://www.epa.gov/ttn/atw/hlthef/prop-oxi.html (last visited Feb. 25, 2015).

- **Benzene** – Short term exposure to benzene can cause drowsiness, dizziness, headaches, skin and respiratory tract irritation, and unconsciousness. Long term exposure can cause various disorders in the blood, adverse effects on a developing fetus, and is associated with increased incidence of leukemia. EPA, Technology Transfer Network – Air Toxics

Web Site: Benzene (Jan. 2012), available at http://www.epa.gov/ttn/atw/hlthef/benzene.html (last visited Feb. 25, 2015).

Authorizing the construction and operation of this terminal, which would be a new source of these harmful substances, is inconsistent with Oregon's policy of restoring and maintaining the quality of air resources in the state. DEQ should deny the permit.

II. DEQ should deny the permit because it authorizes a significant tonnage of greenhouse gas emissions, contrary to Oregon state policy.

As explained above, Oregon's air pollution laws exist to safeguard the air resources of the state by restoring and maintaining the quality of the air resources of the state "in a condition as free from air pollution as practicable." Or. Rev. Stat. 468A.010(1)(a). Oregon has sought to accomplish this by controlling, abating and preventing air pollution under its air permit program. Oregon's statutes state that DEQ's air program "shall be consistent with" the statute's goals. Or. Rev. Stat. 468A.015. Because this proposed permit authorizes a new source of significant GHG emissions, it is inconsistent with the goals of Oregon's air quality statutes. DEQ must deny the permit.

The scientific consensus behind climate change is unequivocal. In 2004, Oregon's Legislative Assembly found that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources and environment of Oregon" and that "[g]lobal warming will have detrimental effects on many of Oregon's largest industries, including agriculture, wine making, tourism, skiing, recreational and commercial fishing, forestry and hydropower generation, and will therefore negatively impact states workers, consumers and residents." ORS 468A.200(3), (6). In 2009, EPA determined that "greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare" and that "the body of scientific evidence compellingly supports this finding." 74 Fed. Reg. 66,496, 66,497 (Dec. 15, 2009) ("Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act").

Scientists generally agree that the climate is changing. *See, e.g.*, Intergovernmental Panel on Climate Change, Synthesis Report, *Summary for Policymakers, in* Climate Change 2014, 2 (Stocker, T.F., et al. eds., 2013) (attached as Exhibit 2) (stating that "[w]arming of the climate system is unequivocal"). Further, "[h]uman influence on the climate system is clear, and recent anthropogenic emissions of greenhouse gases are the highest in history. Recent climate changes have had widespread impacts on human and natural systems." *Id*. The Intergovernmental Panel on Climate Change warns that "[c]ontinued emissions of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system" and that "[l]imiting climate change would require substantial and sustained reductions in greenhouse gas emissions which, together with adaptation, can limit climate change risks." *Id.* at 8.

Ten years ago, Oregon's Legislative Assembly determined that "[t]here is a need to assess the current level of greenhouse gas emissions in Oregon, to monitor the trend of greenhouse gas emissions in Oregon over the next several decades and *to take necessary action to begin reducing greenhouse gas emissions* in order to prevent disruption of Oregon's economy and quality of life and to meet Oregon's responsibility to reduce the impacts and the pace of global warming." Or. Rev. Stat. 468A.200(7) (emphasis added). In 2007, Oregon adopted GHG emission reduction targets. H.B. 3543, 74th Leg., Reg. Sess. (Or. 2007). Those targets include stopping the growth of Oregon's GHG emissions and beginning to *reduce* GHG emissions by 2010, and achieving GHG levels that are 10 percent below 1990 levels by 2020. *Id.*

To achieve the 2020 target, Oregon must allow no more than 50 million metric tons (MMT) of CO2e per year. Public Utility Commission of Oregon Report, *SB 101 Progress Toward and Rate Impact of State Greenhouse Gas Emission Goals* (2014) (attached as Exhibit 2a). Because Oregon's emissions currently exceed 60 MMT per year, Oregon must reduce its GHG emissions by more than 10 MMT per year to achieve its 2020 target. *Id.* What's more, the rate of GHG emissions in Oregon has been steadily increasing since 2010. *Id.* at 7. Regulating GHG emissions, especially from large industrial sources like this proposed facility, is the first step forward for Oregon to achieve its GHG emission reduction targets.

The GHG emissions authorized under this permit will frustrate Oregon's goals to reduce the impacts and the pace of global warming. With 2,165,917 tpy of GHG emissions, the applicant's facility would take up a large portion of the emission reduction Oregon is attempting to achieve. This terminal would become the largest emitter of GHGs in Oregon once PGE Boardman ceases operation as a coal-fired electric generation plant in 2020. *Compare*, DEQ Review Report at 5 (stating this terminal will emit 2,165,917 tpy of GHG emissions), *with* DEQ Memorandum from Dick Pedersen to Environmental Quality Commission (Nov. 30, 2010) (attached as Exhibit 3) (noting that in 2010 PGE Boardman was the largest source of GHG emissions, emitting about 4,000,000 tpy). The additional CO2e per year from this terminal will push Oregon even further away from its GHG emission goals. The additional GHG emissions authorized under this permit would also be contrary to the goals of Oregon's air quality statute, to restore and maintain the quality of the air resources of the state "in a condition as free from air pollution as practicable." Or. Rev. Stat. 468A.010(1)(a).

Given the threats to public health and the environment posed by GHG emissions, Oregon's policy of addressing climate change, and growing concerns about the impacts of climate change on global warming, DEQ must deny this request for an air permit that will add a major new source of GHG emissions in the state. Short of denying the permit, DEQ must in the very least reduce the amount of GHG emissions authorized under this permit.

III. By providing notice of an incomplete application and failing to disclose all of the documents it relied on to draft this permit, DEQ has prevented meaningful comment.

In March of 2013, the applicant applied to DEQ for a new ACDP to construct and operate the proposed terminal. *See* TRC Environmental Corporation, *Jordan Cove Energy Project, L.P. PSD Air Permit Application* (March 2013, Supplemental Section May 2013) (hereafter JCEP Application). After submitting a signed Land Use Compatibility Statement from Coos County for certain portions of the project, *id.*, DEQ determined the application was complete in December of 2013. DEQ held a public comment period on the requested air permit in April of 2014. NEDC, Oregon Coast Alliance, Oregon Shores Conservation Coalition, and Cascadia

Wildlands submitted comments outlining our concerns about the adverse impacts likely to result from the project and urging DEQ to rectify various inadequacies with the permit application. *See* Comment Letter (April 15, 2014) (attached as Exhibit 4, and incorporated herein). As explained below, it does not appear that those inadequacies were ever resolved.

What's more, DEQ should not have posted the proposed permit for public review because the application lacks critical information that is required by DEQ's own regulations. An application for a new ACDP must provide, *inter alia*, a Land Use Compatibility Statement signed by a local planner. OAR 340-216-0040(1)(k). Although some portions of this project have been reviewed and approved by Coos County, key elements of the project, including the South Dunes Power Plant and Utility Corridor, have not yet been subject to review for consistency with Statewide Planning Goals or local comprehensive plan and land use ordinance provisions. *See, e.g.*, Coos County Notice of Withdrawal of Administrative Application & Subsequent Appeals (Nov. 22, 2013) (attached as Exhibit 5). There are currently no pending applications before Coos County for these determinations. Instead, these components are being reviewed as part of the Oregon Department of Energy (Energy Facility Siting Council) certification process. DEQ should not have posted this application for public review and comment since it is lacking information required by DEQ's own regulations. Pursuant to its own regulations, DEQ must determine that this application is incomplete.

The applicant has since submitted to DEQ a list of categorical insignificant activities, and information clarifying the applicant's request for an exemption from the Acid Rain Program. These last two sets of information were not made available for public comment. Under Oregon law, notice requirements are designed to (1) "inform the interested public about intended agency action," and (2) "trigger[] the opportunity for an agency to receive the benefit of the thinking of the public on the matters being considered." *Bassett v. State Fish and Wildlife Comm'n*, 27 Or. App. 639, 642 (Or. App. 1976). By failing to provide the additional materials submitted by applicant, and failing to ensure the application was complete prior to posting for public review, DEQ prevented meaningful comment. DEQ request the complete Land Use Compatibility Statement from the applicant, disclose any additional materials, and provide for an additional round of public review that is fully informed.

IV. DEQ must deny the proposed permit because the supporting analysis does not meet the minimum federal or state requirements.

To obtain a PSD permit, an applicant must (1) apply best available control technology (BACT) to minimize emissions of pollutants that may be produced by the new or modified source in amounts greater than applicable levels of significance; (2) demonstrate, through analyses of the anticipated air quality impacts associated with the proposed facility, that the emissions will not cause or contribute to an exceedance of any applicable NAAQS or air quality increment; (3) address impacts on special Class I areas (for example, certain national parks and wilderness areas); (4) assess impacts on soils, vegetation, and visibility; and (5) provide for public comment and an opportunity for a hearing. 42 U.S.C. § 7475(a). Full PSD review may also require an applicant to submit extensive air quality monitoring data and to commit to post-construction monitoring. *Id.* § 7475(a)(7); *see also* 43 Fed. Reg. 26387, 26392 (June 19, 1978) (1977 Clean Air Act Amendments to Prevent Significant Deterioration).

A. DEQ’s BACT analysis is fundamentally flawed.

As a major new source subject to the PSD program, the applicant must apply BACT for each pollutant emitted at a significant emission rate (SER) over the netting basis. OAR 340-224-0070(1). Section 169 of the CAA defines BACT as:

> an emission limitation based on the maximum degree of reduction of each pollutant . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

42 U.S.C. § 7479(3); 40 C.F.R. §§ 52.21(b)(12), 51.166(b)(12).

BACT is determined by a top down analysis. Exhibit 4 at 319-46 (U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011)). A top-down analysis starts by identifying control technologies that would achieve the Lowest Achievable Emissions Rate (LAER). The identification of available technologies is not limited to those listed on EPA’s RACT/BACT/LAER Clearinghouse, available at http://cfpub.epa.gov/RBLC/ (last accessed March 27, 2015). U.S. EPA, *New Source Review Workshop Manual* (1990), page G.3, available at http://www.epa. gov/ttn/nsr/gen/wkshpman.pdf (last visited Feb. 24, 2015) (hereafter NSR Workshop) (noting that sources for LAER include, in addition to the RACT/BACT/LAER Clearinghouse, SIP limits for a particular class or category of sources, and preconstruction or operating permits issued in other areas).

From the LAER baseline, the applicant has the burden of showing why LAER is not economically achievable. The applicant must also demonstrate what level of BACT would be achievable. *See* Exhibit 4 at 320 (stating that at step one of the BACT analysis, “[t]he top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not ‘achievable’ in that case”). Thus the control technologies that represent LAER will be considered BACT unless the permit applicant demonstrates that these control technologies are not achievable. This process results in “an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act.” NSR Workshop at B.2.

Although the applicant carries the initial burden to identify candidate control options for consideration as BACT, ultimately DEQ (as the permitting authority) must decide which emissions limitation constitutes BACT. 43 Fed. Reg. at 26397. EPA’s Environmental Appeals Board has repeatedly instructed permitting authorities that “BACT determinations are one of the most critical elements in the PSD permitting process, must reflect the considered judgment on the part of the permit issuer, and must be well documented in the administrative record.” *In re Mississippi Lime Co.*, 15 E.A.D. __, PSD Appeal No. 11-01, Slip Op. at 17 (EAB, Aug. 9, 2011) (citing *In re Desert Rock Energy Co., LLC.*, PSD Appeal Nos. 08-03 thru 08-06, slip op. at 50

(EAB, Sept. 24, 2009); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 132 (EAB 1999); *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 442 (EAB 2005); *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 363 (EAB 2002)).

The following paragraphs explain how the applicant's assessment of control technologies for GHG emissions from the combined cycle unit, and control technologies for NOx emissions from the emergency generators, is inconsistent with the minimum requirements for a BACT analysis. Therefore DEQ may not rely on the applicant's faulty analysis of BACT in its permitting decision.

The majority of the GHG contribution at an LNG terminal will come from combustion sources, such as combustion turbines, heaters, thermal oxidizers, and flares. *See* EPA, Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Freeport LNG Development, L.P., Freeport LNG Liquefaction Plant (Dec. 2013), page 10 (attached as Exhibit 6). For controlling GHG emissions from the combined cycle unit, the applicant identified only Carbon Capture and Storage (CCS), thermal efficiency, and clean fuels as available control technologies. DEQ Review Report at 10. The applicant described "thermal efficiency" as operating the combustion turbine units efficiently and conducting periodic maintenance to regain any recoverable efficiency degradation. JCEP Application at 4-12. Neither the description nor the permit specify how the units are to be operated efficiently. The applicant failed to consider numerous control technologies that have been identified by EPA as available to control GHG emissions, such as: (1) good combustion, operating, and maintenance practices; (2) use of an air intake chiller; and (3) use of an oxidation catalyst. Exhibit 6 at 11-12.[1]

In addition, the applicant failed to consider whether larger combustion turbines could have resulted in increased efficiency resulting in lower GHG emissions. The applicant is proposing six (6) combined cycle units, each with a design heat input rate of 554 MMBtu/hr. However, EPA has stated that larger combustion turbines over 850 MMBtu/hr can achieve increased efficiency. EPA has proposed that the Best System of Emission Reduction (BSER) for these units is 1,000 lbs/MWh, lower than the applicant's proposed 1,100 lbs/MWh. 79 Fed. Reg. 1430, 1446-47 (Jan. 8, 2014) (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units). Once finalized, this BSER will set the floor for the minimum allowable BACT determination.

The applicant then improperly eliminated CCS, essentially claiming that it is not feasible. The applicant relied on outdated sources for this proposition. *See* JCEP Application at 4-13 (citing to a 2010 Obama Administration Interagency Task Force report, 2011 Department of Energy research program plans, and 2010 industry statements). After those sources were published, in 2013, EPA identified CCS as a technically feasible control option for GHG emissions coming from precisely this type of LNG terminal. *See* Exhibit 6 at 12-13. Indeed, EPA has concluded that CCS should be considered as an available technology in the first step of the BACT analysis, and any elimination must include a full and detailed explanation in the record. Exhibit 4 at 335-36 (explaining that "if the permitting authority eliminates [CCS] at

[1] Commenters note that EPA's BACT analysis for the Freeport LNG facility was lacking in its own right, but JCEP's BACT analysis fails to achieve even this weaker level of scrutiny.

some later point in the top-down analysis, the grounds for doing so should be reflected in the record with an appropriate level of detail.").

What's more, the applicant glosses over the variations of CCS, referencing in general the control technologies that have been applied to petroleum refining, natural gas processing industries, and exhausts from gas-fired industrial boilers. JCEP Application at 4-13. This ignores the variations of carbon capture technologies that are available: pre-combustion capture, post-combustion capture, and oxyfuel combustion. *See* IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III, Metz, B., O. Davidson, H.C. de Conick, M. Loos, and L. A. Meyer (eds.) (Cambridge University Press) (excerpt attached as Exhibit 7). The applicant is correct to note that pre-combustion capture is applicable primarily to gasification plants and likely inappropriate for an LNG facility. Post-combustion capture, however, is applicable to combustion turbines. Exhibit 7 at 12. It is also one of the most effective technologies, achieving up to 90% control. *Id.* at 12-13. Another option that the applicant failed to consider is partial CCS. Under partial CCS, one would capture emissions from the pipeline gas pretreatment stream but ignore combustion emissions. Because pretreatment emissions are almost pure CO2, they are much easier to deal with than combustion emissions.

EPA instructs that "permitting authorities must ensure that their impacts analysis fully considers the relevant facts and concerns for the facility at issue and that the support for the environmental, economic, and energy choices made during the impacts analysis of the BACT determination is well-documented in the permit record." Exhibit 4 at 346. DEQ has failed to do so here. Because CCS has been identified as an available and feasible control technology for GHG emissions from LNG terminals, the applicant's BACT analysis is inadequate and DEQ must analyze CCS as a potential control technology. When DEQ does perform the necessary BACT analysis, if it chooses to eliminate a control option on economic grounds, it must "demonstrate that the costs of pollutant removal for the particular option are disproportionately high." Exhibit 4 at 345. This is because the cost effectiveness numbers ($/ton of CO_2e) for the control of GHG are likely to be much lower than the cost effectiveness of controls for criteria pollutants, which have had more time to evolve.

The applicant's BACT analysis for the seven diesel internal combustion engines (emergency generators) is likewise flawed. For the emergency generators, the applicant determined BACT for NOx emissions would be limited hours of operation (200 hours per year each) and good combustion practices. JCEP Application at 4-17. The applicant listed Selective Catalytic Reduction (SCR) in its initial identification of possible controls. SCR is an add-on NOx control technique that is placed in the exhaust stream following the gas turbine/duct burner.

The applicant ruled out SCR for two reasons. First, the applicant stated that add-on controls are not cost effective for small emergency diesel engines that operate less than 500 hours per year. Second, the applicant claimed add-on techniques would be ineffective, based again on limited hours of operation. With fewer hours of operation, the SCR would never reach the operating temperature required to remove any substantial NOx emissions. Both of these justifications rely on the assumption that the emergency generators will be used for a limited number of hours. DEQ's permit terms, however, expressly state that "[t]here is no time limit on the use of emergency stationary ICE in emergency situations." Permit No. 06-0118-ST-01 Condition 64, page 25. There is no support for the applicant's assumption that the emergency generators will be used for a maximum of 200 hours per year each. In fact, DEQ's permit suggests otherwise. Further undermining the analysis, DEQ never defines what constitutes an emergency (see additional discussion on DEQ assumptions, below). Ultimately, the applicant concluded that no add-on control technology constitutes BACT for the seven emergency generators. This analysis is wholly flawed. DEQ should select SCR as BACT for the NOx emissions from the emergency generators, or in the very least require the applicant to provide an adequate basis for eliminating SCR as BACT.

At bottom, the applicant failed to meet its burden to justify in the record why the technologies it chose to eliminate are not available or achievable. Absent this justification, EPA's guidance supports that DEQ should select the top-ranked options as BACT. Here, that would be CCS for GHG emissions from the combined cycle unit, and SCR for NOx emissions from the emergency generators, as just two examples. In the very least, DEQ must require additional analysis from the applicant that comports with the top down approach to support the final determination of BACT for each pollutant from each emission unit.

B. <u>The applicant failed to demonstrate that the anticipated emissions will not cause or contribute to an exceedance of the NAAQS or applicable PSD increments.</u>

Under OAR 340-224-0070(2), an applicant of a source subject to the PSD program must conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source. The purpose of this analysis is to demonstrate that the new emissions, when combined with other applicable emissions increases and decreases from existing sources, will not cause or contribute to a violation of any applicable NAAQS or PSD increment. NSR Workshop at C.1. A typical air analysis consists of an assessment of existing ambient air quality, and predictions of ambient concentrations that will result from the proposed project and future growth associated with the project. *Id.* at C.1-C.2.

This terminal has the potential to emit NOx, SO_2, ozone (as VOC), PM/PM_{10}/$PM_{2.5}$, CO, GHG (as CO_2e), and H_2SO_4 at levels that exceed the pollutant specific PSD significant emission rates established by DEQ's rules. *See* OAR 340-200-0020, Table 2 (attached as Exhibit 8). *See also* DEQ Review Report at 20. Pursuant to OAR 340-222-0041(3)(b)(C), the applicant completed an air quality impact analysis to demonstrate that emissions from the proposed facility will not violate the NAAQS or PSD increments. JCEP Application, Appendix B.9.

The applicant's analysis is inadequate for several reasons. First, DEQ improperly allowed the applicant to base its analysis of ambient air quality on atmospheric dispersion modeling to estimate the maximum expected air quality impacts, rather than requiring preconstruction monitoring as required by DEQ's own rules. Second, DEQ failed to provide a basis for many of the assumptions included in the applicant's analysis. Third, the air quality analysis fails to consider all possible sources of emissions, and thus DEQ must not rely on the applicant's faulty calculation of the terminal's potential to emit. Finally, DEQ must not accept the applicant's Class II or Class I area analyses because as it is fundamentally flawed.

1. *DEQ improperly waived the requirement for preconstruction air quality monitoring without a sufficient basis.*

For each pollutant that triggers PSD, Oregon's SIP and federal regulations require preconstruction air quality monitoring to assess the existing ambient air quality in the area, and to determine whether the proposed ambient concentrations that will result from both the addition of the proposed new source and associated future growth will cause or contribute to a violation of the NAAQS or exceed the PSD increment. 40 CFR 52.21(m)(1); OAR 340-225-0050(4). Under OAR 340-225-0050(4)(C), DEQ "may exempt the owner . . . from preconstruction monitoring for a specified pollutant if the owner . . . demonstrates that the air quality impact from the emissions increase would be less than the amounts listed [in the section] or that modeled competing source concentration (plus General Background Concentration) of the pollutant within the Source Impact Area are less than" the significant monitoring concentrations listed in the rule. *See also* 40 CFR § 52.21(i)(5) (authorizing a preconstruction monitoring waiver if "(i) [t]he emissions increase of the pollutant from the new source . . . would cause" air quality impacts less than specific concentrations, "(ii) [t]he concentrations of the pollutant in the area that the source . . . would affect are less than" the specific concentrations, or "(iii) [t]he pollutant is not listed").

DEQ's rules and federal regulations allow the agency to waive preconstruction air quality monitoring for each particular pollutant emitted above a significant emission rate only under specific circumstances. Under DEQ's rules, the applicant has the burden to demonstrate that the air quality impact from the new source emissions increase would be less than the significant ambient air quality impact level listed in the rule, or that the modeled competing source concentration (plus General Background Concentration) of the pollutant within the Source Impact Area is less than the listed significant ambient air quality impact level. The applicant's request for a preconstruction monitoring waiver failed to make that demonstration. Despite this lack of showing, and although the permit and the review report do not specifically state it, DEQ apparently waived the monitoring requirement for all of the pollutants triggering PSD review,[2] without providing a justification or explanation for each.

In its request for a waiver, the applicant recognized that the terminal is projected to have emission rates in excess of the significant emission rates (SERs) for CO, NO_x, SO_2, particulates, the ozone precursor VOC, and sulfuric acid mist (H_2SO_4). JCEP Application, Appendix D, Letter from Darin Ometz, TRC, to Phil Allen, DEQ (Jan. 28, 2013). The applicant requested a waiver for H_2SO_4 because there are no approved ambient monitoring techniques for those emissions. *Id.* This is not a proper basis for a waiver. Without the requisite demonstration of projected impacts from H_2SO_4 emissions, DEQ must not authorize a preconstruction monitoring waiver for H_2SO_4.

Because GHG emissions are not listed in OAR 340-225-0050(a)(C), DEQ was within its authority to waive the associated air quality monitoring requirements. *See also* 40 C.F.R. § 52.21(i)(5)(iii).

[2] NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$, SO_2, H_2SO_4, and GHG emissions.

Although there is no *de minimis* air quality level for ozone in the federal regulations or DEQ's rule, "any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data." 40 C.F.R. § 52.21(i)(5)(i), note. DEQ's rules further state that for ozone, the "requirement for ambient air monitoring may be exempted if existing representative monitoring data shows maximum ozone concentrations are less than 50% of the ozone NAAQS based on a full season of monitoring." OAR 349-225-0050(4)(C)(vi). Neither DEQ nor the applicant analyzed the terminal's air quality impact for ozone, contrary to what DEQ's own rules require. DEQ must require preconstruction monitoring for VOCs.

Finally, the applicant incorrectly stated that a waiver may be granted if existing quality-assured ambient air quality data exists from alternate locations that are representative of, or conservative, as compared to conditions at the proposed facility location. JCEP Application, Appendix D, Letter from Darin Ometz, TRC, to Phil Allen, DEQ (Jan. 28, 2013). Federal regulations and DEQ's own rules do not provide this as a basis for a waiver. Because this is inconsistent with federal regulations and DEQ's own rules, DEQ's general waiver for preconstruction monitoring of CO, PM_{10}, NO_2, and SO_2 was inappropriate.

DEQ may not rely on random monitoring stations throughout the state of Oregon as a substitute for determining the ambient concentration of each of the triggering pollutants in Coos Bay, Oregon. DEQ justified its waiver because "representative or conservative background was available," DEQ Review Report at 26, referring also to 40 C.F.R. § 52.21 and guidance from the NSR Workshop (at 8). EPA has explained that the monitoring location, quality of the data, and currentness of the data are all critical to determining whether data are representative. EPA, Ambient Monitoring for Prevention of Significant Deterioration (PSD) (May 1987) (attached as Exhibit 9). For location, EPA states that existing monitoring data should be representative of (1) the location of maximum concentration increase from the proposed source, (2) the location of maximum air pollutant concentration from existing sources, and (3) the location of the maximum impact area (where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification). Exhibit 9 at 6.

In its request for a waiver, the applicant cited to "the closest monitoring sites" to the terminal location "to represent the current background air quality in the site area." JCEP Application, Appendix D, Letter from Darin Ometz, TRC, to Phil Allen, DEQ (Jan. 28, 2013). In turn, DEQ blindly relied on this data in the permit and review report. *See* DEQ Review Report at 26-27 (identifying a Eugene monitoring station (EPA AIRData # 41-039-0013) as representative of the ambient concentration of CO and PM_{10}, a Cottage Grove station (EPA AIRData # 41-039-9004) for $PM_{2.5}$, and a Portland station (EPA AIRData # 41-051-0080) for NO_2 and SO_2). *See also* Google Earth Map, Jordan Cove LNG Air Impacts (attached as Exhibit 10) (mapping the location of the proposed site in relation to the location of the monitoring stations that the applicant relied on for ambient air quality data). The only justification DEQ provided is that all of these monitors are within or nearby the two largest cities in Oregon with a substantially greater level of mobile and point source air emissions compared to the terminal site in Coos Bay, and therefore are conservative representations of the air quality in the project area. DEQ Review Report at 27. This justification is wholly inadequate.

DEQ failed to assess the type and impact of existing sources for each pollutant in the area of the proposed terminal, and how those impacts compare to the chosen representative monitoring locations. *See* NSR Workshop at C.18 (noting that "[if the location of the proposed source . . . is not affected by other major stationary point sources, the assessment of existing ambient concentrations may be done by evaluating available monitoring data," but noting that even then, it is preferable to use data collected within the area of concern). Without such an assessment, it is unreasonable for DEQ to conclude that the monitoring locations, some more than 200 miles from the site location and in a completely different topographical region, are conservative representations. DEQ also ignored other critical factors, such as the size of the areas monitored by each location as compared to the size of the area that will be impacted by this terminal, relative distribution of ground level and elevated sources, and distances between impact areas and contributing sources.

For example, the Oregon International Port of Coos Bay is host to marine vessels, a large source of emissions near proposed terminal site. Marine vessel emissions offshore also impact the air quality along Oregon's coast. *See, e.g.*, EPA, *Designation of North American Emission Control Area to Reduce Emissions from Ships*, EPA-420-F-10-015 (March 2010), page 3 (explaining that "ships generate significant emissions of fine particulate matter (PM2.5), NOx, and SOx that contribute to nonattainment of the National Ambient Air Quality Standards for PM2.5 and ozone" and "also cause harm to public welfare") (attached as Exhibit 11). The same marine vessel sources of emissions are not present near the monitoring locations in Eugene or Cottage Grove. Coos Bay is also home to the Southwest Oregon Regional Airport, located just across the bay from the site of the proposed terminal. The monitoring stations in SE Portland and Cottage Grove do not reflect this type of activity, and therefore would not be conservative alternatives for monitoring data. It is unreasonable for DEQ to claim the monitoring stations in Eugene, Portland, or Cottage Grove represent conservative data. At bottom, DEQ's conclusions are overly broad and general to provide sufficient justification for the chosen sites.

The NSR Workshop states that site-specific preconstruction air quality monitoring could be required of the applicant "[i]n the absence of available monitoring data which is representative of the area of concern." NSR Workshop at C.16. It goes on to explain that "[i]f a potential threat to the NAAQS is identified by the modeling predictions, then continuous ambient monitoring data should be required, even when the predicted impact of the proposed project is less than the significant monitoring value" and that "[t]his is especially important when the modeled impacts of existing sources are uncertain due to factors such as complex terrain and uncertain emissions estimates." NSR Workshop at C.18. DEQ may not rely on the representative "regional" sites as a substitute for air quality monitoring of existing ambient concentrations for the triggering pollutants. This is precisely the type of situation where DEQ must require preconstruction air quality monitoring.

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2. DEQ failed to provide a basis for many assumptions.

In addition to the general application information required for an ACDP, OAR 340-216-0040, an applicant must submit to DEQ "all information necessary to perform any analysis or make any determination required under" the air quality analysis rules. OAR 340-225-0030. Assumptions used in modeling, such as the hours of operation, hours needed for start up and shut down, and what constitutes an emergency, must be included in the permit application. Yet DEQ accepted many of the applicant's assumptions without questioning their basis. The public is left to wonder how the applicant or DEQ arrived at their conclusions. The lack of justification is extremely problematic since many of these assumptions form the basis for DEQ's determination of the terminal's potential to emit, and determination that the terminal will not cause or contribute to a violation of the NAAQS or a PSD increment. The following are just a few of the assumptions DEQ improperly relied on when proposing the permit.

Worst case scenario

DEQ assumed without justification that the terminal will operate at full capacity, and that operations at full capacity will result in the greatest emissions ("worst-case scenario"). For example, DEQ identified year-round full load operation of each combustion turbine would be the "worst-case operating scenario" for the combustion turbines. DEQ Review Report at 24. Constant operation at full load, however, is actually the *most efficient* scenario for emissions of certain pollutants. *See, e.g.*, Exhibit 4 at 32 (EPA, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, *3.1 Stationary Gas Turbines* (April 2000)) (explaining that "CO and VOC emissions both result from incomplete combustion" and thus "a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide" whereas "a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide"). This is also true for HAP emissions. *Id.* at 3.1-5 ("Similar to CO emissions, HAP emissions increase with reduced operating loads."). Although operating under a full load produces greater fuel efficiency (attractive to an applicant seeking to maximize profit), full load does not in fact represent the worst-case scenario for CO and HAP emissions. DEQ improperly relied on the applicant's assumption that full load represents the "worst-case operating scenario" and thereby ignored additional CO and HAP emissions.

In reality, the liquefaction plant's rate of operation will depend on variables such as changes in customer demands and variations in natural gas supply. *See, e.g.*, FERC, Jordan Cove Energy and Pacific Connector Gas Pipeline Project Draft Environmental Impact Statement, EIS 0256D (Nov. 2014), page 1-13 (hereafter Jordan Cove DEIS) ("According to Jordan Cove's application, the Project is a market-driven response to the increasing availability of competitively priced natural gas from western Canadian and Rocky Mountain sources, and robust international demand for natural gas."). Changes in supply and demand will result in variations in the load for the combustion turbines. Frequent load changes will lead to different emission levels. Exhibit 4 at 31 ("With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion."). DEQ ignored frequent load changes as a variable in determining the worst-case scenario.

DEQ only considered three load variations for its emissions estimates. *See* DEQ Review Report at 24. By only evaluating three different constant loads, DEQ is missing additional emissions that are likely to result under frequent load changes, as well as varying frequencies of duct firing. In the emissions summary DEQ noted that the potential annual emissions from the combined cycle units assume the equivalent of 4,000 hr/yr of duct firing. DEQ Review Report at 6. There is no justification for this number, which served as part of the basis for DEQ's potential emissions calculation for the largest source of GHGs at the terminal. DEQ must explain how it accounts for variations in the frequency of load changes and duct firing to arrive at its emissions calculation for the combustion turbines. The resulting potential to emit calculations fail to account for the additional emissions that will be caused by frequent changes in load, instead improperly assume full operating capacity should be the basis for determining the terminal's potential to emit.

Maximum capacity

Based on conflicting information, DEQ should not assume the applicant's claimed capacity of 1.1 billion cubic feet (bcf) per day and 6 million tons annually of LNG is accurate. In February of 2014, Canada's National Energy Board granted the applicant a 25-year license authorizing the export of up to 1.55 Bcf/d of natural gas to the United States. *See* Canadian Ruling (Feb. 20, 2014), available at https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=2423890&objAction=browse&viewType=1 (last accessed April 3, 2015) ("Jordan Cove LNG seeks a licence duration of 25 years, starting on the date of first export with an annual volume of 16.03 billion cubic metres ($10^9 m^3$) of natural gas, which corresponds to a natural gas equivalent of 1.55 billion cubic feet per day (Bcf/d), and a maximum quantity of 442.68 $10^9 m^3$ over the term of the licence."). On March 18, 2014, the U.S. Department of Energy authorized the applicant to import up to 565.75 Bcf/year of natural gas from Canada (amounting to 1.55 Bcf/day). *See* U.S. Department of Energy, Order No. 3412, Jordan Cove LNG LP Application for long-term authority to import natural gas by pipeline from Canada (March 18, 2014) (FE Docket No. 13-141-NG), available at http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2014/ord3412.pdf (last accessed April 3, 2015) (allowing "long-term, multi-contract authorization to import natural gas from Canada in a total volume of 565.75 billion cubic feet per year (Bcf/yr), or 1.55 Bcf/day for a 25-year term").

Information from Calgary Herald articles with interviews with Don Althoff, Veresen President and CEO, suggest that this terminal may have capacity for 9 million tons per year, a fifty percent increase from the volume proposed in the air permit application. *See* Dan Healing, Calgary Herald, *Pipeline stake expected to fuel Veresen LNG project* (Sept. 21, 2014) (attached as Exhibit 12) ("The LNG project is to have an *initial capacity of six million tonnes per year, expandable to nine million*. The Ruby pipeline's current capacity is 1.5 billion cubic feet per day but it can be *expanded to two billion* with additional compression, Veresen said.") (emphasis added). *See also* Dan Healing, Calgary Herald, *Court rules investor can buy into Jordan Cove LNG project* (Feb. 27, 2015) (attached as Exhibit 13) (The terminal "is to have an initial capacity of six million tonnes per year or one billion cubic feet per day and *can be expanded by 50 per cent*.") (emphasis added).

The analysis in the DEIS prepared by FERC also supports a greater capacity for the terminal. Jordan Cove DEIS at 2.1.2.1 ("The pipeline would have a design capacity of 1.07 Bcf/d of natural gas, assuming a receipt pressure of about 900 psig at the supply interconnections near Malin, and a delivery pressure of 850 psig at the proposed Jordan Cove LNG terminal at Coos Bay. The maximum allowable operating pressure (MAOP) of the pipeline would be 1,480 psig."). Thus the applicant will be able to run fifty percent more gas through the 36-inch pipeline if the applicant compresses the gas at a higher rate.

It is impossible to calculate the terminal's potential to emit, much less provide meaningful comment, when the volume of LNG proposed for export seems to be on a sliding scale. DEQ should question the maximum capacity number, given Veresen's apparent intent to move 1.65 bcf/day and 9 million tons annually of LNG. Verifying the accurate volume is essential because the maximum capacity serves as a basis for the applicant's potential to emit calculations, the values of which become the plant site emission limit (PSEL) for many of the terminal's pollutant emissions.

Monitoring locations for representative ambient air quality data

DEQ assumed without explanation that the applicant's chosen representational monitoring locations accurately reflect ambient concentrations in the Coos Bay region. As explained above, the applicant unreasonably relied on monitoring locations more than 200 miles away from the proposed terminal site to form the basis of the competing source analysis. *See* DEQ Review Report at 32; Exhibit 10. This analysis served as the basis for the applicant's assertion, and DEQ's determination, that emissions from the new terminal will not cause or contribute to a violation of the NAAQS or a PSD increment.

Thermal oxidizer destruction efficiency

DEQ failed to provide a basis for its statement that the thermal oxidizers have a destruction efficiency of greater than 99.5 percent for sulfuric acid mist, VOC and hydrocarbon. DEQ Review Report at 24.

Emergency generators

The permit allows for certain emergency operations, but fails to define what constitutes an emergency. Operation of many of the emergency sources in non-emergency situations is limited to 50 or 100 hours as part of the BACT determination. *See, e.g.*, Permit Condition 64. Those limits are meaningless without a definition of what constitutes an emergency. DEQ's definitions are too vague to resolve the ambiguity. OAR 340-200-(4) (defining "emergency" as "any situation arising from sudden and reasonably unforeseeable events beyond the control of the owner or operator, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit"). Without a more complete definition for what constitutes an emergency, the BACT limitations on hours of usage outside of "emergency" situations are meaningless. Justification is lacking for the assumed operating hours for the emergency diesel generator, fire pump operations, and TO vents. DEQ Review Report at 6.

3. *The applicant's calculation of likely emissions fails to consider all possible harmful sources.*

An application for an ACDP must include, *inter alia*, a description of the production processes and related flow chart, a plot plan identifying the air contaminant sources, and an estimate of the amount and type of each air contaminant emitted by the source. OAR 340-216-0040. Here, the applicant failed to provide sufficient information because it failed to identify all air contaminant sources.

Additional terminal components

DEQ's public notice states that the facility will consist of a power plant, natural gas cleaning systems, four liquefaction trains, liquefied natural gas (LNG) storage tanks, and LNG ship load out facilities (marine terminal). The permit identifies the following as emissions units regulated by the permit: six 70 mega watt combined cycle gas turbines with duct burners (EU1-6), South Dunes fire pump (EU7), liquefaction area fire pump (EU8), emergency generators (EU9), two feed gas cleaning and dehydration trains (EU10), flares (EU11), and LNG storage tanks (EU12). Permit No. 06-0118-ST-01 Condition 3. DEQ's fact sheet states that the terminal will also include a regional emergency response center adjacent to the power plant, upgrades to surrounding road infrastructure, and temporary housing near the job site for about 2,000 construction workers. DEQ's list of emission units and the emissions summary, however, ignore these additional aspects of the terminal.

The applicant also plans to add 2 additional liquefaction trains in the third year of operations. This additional liquefaction capacity should be included when identifying air contaminant sources and calculating the potential to emit, since it is already planned.

Amine and dehydration systems

The applicant explained each of the two gas conditioning trains will have a CO2 removal process which utilizes a primary amine to absorb CO2, and each train will process 460 MMscf/day of natural gas. JCEP Application at 2-2. Acid gas from the amine treating system (Amine Stripper) will be sent to a thermal oxidizer to oxidize sulfur components, and the thermal oxidizer is assumed to have a 96% reliability. *Id.* As noted above, the applicant did not provide a basis for this assumption. The applicant did note that "[i]n the unlikely event of thermal oxidizer downtime, the waste gas will vent to the atmosphere." *Id.* But despite the venting, "[a]ir emissions from the amine and dehydration systems are not expected." *Id.* In turn, DEQ stated that "emissions from the amine and dehydration systems are not expected." DEQ Review Report at 23. Yet these systems will be a source of CO2 and sulfur compounds if and when the thermal oxidizer has a downtime.

Plus, the separation of CO2 in the incoming gas stream to the amine will be a large source of CO2 emissions. Using a membrane technology instead of the amine system would result in fewer emissions. But DEQ did not even require the applicant to consider membrane technology because it improperly discounted all emissions from the amine and dehydration system. DEQ may not accept the applicant's broad assertions and must analyze the likely emissions from the amine and dehydration systems.

Refridgerant compounds

DEQ did not analyze refrigerant compounds used in the liquefaction process, such as hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs). These compounds have global warming potentials (GWPs) hundreds to thousands of times greater than CO2 and methane. *See* EPA Global Warming Potential of ODS Substitutes, Exhibit 4 at 9. *See also* Exhibit 4 at 310-11 (listing HFCs and PFCs as two of the six gases encompassed by the definition of GHGs). A more thorough analysis of air emissions is required to address the HFCs and PFCs. DEQ must also consider refrigerant alternatives identified by EPA as acceptable substitutes for ozone-depleting substances, the most recent of which was published on October 21, 2014. *See* EPA Substitute Refrigerants Under SNAP as of October 21, 2014 (attached as Exhibit 14); Exhibit 4 at 13.

Marine vessels and trains stationed at the terminal

DEQ's fact sheet states that an application for an ACDP to construct the terminal and power plant must include an estimate of the emissions from the LNG facility, power plant, and LNG carriers. *See* DEQ Fact Sheet: Jordan Cove Energy Project (attached as Exhibit 15). The only place the applicant considered the additional emissions that will result from the proposed LNG carriers was in the competing source air quality analysis. Classifying the marine vessel emissions as a competing source ignores the reality that the additional marine vessels and corresponding additional emissions will not exist but for the terminal.

Focusing on the competing source analysis that includes additional marine vessel traffic, the applicant appears to have underestimated the number of marine vessels that will arrive at the terminal annually. DEQ assumed the terminal will receive approximately 90 marine vessels each year. DEQ Review Report at 4. A breakdown of the numbers, however, shows why this number is likely too low. FERC's DEIS states that 148,000 m^3 vessels are "the largest vessel authorized by the Coast Guard to call on the LNG terminal." Jordan Cove DEIS at 4-367. The applicant proposed to export 6 million metric tons per annum (MMTPA) of LNG. DEQ Review Report at 4. *See also* Jordan Cove DEIS at 1-13 ("The newly proposed liquefaction terminal is designed to produce about 6 MMTPA (equivalent to about 0.9 Bcf/d of natural gas), and Jordan Cove intends to export that LNG by loading it onto vessels for overseas transport."). Exporting the applicant's estimated .9 Bcf/d of gas using marine vessels with a capacity of 148,000 m^3 would require at least 105 marine vessels.[3] Even that is a conservative estimate, considering the heel of LNG that is left in each tank to keep the tanks cold even when they are empty. *See* California State Land Commission (CSLC) (2006) Cabrillo Port LNG Deepwater Port Revised Draft Environmental Impact Report, page 2-21 (stating that "Of this volume, an estimated 4 million gallons (15,100 m3) would be consumed by the carrier while in transit for fuel and for maintaining the cold tanks; the remaining 32.5 or 51.5 million gallons (123,000 or 195,000 m3) would be transferred to the FSRU.").

[3] *See, e.g.*, Iowa State University Extension and Outreach: Natural Gas Measurements and Conversions, available at www.extension.iastate.edu/.

Setting aside the low estimate of 90 large LNG tanker ships, emissions from the marine vessels and rail cars while they are stationed at the LNG export terminal should be included in the direct emissions calculations. DEQ interpreted its regulations to exempt combustion emissions from the LNG vessels during hoteling, berthing, and de-berthing, stating that such activities are not considered direct emissions because the South Dunes Power Plant will provide the power to load the LNG from the liquefaction facility. DEQ Review Report at 23. In Oregon, "stationary source means any building, structure, facility, or installation at a source that emits or may emit any regulated air pollutant." OAR 340-200-0020(141). When marine vessels are docked and trains idle at a stationary source to further the purpose of the stationary source (here, completing the LNG transfer operations), the emissions from those vessels and rail car engines do come from the source itself (a transloading operation) and should be directly attributed to terminal.

Indeed, on January 17, 2008, DEQ determined that:

> [E]missions from LNG carriers that are directly associated with terminal activities are part of the stationary source's emissions. Emissions from the LNG carriers that are directly associated with terminal activities include, but are not limited to: emissions attributable to providing power for the ship-board LNG transfer system, including pumps used to transfer liquid or vapor LNG to or from the carrier; fugitive emissions from ship-board LNG piping and pumping systems; and *any other emissions that can be directly attributed to terminal activities*.

See Jordan Cove Energy and Pacific Connector Gas Pipeline Project, Final Environmental Impact Statement: Volume I 4.11-9 (emphasis added).

DEQ includes emissions associated with pumping the LNG to and from vessels as fugitive emissions, which are part of the direct potential emissions calculation. There will also be significant emissions from the vessels that do not result from pumping or transferring LNG to or from the carrier. DEQ must include these emissions in its potential emissions calculation.

The DEIS states that the LNG ship engines would be running the entire time the ship is at the marine berth due to hotelling activities as well as running the ballast water pumps. DEIS at 4-367, 4-368. According to FERC's DEIS, the LNG vessels would have to pump out 9.2 million gallons of ballast water during the loading cycle to compensate for 50 percent of the mass of the LNG cargo loaded. *Id.* at 4-366. The analysis in the DEIS goes on to say that a typical LNG vessel has three ballast water pumps. Further, "hotelling operations require the generation of 1.9 MW of power during the entire time that the LNG vessel remains in the slip" and each "vessel is anticipated to be within the slip for a total of 17.5 hours." *Id.* at 4-367. DEQ's draft permit fails to account for the emission of air pollutants that will result from these activities even though these emissions will occur while the marine vessel is docked in Coos Bay and will have immediate and direct adverse impacts on air quality.

Including emissions from mobile sources as primary emissions when the mobile sources are located at the terminal site and involved in the industrial process is not only consistent with

Oregon law, but also with federal policy. Although federal policy decisions regarding ship and train emissions do not directly control here, where DEQ implements its own CAA program under its SIP, federal case law and EPA's guidance documents are instructive in understanding how a court would interpret Oregon's regulations implementing the CAA.

In 1980, EPA promulgated a definition of stationary source that would "encompass the activities of a marine terminal and only those dockside activities that would serve the purpose of the terminal directly and would be under the control of its owner or operator." *Natural Resource Defense Council v. U.S. Envtl. Prot. Agency*, 725 F.2d 761, 765 (D.C. Cir. 1984) (quoting 45 Fed. Reg. 52,696 (1980)). Under this definition, dockside activities were limited to "those activities in which ships would engage while docked at the terminal . . . [and which] would directly serve the purpose of the terminal, such as loading and unloading . . . [and] over which the owner or operator of the terminal would have control." *Id.* "On June 25, 1982 EPA revoked the vessel emissions requirements in their entirety," meaning that emissions from docked vessels could never be considered direct emissions. *Id.* In *NRDC v. USEPA*, the D.C. Circuit vacated EPA's new regulations. *Id.* at 766-67. Looking at the statutory language and the legislative history of the 1977 amendments, the court disagreed with EPA that EPA could never regulate emissions from docked vessels because they were mobile sources. *Id.* at 768-71.

Since, *NRDC v. USEPA*, EPA has considered emissions from vessels when berthed at port in furtherance of the onshore facility to be attributable to the stationary source's potential to emit calculations. In 1990, John Calagni, the Director of the Air Quality Management Division for EPA Region VI, wrote a letter to the President of Waid and Associates explaining EPA's position on emissions from docked vessels. *See* Jan. 8, 1990 Letter from John Calagni to Ken Waid, Exhibit 4 at 403). This letter briefly covers the history of EPA's regulations governing emissions from vessels and the outcome of the *NRDC* case.

As a result of the *NRDC* case "the August 7, 1980 PSD regulations (with the exception of to and fro emissions counting) shall apply to determinations on how to treat vessel emissions." *Id.* at 2. The letter notes that the preamble to the 1980 regulations explain that "emissions from certain activities of a ship docked at a terminal (i.e., when the vessel is stationary) may be considered emissions of the terminal if the activities would 'directly serve the purpose of the terminal and be under the control of its owner or operator to a substantial extent.'" *Id.* EPA has consistently maintained this position since the NRDC case. Exhibit 4 at 405 (Oct. 28, 2003 Letter from Charles J. Sheehan to Michael Cathey and Diana Dutton, in EPA Title V Policy and Guidance Database) (stating that vessel emissions associated with LNG regasification *in addition to* the transfer of gas to the port should be included in the applicability determinations for CAA preconstruction and operating permits).

Even if DEQ chooses not to identify these emissions as direct emissions from the stationary source, they still qualify as secondary emissions and ultimately must be included in the potential emissions calculations. Secondary emissions are those "that are a result of the construction and/or operation of a source or modification, but that do not come from the source itself." OAR 340-200-0020(109). Further, secondary emissions may include "[e]missions from ships and trains coming to or from the facility." OAR 340-200-0020(109)(a). Oregon's regulations require secondary emissions to be included in PSD emissions calculations once the “major source” threshold has been met. OAR 340-224-0100 (“Once a source or modification is identified as being major, secondary emissions are added to the primary emissions”). Because this facility qualifies as a major source based on the NOx, CO, and PM emissions from the combined cycle units of the South Dunes Power Plant alone, the terminal’s secondary emissions must be added to the primary emissions.

Therefore, whether considered as primary or secondary emissions, DEQ must include emissions from LNG vessels docked at its terminal and trains idling at the site in the direct emissions calculations. DEQ may not shirk this requirement simply because one aspect of the vessel on-loading operation will be powered by the South Dunes power plant. Rather, DEQ must include all emissions from all LNG vessel activity and idling train cars at the terminal in its direct emissions calculations.

HAP emissions

DEQ may not rely on the applicant’s improper estimate of Hazardous Air Pollutant (HAP) emissions. The CAA regulates the emission of HAPs from stationary sources under the National Emission Standards for Hazardous Air Pollutants (NESHAPs) program. 42 U.S.C. § 7412. The CAA defines HAPs as any air pollutant listed under § 112(b). 42 U.S.C. § 7412(a)(6). A HAP is a pollutant that is not covered by the NAAQS and which “causes or contributes to air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious, irreversible or incapacitating irreversible illness.” *U.S. v. Walsh*, 783 F.Supp. 546, 552 (W.D. Wash. 1991). Given the increased risks associated with exposure to HAPs, Congress set relatively low emissions thresholds to trigger the NESHAPs program for major sources.

The CAA defines a “major source” under the NESHAPs program as “any stationary source or group of stationary sources” that “emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.” 42 U.S.C. § 7412(a)(1). Major sources that meet the threshold are required to meet the Maximum Achievable Control Technology (MACT) as determined by the U.S. Environmental Protection Agency (EPA) Administrator, and failure to do so results in a violation of the CAA. 42 U.S.C. § 7412(g)(2). The MACT requirement applies after the promulgation of emissions limitation standards for specific HAPs by the EPA. 42 U.S.C. § 7412(d).

Here, the applicant reported that the proposed combustion turbines, duct burners, emergency generators, South Dunes fire pump, liquefaction area fire pumps, thermal oxidizers, and flares will emit 40 different types of HAPs in the form of either VOCs, Polycyclic Organic Compounds (POM), or Metal-HAPs. JCEP Application, Table B-12. The application claimed the facility will emit 2.5 tons per year (tpy) for a maximum individual HAP (Hexane) and 8.9 tpy of total HAPs for all 40 pollutants taken together. The three highest single HAP emissions would be Formaldehyde (1.7 tpy), Hexane (2.5 tpy), and Toluene (1.9 tpy). Congress included all three of these HAPs in its initial list of HAPs published in 1990. 42 U.S.C. § 7412(b)(1).

The applicant's calculation of the estimated HAP emissions is faulty for at least three reasons. First, the applicant arbitrarily relied on a non-EPA emission factor to achieve more favorable numbers in its calculation of potential formaldehyde emissions. For 39 of the 40 HAPs that it has a potential to emit, the applicant calculated potential emissions using EPA-established emission factors set out in its AP-42 emission factor guidance document. JCEP Permit Application, Table B-12. For one of the HAPs, formaldehyde, the applicant used the emission factor used by the California Air Resource Board (CARB) in the natural gas firing combustion turbine phase. CARB's emission factor (1.10E-04) for formaldehyde is less than EPA's emission factor (7.10E-4) by a factor of seven. *See* Exhibit 4 at 41 (U.S. EPA AP-42 Emission Factor Guidance Document, Section 3.1 (Stationary Gas Turbines), Table 3.1-3). Using EPA's emission factor would substantially alter the facility's projections for emissions of formaldehyde. To support this single variance in its assumptions, the application states that EPA's emission factor for formaldehyde "is based on old testing data with limited data points that are not representative of the proposed units."

However, EPA's AP-42 document also contains ratings for each of its emission factors. Formaldehyde earned an "A" rating in the guidance document. An "A" rating signifies an "excellent" and that the method is representative of facilities in the source category. EPA describes A-rated emission factors as: developed primarily from A and B rated source test data taken from mainly randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability. *See* Exhibit 4 at 26 (EPA, Technology Transfer Network Clearinghouse for Inventories & Emissions Factors*, AP 42 Frequent Questions*). EPA's emission factor for formaldehyde is based on current projections and sound science. Further, the applicant uses EPA emission factors for other HAPs (including 1,3-Butadiene, Propylene Oxide, Acetaldehyde, Toluene, among others) that earned ratings of "C" ("Average") or "D" ("Below Average"). The discrepancy in selecting which emission factor to employ appears to be arbitrary, based simply on achieving a more favorable emission calculation.

Formaldehyde is the "most significant HAP" emitted from natural gas turbines and generally constitutes two-thirds of the total HAP emissions at such a facility. *See* Exhibit 4 at 33. The formaldehyde emissions constitute 19% of total HAP emissions at this proposed terminal. Despite a carbon monoxide oxidation catalyst that will reduce formaldehyde emissions, the HAP's potential pollution capacity is not accurately reflected in the application document. DEQ must revise the applicant's HAP emission calculations using EPA's emission factor for formaldehyde.

Second, the applicant failed to consider hexane emissions that are likely to result from the natural gas firing of new combustion turbines. The applicant estimated the facility has the potential to emit 2.5 tpy of hexane. This calculation reflects hexane emissions from natural gas firing duct burners, gas firing thermal oxidizers, and gas firing flares. Notably, a projection of hexane emissions is missing from the calculation for natural gas firing of new combustion turbines. It is unclear why hexane emissions are expected from all other natural gas fired elements of the facility's process, but not from combustion of the six turbines. DEQ must revise the calculations for hexane emissions.

Finally, the application is missing information that is essential to its potential emissions calculations. The applicant omitted a reference to source data for the ultra-low sulfur distillate firing South Dunes Fire Pump and Liquefaction Area Fire Pump on Table B-12 of the application. Before moving forward, DEQ must require the applicant to identify the source of this emission factor data in its calculations. Based on the unsupported assumptions and CARB substitutions identified above, the facility does not qualify as a major source of HAPs. DEQ must require the applicant to explain its assumptions that form the basis for the determination that the facility will not be a major source of HAPs.

4. *DEQ may not accept the applicant's Class II and Class I area analysis because the reasoning is fundamentally flawed.*

For a Class II area analysis, an applicant may demonstrate compliance with standards and PSD increments based on a single source impact analysis, and avoid a full air quality analysis, if the modeled impacts from emissions "are less than the Class II Significant Air Quality Impact Levels [SILs] specified in OAR 340-200-0020, Table 1." OAR 340-225-0050(1). A copy of OAR 340-200-0020, Table 1, from the Oregon Secretary of State's website is attached as Exhibit 8 (available at http://arcweb.sos.state.or.us/pages/rules/oars_300/oar_340/_340_tables/340-200-0020_11-7.pdf, last accessed April 2, 2015). If modeled impacts from emissions are greater than the corresponding SILs, the applicant must perform a full air quality impact analysis that will address the NAAQS and PSD increments and includes competing source analysis. OAR 340-225-0050(2). Because the applicant compared its modeled emissions to incorrect SILs values, the Class II air quality analysis is flawed and DEQ may not blindly rely on it.

As seen by the sections highlighted in yellow in the table below, the applicant compared its estimated maximum modeled concentrations with incorrect SIL values. DEQ relied on these erroneous numbers in its review of the permit. *See* DEQ Review Report at 31. DEQ concluded that "the maximum concentrations are below the applicable SILs, except for the 24-hour and annual PM2.5, 24-hour PM10, and 1-hour SO2 and NO2." DEQ Review Report at 31.

Pollutant	**Period**	**Class II SILs per OAR 340-200-0020, Table 1** ($\mu g/m^3$)	**SILs listed in DEQ's Review Report at 31** ($\mu g/m^3$)	**Single source modeled concentrations**
CO	1-hour	2,000	2,000	890.3
	8-hour	500	500	73.1
SO2	1-hour	8.0	7.8	**23.8**
	3-hour	25	25	13.1
	24-hour	5	5	2.5
	Annual	1.0	1	0.22
PM2.5	24-hour	1.2	1.2	**7.0**
	Annual	0.3	0.3	**0.71**
PM10	24-hour	1.0	5	**9.3**
	Annual	0.2	1	**0.79**
NO2	1-hour	8.0	7.5	**175.7**
	Annual	1.0	1	0.82

Applying the proper Class II SIL values, the annual PM10 maximum modeled concentration is also above the applicable SIL (orange highlighting in the table above). The applicant then erroneously did not complete a full air quality analysis for annual PM10, which would have included an assessment of the source impact area (SIA) and competing source impacts (referred to by the applicant as a multiple source NAAQS modeling assessment) for this parameter. DEQ improperly relied on the applicant's flawed analysis, allowing the applicant to avoid a full air quality analysis for annual PM10.

For those pollutants that the applicant completed a full air quality analysis, this was likewise flawed. First and foremost, the applicant submitted various protocols to DEQ detailing its proposed air quality modeling procedures, but these documents were not subject to public notice and review before DEQ's approval. It appears DEQ did make some of the modeling procedures available to the public at all. The applicant submitted an Air Quality Modeling Protocol to DEQ on November 28, 2012. *See* JCEP PSD Application, Appendix E. DEQ approved that protocol, without notice to the public or providing a period of review, on January 23, 2013. The applicant also stated that a multi-source air quality modeling protocol would be submitted under separate cover for approval by DEQ, and would include applicable modeling methodology to be used in the NAAQS analysis along with appropriate offsite source emissions. *Id.* at 5-13. Commenters were unable to identify this multi-source air quality modeling protocol in the materials made available to the public by DEQ. Since this protocol would serve as the basis for the applicant's full air quality analysis, it is impossible for Commenters to provide meaningful comment without reviewing its content.

Based on the information that the applicant and DEQ did provide to the public, it appears that the applicant relied on representative monitoring station data for the background concentrations in its full air quality impacts analysis. As previously explained, DEQ improperly allowed the applicant to rely on data from monitoring stations across the state instead of requiring monitoring of actual ambient background air quality data.

For similar reasons, DEQ must not accept the applicant's faulty Class I area analysis and analysis of impacts on soil, vegetation, and visiblity. For a Class I area PSD analysis, an applicant may demonstrate compliance with PSD increments based on a single source impact analysis if the modeled impacts from emissions (1) "are demonstrated to be less than the Class I impact levels specified in OAR 340-200-0020, Table 1," OAR 340-225-0060(2)(a); or (2) "are demonstrated to be less than the Class II impact levels specified in OAR 340-200-0020, Table 1." OAR 340-225-0060(2)(c). If the modeled impacts from emissions are not less than the Class I impact levels, the applicant "must also show that the increased source impacts (above Baseline Concentration) plus Competing PSD Increment Consuming Source Impacts are less than the PSD increments for all averaging times." OAR 340-225-0060(2)(b). Finally, an applicant may rely on a single source analysis to show compliance with PSD increments if the modeled impacts from emissions

As previously explained, the applicant used incorrect Class II SILs values to conclude that only the 24-hour and annual PM2.5, 24-hour PM10, and 1-hour SO2 and NO2 maximum concentrations exceeded the applicable SILs. Because the annual PM10 maximum modeled concentrations also exceeded the applicable Class II SIL, the applicant may not rely on a single source analysis to show compliance with PSD increments for the Class I analysis.

Pollutant	**Period**	**Class I SILs per OAR 340-200-0020, Table 1** (μg/m^3)	**SILs listed in DEQ's Review Report at 34** (μg/m^3)	**Single source modeled concentrations**
CO	1-hour	---	---	**---**
	8-hour	---	---	**---**
SO2	1-hour	---	---	**---**
	3-hour	1.0	1.0	**1.1**
	24-hour	0.20	na	0.2
	Annual	0.10	na	0.01
PM2.5	24-hour	0.07	0.07	**0.9**
	Annual	0.06	0.06	0.04
PM10	24-hour	0.30	0.3	**0.9**
	Annual	0.20	na	0.04
NO2	1-hour	---	---	**---**
	Annual	0.10	0.1	0.03

Here, too, the applicant compared its estimated maximum modeled concentrations with incorrect Class I SIL values (sections highlighted in yellow in the table above). DEQ relied on these erroneous numbers in its review of the permit. *See* DEQ Review Report at 34.

Although the modeling showed that emissions from the terminal would exceed Class I SILs for 3-hour SO2, 24-hour PM2.5, and 24-hour PM10 at Redwood National Park and the Kalmiopsis Wilderness Area (bolded in table above), DEQ did not identify this as an exceedance of the SILs. Instead, DEQ discounted the exceedances, claiming that "elevated terrain lying between the JCEP location and these Class I areas obstructs and diffuses plumes from JCEP before reaching the lower Class I elevations" and therefore "concentrations resulting from diffuse JCEP plumes are considered to be less than the SILs." DEQ Review Report at 35. It is unreasonable and arbitrary for DEQ to claim that numeric values in the model demonstrating an exceedance of the Class I SILs are "considered to be less than the SILs" without any additional justification. This is the modeling required to demonstrate impacts on Class I areas. If the modeling methodology was inappropriate, DEQ should have refined the modeling. But DEQ may not ignore these Class I SILs exceedances by claiming they are not exceedances. This analysis lacks any basis.

In addition to the Class II and Class I air quality impact analyses, an applicant for a PSD permit must analyze the impairment to visibility, soils, and vegetation that would occur as a result of the source and other growth associated with the source or modification. 40 C.F.R. § 52.21(o). As for vegetation, the applicant relied solely on the EPA guidance document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals,* (U.S. EPA, 1980), which provided screening concentrations for CO, SO2, and NO2. The applicant improperly ignored impacts of CO2 and other GHG emissions on foliage (see discussion in part I, above, regarding CO2 impacts on vegetation).

In its analysis of the facility's impacts on visibility, it is unclear whether the applicant considered the particular geographic conditions of a coastal region and how that would impact the modeling used. DEQ should reconsider the applicant's conclusion that the terminal will not impact visibility in the area surrounding the proposed facility site. In fact, this facility proposed to emit significant NOx and VOC emissions, which are precursors to ozone.

Although not Class I designated areas, the following wilderness areas are in close proximity to the proposed terminal and have significant natural resources that will be impacted by the terminal's emissions: Drift Creek Wilderness, Cummins Creek Wilderness, Rock Creek Wilderness, Diamond Peak Wilderness, Glide Boulder Creek Wilderness, Mt. Thiesen Wilderness, Rogue-Umpqua Divide Wilderness, Sky Lake Wilderness, Wild Rogue Wilderness, Grassy Knob Wilderness, Mountain Lakes Wilderness, or Red Buttes Wilderness. Neither the applicant nor DEQ discussed air quality impacts to these special natural resources. DEQ must require the applicant to complete a more thorough analysis of impacts on vegetation and visibility that complies with the federal minimum requirements.

The applicant proposes to emit enormous amounts of heat directly into the air during cooling processes at the liquefaction facility. Neither the applicant nor DEQ considered whether the coastal range location of the facility (and the existence of a marine layer) combined with these emissions could create a fog bank when temperatures drop due to the proposed LNG facility being in close proximity to the Coos Bay waterbody. It does not appear that the applicant consider such factors in its modeling. DEQ should require modeling that more accurately reflects the factors present at the terminal's proposed site.

Finally, DEQ must not accept the applicant's extremely cursory analysis the air quality impact that will result from the growth associated with the terminal. 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. 40 C.F.R. § 52.21(o). The applicant has repeatedly touted the economic growth that will be associated with the terminal, but at the same time attempts to ignore the adverse impact on air quality that this additional growth will cause. The applicant claimed that "air emissions from the proposed Facility will not result in excessive PSD increment consumption" and therefore "increment is available for new industry" that may be associated with the terminal. This statement is wholly unsupported by the applicant's own emissions estimates and PSD increment analysis. DEQ must not accept the applicant's claim that there will be no air quality impacts from associated growth.

Conclusion

Given the adverse impacts to air quality likely to result from this terminal, we urge DEQ to deny the requested air permit. Short of a denial, DEQ must address the omissions and inconsistencies identified above, revise the permit accordingly, and issue a revised proposed permit for public notice and comment. Proper analysis and regulation of the facility's emissions that is consistent with the CAA and Oregon's own rules under its SIP is critical to protecting Oregon's air quality.

Sincerely,

Marla Nelson
Staff Attorney, NEDC

Ben Muzi
Student Volunteer, NEDC

On behalf of:

Beyond Toxics
Cape Arago Audubon Society
Cascadia Wildlands
Citizens Against LNG
Clam Diggers Association of Oregon
Friends of Living Oregon Waters
Neighbors for Clean Air
Northwest Environmental Advocates
Northwest Environmental Defense Center
Oregon Coast Alliance
Oregon Shores Conservation Coalition
Oregon Wild
Rogue Climate
Rogue Riverkeeper
Sierra Club
South Umpqua Rural Community Partnership
Umpqua Watersheds, Inc.
Waterkeeper Alliance
Western Environmental Law Center

Exhibit List

1	EPA, Human Health & Environmental Effects of Emissions from Power Generation
2	IPCC, Summary for Policymakers 2014
2a	Pub. Utility Commission of Oregon, SB 101 Progress Toward and Rate Impact of State GHG Emission Goals 2014
3	DEQ, Memorandum from Dick Pedersen to Environmental Quality Commission
4	Comment Letter April 15, 2014 • Page 9 – EPA, Global Warming Potentials of ODS Substitutes • Page 13 – ExxonMobile Upstream Research Co., LNG Liquefaction Process Selection: Alternative Refrigerants to Reduce Footprint and Cost • Page 26 – EPA, AP 42 Frequent Questions • Page 29 – EPA, Stationary Gas Turbines • Page 298 – EPA, PSD and Title V Permitting for Greenhouse Gases • Page 403 – EPA Region VI Letter from John Calcagni to Waid and

	Associates • Page 405 – EPA Region VI Letter from Charles Sheehan to Michael Cathey and Diana Dutton
5	Coos County, Notice of Withdrawal of Administrative Application & Subsequent Appeals
6	EPA, Statement of Basis: Draft GHG PSD Preconstruction Permit for the Freeport LNG Development, LP, Freeport LNG Liquefaction Plant
7	IPCC, Special Report on Carbon Dioxide Capture and Storage 2005
8	OAR 340-200-0020, Tables 1, 2, 3, 4 & 5
9	EPA, Ambient Monitoring for PSD 1987
10	Google Earth map of monitoring data locations
11	EPA, Designation of North American Emission Control Area to Reduce Emissions from Ships
12	Dan Healing, Calgary Herald, Pipeline stake expected to fuel Veresen LNG project
13	Dan Healing, Calgary Herald, Court rules investor can buy into Jordan Cove LNG
14	EPA, Substitute Refrigerants Under SNAP
15	DEQ, Fact Sheet: Jordan Cove Energy Project