October 14, 2019
Re: JCEP Omnibus II Permit Application HBCU-19-003

North/West side of Conde B. McCullough Memorial Bridge, North Bend, Oregon - Jan 11, 2019 - Photo Jody McCaffree

To preserve, protect ... and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations. CZMA- § 1452 (Section 303) (1)

Submitted by:

Jody McCaffree
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Andrew Stamp, Hearings Officer
Coos County Planning Department
225 N. Adams St.
Coquille OR 97423

RE: Comments under Coos County File No. HBCU-19-003

Dear Hearing Officer Stamp:

Please accept these comments into the record on behalf of Citizens for Renewables and Jody McCaffree an Individual.   This Application proposes the following new developments and activities:

- A meteorological station in the 4-CS zone;
- An industrial wastewater pipeline in the IND zone;
- A concrete batch plant in the IND zone;
- A safety, security, and emergency preparedness, management and response center in the IND zone;
- A helipad in the IND zone;
- Corporate and administrative offices in the IND zone;
- Temporary workforce housing in the IND zone;
- A wastewater treatment facility in the IND zone;
- A park and ride in the IND zone;
- Temporary construction laydown uses and activities in the IND, 6-WD, 3-WD, and 3-NWD zones;
- A temporary barge berth in the 6-DA zone;
- Shoreline stabilization within the 5-WD zone;
- Pile dike rock apron in the 5-DA zone;
- Provision of primary access to the LNG Terminal in the 6-WD zone (driveway confirmation);
- Temporary dredge transport lines in the 6-DA, 7-NA, 13B-NA, and 14-DA zones;
- Gas processing in the 6-WD zone; and
- A fire station in the 6-WD zone.

The application should have been deemed incomplete due to lack of data and information that has been provided with respect to the project. For example, not one place in the application are there details concerning how many workers would be living at Jordan Cove's proposed workforce housing mancamps nor are the diagrams that Jordan Cove provided sufficient to determine if the workforce housing meets the Coos County Zoning and Land Development Ordinance (CCZLDO) requirements. Jordan Cove has not provided a geological assessment as required under CCZLDO 5.11 or any details as to how much fill would be placed on the South Dunes Power Plant property or on the 6 WD property. Where are the detailed elevation profiles and a plot plan, both drawn to scale, including the location and height of all existing and proposed structures as required under CCZLDO 4.11.440? Jordan Cove has not provided the necessary resource impact assessments as required by the Coos Bay Estuary Management Plan (CBEMP) Policies 5, 5a and 4. Due to the fact the applicant does not have an approved land use permit for their proposed Transpacific Parkway widening project and due to their complete change in traffic patterns, a new traffic impact statement should be required that includes impacts on the Dunes National Recreation Area and the Coos Estuary. In addition, the following travel impacts noted below were not included in Jordan Cove's previous transportation analysis and need to be included in an updated traffic analysis. In a filing that Jordan Cove submitted to FERC on May 1, 2015 under the prior FERC proceeding they stated the following:[1]

> *The following table is a breakdown of material and equipment shipments coming to the project site by transportation mode. All quantities are a conservative estimate in order to cover transportation unknowns as the transport mode of some equipment is still undecided. The numbers of shipments are estimated by the year and quarter those shipments are likely to be needed at the project site.*

		Break Bulk Ship	Barge	Road	Rail
2016	Q2	-	-	100	-
	Q3	-	-	500	-
	Q4	-	-	1,000	13
2017	Q1	-	-	2,200	12
	Q2	-	-	1,900	-
	Q3	-	-	3,400	-
	Q4	-	-	5,400	-
2018	Q1	-	-	9,300	-
	Q2	1	2	11,600	-
	Q3	6	2	20,000	-
	Q4	14	2	27,000	-
2019	Q1	25	4	29,000	-
	Q2	23	4	32,600	-
	Q3	9	2	34,000	-
	Q4	4	2	33,000	-
2020	Q1	-	-	30,000	-
	Q2	-	-	22,000	-
	Q3	-	-	18,000	-
	Q4	-	-	15,600	-
2021	Q1	-	-	12,600	-
	Q2	-	-	11,000	-

All impacts, including cumulative impacts need to be considered. This HBCU-19-003 Jordan Cove Energy Project (JCEP) application is totally dependent on the approval of JCEP's Remand application filed under Coos County File No REM-19-001for the proposed JCEP's prior LNG terminal design. **REM-19-001 has yet to be resolved along with many other Jordan Cove land use applications that are currently before the County and the Cities of North Bend and Coos Bay.**

According to the November 27, 2017 LUBA 2016-095 (*Oregon Shores v Coos County*) Decision pages 9 and 10: (***See Exhibit 20***)

> *…While the text of CBEMP Policy 5(I)(b) and Goal 16 IR2 is not entirely clear on this point,* ***<u>the context indicates that the four standards do not apply only to the proposed dredging or</u>***

[1] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20150501-5458

fill. *We note that* ***Goal 16 IR2(c) requires a finding that "no feasible alternative upland locations exist,"*** *which clearly contemplates evaluation of the proposed land use, not proposed dredging, since dredging does not generally take place on upland locations. We conclude that, contrary to the county's finding,* ***CBEMP Policy 5(I)(b) requires the county to evaluate the substantiality of the public benefits provided by the use that the proposed dredging serves****, in this case the LNG terminal, or at least those components of the terminal that are properly viewed as water-dependent uses.*
(Emphasis added)

LUBA 2016-095 (*Oregon Shores v Coos County*) Decision page 12 and 13 state: (***See Exhibit 20***)

…We agree with Oregon Shores. CBEMP Policy 5(I)(a) and Goal 16 IR2(a) in relevant part require that the proposed dredging serve a water-dependent use allowed under the county's code. The county's view that the "need/substantial public benefit" standard in CBEMP Policy S(I)(b) and Goal 16 IR2(b) is met simply by the fact that the proposed dredging serves a use allowed under the county's code, conflates CBEMP Policy 5(I)(a) and (b) and gives no independent effect to the latter. Even if the proposed dredging serves a water-dependent use allowed under the county's code, ***the county can allow the dredging only if it also finds that the use provides a substantial public benefit****.*

The proposed Barge Berth, Pile Rock Apron, Marine Slip Dock and Navigation Channel Alterations being proposed by JCEP have not met the requirements of the Coos Bay Estuary Management Plan (CBEMP) Policy 5.

#5 Estuarine Fill and Removal

I. Local government shall support ***dredge and/or fill*** ***only if such activities are allowed in the respective management unit, and****:*

a. The activity is required for navigation or other water-dependent use that require an estuarine location or in the case of fills for non-water-dependent uses, ***is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation****, as per ORS 541.625(4) and an exception has been taken in this Plan to allow such fill;*
b. ***A need (ie., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights****;*
c. No feasible alternative upland locations exist; and
d. ***Adverse impacts are minimized.***
e. Effects may be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained;
f. The activity is consistent with the objectives of the Estuarine Resources Goal and with other requirements of state and federal law, specifically the conditions in ORS 541.615 and Section 404 of the Federal Water Pollution Control Act (P.L.92-500).
(Emphasis added)

II. Other uses and activities which could alter the estuary shall only be allowed if the requirements in (b), (c), and (d) are met.

Identification and minimization of adverse impacts as required in "d" above shall follow the procedure set forth in Policy #4. (Emphasis added)

* * * *

...Identification and minimization of adverse impacts as required in "e" above shall follow the procedure set forth in Policy #4a. The findings shall be developed in response to a "request for comment" by the Division of State Lands (DSL), which shall seek local government's determination regarding the appropriateness of a permit to allow the proposed action.

"Significant" as used in "other significant reduction or degradation of natural estuarine values", shall be determined by: a) ***the U.S. Army Corps of Engineers through its Section 10.404 permit processes****; or b) the Department of Environmental Quality (DEQ) for approvals of new aquatic log storage areas only; or c) the Department of Fish and Wildlife (ODFW) for new aquaculture proposals only.* (Emphasis added)

This strategy recognizes that Goal #16 limits dredging, fill and other estuarine degradation in order to protect the integrity of the estuary. (Emphasis added)

A need (ie., a substantial public benefit) has not been demonstrated by the applicant. The project would unreasonably interfere with navigation, fishing and public recreation and would therefore not be in compliance with CBEMP Policy 5(I)(b). Components of the terminal and LNG tanker ships would conflict with the navigable airspace of the Southwest Oregon Regional Airport among many other public benefit and use impacts.

There is no American public benefit to the loss of fish, marine and wildlife habitat due to the destructive nature of all the proposed dredging for the Jordan Cove / Pacific Connector Project. The Pacific Connector Pipeline construction is projected to impact 485 wetlands and waterbodies in Southern Oregon, many of which are salmon bearing.

The Coos Bay Estuary is already 303D limited and this project will only make that situation worse. Jordan Cove's sedimentation expert expects us to believe that there would be no negative impacts with sedimentation or turbidity from all their proposed dredging. Our sedimentation expert actually proved Jordan Cove's data to be incorrect on this issue during the land use process under Coos County File No. REM 10-01 for HBCU-10-01. (***See Exhibit 29****)*

The proposed Barge Berth, Pile Rock Apron, Marine Slip Dock and Navigation Channel Alterations have not met the requirements of the Coos County Zoning and Land Development Ordinance (CCZLDO):

SECTION 5.0.150 APPLICATION REQUIREMENTS:

Applications for development or land use action shall be filed on forms prescribed by the County and shall include sufficient information and evidence necessary to demonstrate compliance with the applicable criteria and standards of this Ordinance and be accompanied by the appropriate fee. An application shall not be considered to have been filed until all application fees have been paid. All applications shall include the following:

1. ***Applications shall be submitted by the property owner or a purchaser under a recorded land sale contract. —Property owner" means the owner of record, including a contract purchaser. The application shall include the signature of all***

owners of the property. A legal representative may sign on behalf of an owner upon providing evidence of formal legal authority to sign. *(Emphasis added)*

* * * *

An application may be deemed incomplete for failure to comply with this section. ***The burden of proof in showing that an application complies with all applicable criteria and standards lies with the applicant***.

SECTION 5.0.175 APPLICATION MADE BY TRANSPORTATION AGENCIES, UTILITIES OR ENTITIES:

1. A transportation agency, ***utility company or entity with the private right of property acquisition pursuant to ORS Chapter 35*** *may submit an application to the Planning Department for a permit or zoning authorization required for a project without landowner consent otherwise required by this ordinance. (Emphasis added)*

* * * *

It should be noted that Jordan Cove is taking out land use permits for the Estuary when they are not the legal owner of the Coos Estuary nor do they have **the private right of property acquisition pursuant to ORS Chapter 35.**

The person who signed the application that was filed with Coos County was **Natalie Eades.** She has signed other documents as senior council for Jordan Cove/Pacific Connector, Pembina Pipeline Corporation. (***See Exhibit 23***) She essentially works for **Pembina, a Canadian Energy Company, via JCEP.** She is signing statements with respect to the Coos Estuary that say**: *"I am the legal owner of record or an agent having consent of the legal owner of record and am authorized to obtain this zoning compliance letter so as to obtain necessary permits for development from the Department of Environmental Quality and/or the building codes agency."***

On July 6, 1967, the Oregon Beach Bill[2] was passed by the legislature and signed by Oregon Governor Tom McCall. The Beach Bill declares that all "wet sand" within sixteen vertical feet of the low tide line **belongs to the State of Oregon**. The Beach Bill recognizes public easements of all beach and tidal areas up to the line of vegetation, regardless of underlying property rights. The public has free and uninterrupted use of these areas and property owners are required to seek **state permits** for building and other uses. While some parts of the beach and tidal areas remain privately owned, state and federal courts have upheld Oregon's right to **regulate development** of those lands and preserve public access.[3]

2017 ORS 537.110[4]

All water within the state from all sources of water supply ***belongs to the public***.
(Emphasis added)

Citizens who actually live in Coos County have been trying for some 12 years now to get the natural hazard maps added to the Estuary and Coastal Shoreland zoning districts in Coos County and THAT STILL HAS NOT OCCURRED. And yet, when Jordan Cove wants to make changes to the Estuary zoning districts these applications are processed right away? **There needs to be some kind of**

[2] House Bill 1601, 1967
[3] https://en.wikipedia.org/wiki/Oregon_Beach_Bill
[4] https://www.oregonlaws.org/ors/537.110

investigation into these matters. The natural hazard maps need to be added to the Coos Estuary and Shoreland zoning districts and Statewide Planning Goal #7, which prohibits the siting of hazardous facilities in identified natural hazard areas, **needs to be enforced by Coos County and the State of Oregon**.

In the matter of Jordan Cove, condemnation authority comes from the Federal Energy Regulatory Commission‘s (FERC) approval of a ―Certificate of Public Convenience and Necessity" under the Natural Gas Act and FERC has not issued Pembina‘s Jordan Cove a Certificate yet. The ―private‘ Jordan Cove/Pacific Connector Project DOES NOT HAVE THE RIGHT OF EMINENT DOMAIN.

2017 ORS 196.810 states:

> **Permit required to remove material from bed or banks of waters**
>
> *(1)(a) Except as otherwise specifically permitted under ORS 196.600 (Definitions for ORS 196.600 to 196.655) to 196.905 (Applicability),* ***a person may not remove any material from the beds or banks of any waters of this state or fill any waters of this state without a permit issued under authority of the Director of the Department of State Lands****, or in a manner contrary to the conditions set out in the permit,* ***or in a manner contrary to the conditions set out in an order approving a wetland conservation plan****.* (Emphasis added)
>
> * * * *

In addition. the Oregon Department of State Lands also must sign off on any removal of dredged material from the Coos Estuary as explained below.

ORS § 196.805 Policy

> *(1)****The protection, conservation and best use of the water resources of this state are matters of the utmost public concern****. Streams, lakes, bays, estuaries and other bodies of water in this state, including not only water and materials for domestic, agricultural and industrial use but also habitats and spawning areas for fish, avenues for transportation and sites for commerce and public recreation, are vital to the economy and well-being of this state and its people.* ***Unregulated removal of material from the beds and banks of the waters of this state may create hazards to the health, safety and welfare of the people of this state. Unregulated filling in the waters of this state for any purpose, may result in interfering with or injuring public navigation, fishery and recreational uses of the waters****. In order to provide for the best possible use of the water resources of this state, it is desirable to centralize authority in the Director of the Department of State Lands, and implement control of the removal of material from the beds and banks or filling of the waters of this state.* (Emphasis added)

ORS 196.825 Criteria for issuance of permit:

> *(1) The Director of the Department of State Lands shall issue a permit applied for under ORS 196.815 if the director determines that the project described in the application:*
>
> *(a)* ***Is consistent with the protection, conservation and best use of the water resources of this state*** *as specified in ORS 196.600 to 196.905; and*
>
> *(b)* ***Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation.***
>
> *(2) If the director issues a permit applied for under ORS 196.815 to a person that proposes a removal or fill activity for construction or maintenance of a linear facility, and if that person is not a landowner or a person authorized by a landowner to conduct the proposed removal or fill*

activity on a property, then the person may not conduct removal or fill activity on that property until the person obtains:

(a) The landowner's consent;

(b) A right, title or interest with respect to the property that is sufficient to undertake the removal or fill activity; or

(c) A court order or judgment authorizing the use of the property.

(3) In determining whether to issue a permit, the director shall consider all of the following:

(a) ***<u>The public need for the proposed fill or removal</u>*** *and the social, economic or other public benefits likely to result from the proposed fill or removal. When the applicant for a permit is a public body, the director may accept and rely upon the public body's findings as to local public need and local public benefit.*

(b) The economic cost to the public if the proposed fill or removal is not accomplished.

(c) ***<u>The availability of alternatives to the project for which the fill or removal is proposed</u>****.*

(d) The availability of alternative sites for the proposed fill or removal.

(e) ***<u>Whether the proposed fill or removal conforms to sound policies of conservation and would not interfere with public health and safety</u>.***

(f) ***<u>Whether the proposed fill or removal is in conformance with existing public uses of the waters and with uses designated for adjacent land in an acknowledged comprehensive plan and land use regulations</u>.***

(g) ***<u>Whether the proposed fill or removal is compatible with the acknowledged comprehensive plan and land use regulations for the area where the proposed fill or removal is to take place or can be conditioned on a future local approval to meet this criterion</u>.***

(h) ***Whether the proposed fill or removal is for streambank protection.***

(i) ***<u>Whether the applicant has provided all practicable mitigation to reduce the adverse effects of the proposed fill or removal</u>*** *in the manner set forth in ORS 196.800. In determining whether the applicant has provided all practicable mitigation, the director shall consider the findings regarding wetlands set forth in ORS 196.668 and whether the proposed mitigation advances the policy objectives for the protection of wetlands set forth in ORS 196.672.*

(4) The director may issue a permit for a project that results in a substantial fill in an estuary for a nonwater dependent use ***<u>only if the project is for a public use and would satisfy a public need that outweighs harm to navigation, fishery and recreation and if the proposed fill meets all other criteria</u>*** *contained in ORS 196.600 to 196.905.*
(Emphasis added)
Land Use not Compatable with Surrounding Uses

BARGE BERTH in 6-WD ZONE

According to Jordan Cove's application Narrative (Page 18), (Electronic page 41 of submittal), JCEP states:

> *The temporary barge berth will be sized to accommodate ocean going barges ranging in length from 100 to 250 feet long, and 45 to 55 feet wide with a loaded draft of 10'. The barges will be berthed with one end pushed approximately 60 feet into the excavated slot and tied off to piling driven into the berm around the berth opening.*

ZONING DISTRICT: 6-WATER-DEPENDENT DEVELOPMENT SHORELANDS

SECTION 3.2.275. MANAGEMENT OBJECTIVE: This district shall be managed so as to protect the shoreline for water-dependent uses in support of the water-related and non-dependent, non-related industrial use of the area further inland….

A. Uses:

6. Industrial & Port facilities… ACU-S,G [Admin Cond Use allowed subject to Special and General Conditions.]
9. Marinas …N [Not Allowed]
17. Water-borne transportation ACU-S,G [Allowed subject to Special and General Conditions

B. Activities:
3. Dredged Material disposal ACU-S, G
4. Excavation to create new water surface P-G
5. Fill P-G

GENERAL CONDITIONS (the following condition applies to all uses and activities):
*1. **<u>Inventoried resources requiring mandatory protection in this district are subject to Policies#17 and #18</u>**.*
*2. **<u>All permitted uses and activities shall be consistent with Policy #23 requiring protection of riparian vegetation</u>**.*
*3. Uses in this district are **<u>only permitted as stated in Policy #14 "General Policy on Uses within Rural Coastal Shoreland</u>**s". Except as permitted outright, or where findings are made in this Plan, uses are only allowed subject to the findings in this policy.*
*4. **<u>All permitted uses shall be consistent with the respective flood regulations of local governments, as required in Policy #27</u>**.*
5. All permitted uses in dune areas shall be consistent with the requirements of Policy #30
6. In rural areas (outside of UGBs) utilities, public facilities and services shall only be provided subject to Policies #49, #50, and #51. SPECIAL CONDITIONS

SPECIAL CONDITIONS
Uses:
4. Commercial uses shall be allowed only if they are support services to existing or planned industrial uses and will not preclude water-dependent use of the shoreline.

4.,6.,16.,17. These uses are subject to review and approval when consistent with Policy #16.
*   *   *   `*

Activities:
1. Alteration of waterways may be necessary in association with the development of a new Port road, and shall be allowed, provided that the relocation of culverts and similar alterations are done in a manner so as to not alter the hydrologic characteristics of existing wetlands.
3. Dredge material disposal shall be allowed when consistent with Policy #20.
*   *   *   *

Jordan Cove has not met CBEMP Policy 5 requirements for removal/fill nor have they met the management objectives of the 6WD zoning district. See more information on this further below.

PILE DIKE ROCK APRON IN THE 5-DA ZONE

ZONING DESIGNATION: 5-DA - SECTION 3.2.270 and 3.2.271
A. Uses:
* * * *
4. Industrial & Port facilities ACU-S
* * * *
B. Activities:
* * * *
1. Dikes
    a. New construction N/A
    b. Maintenance/repair N/A
2. Dredging
    a. New ACU-S
    b. Maintenance dredging of existing facilities ACU-S
    c. To repair dikes and tidegates N/A
3. Dredged Material disposal N [Not Allowed]
4. Fill ACU-S
5. Navigation Structures ACU-S
* * * *

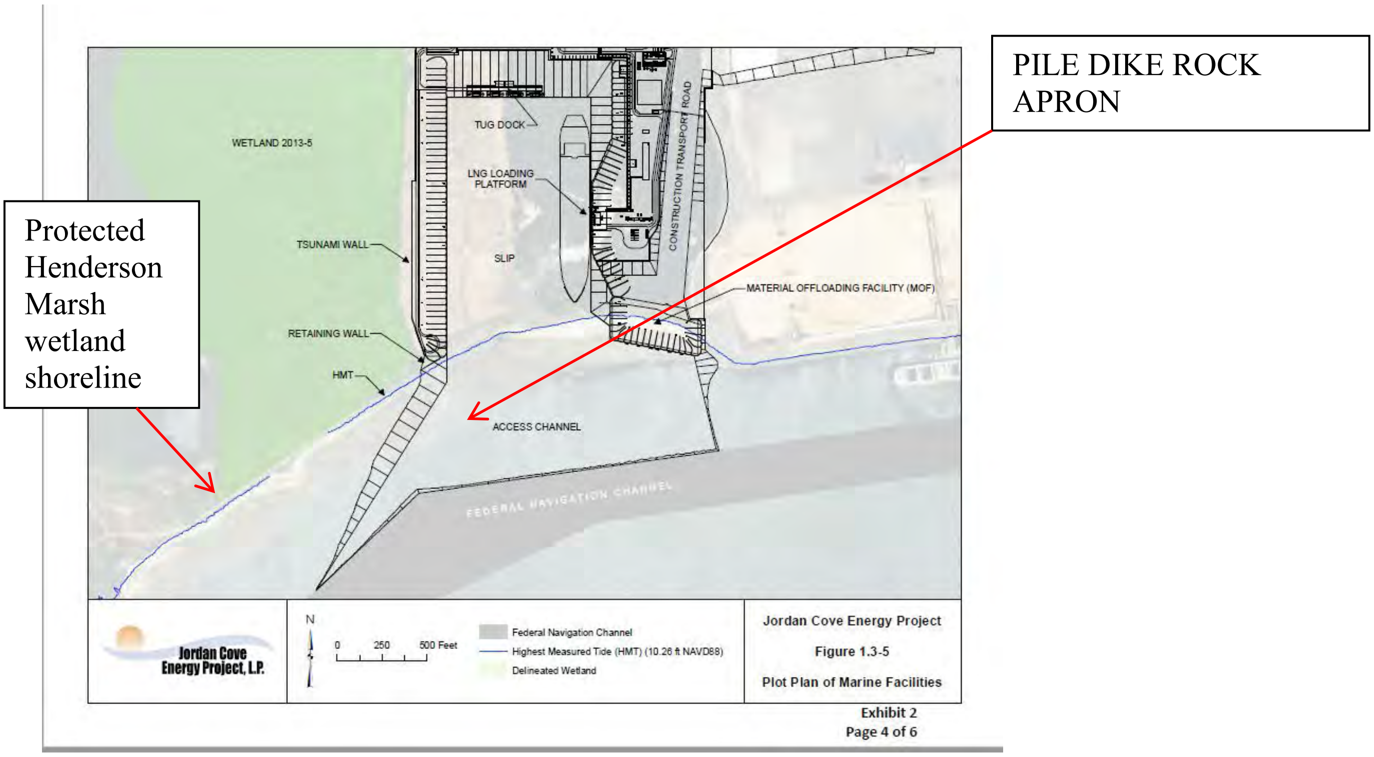
SPECIAL CONDITIONS
Uses:
* * * *

4. Water-dependent uses are allowed. If the use is water-related or non-dependent/related and does not require fill, findings must be made that the use is consistent with the resource capabilities and purposes of the management unit. **Fill is not permitted for nonwater-dependent uses**.
* * * *

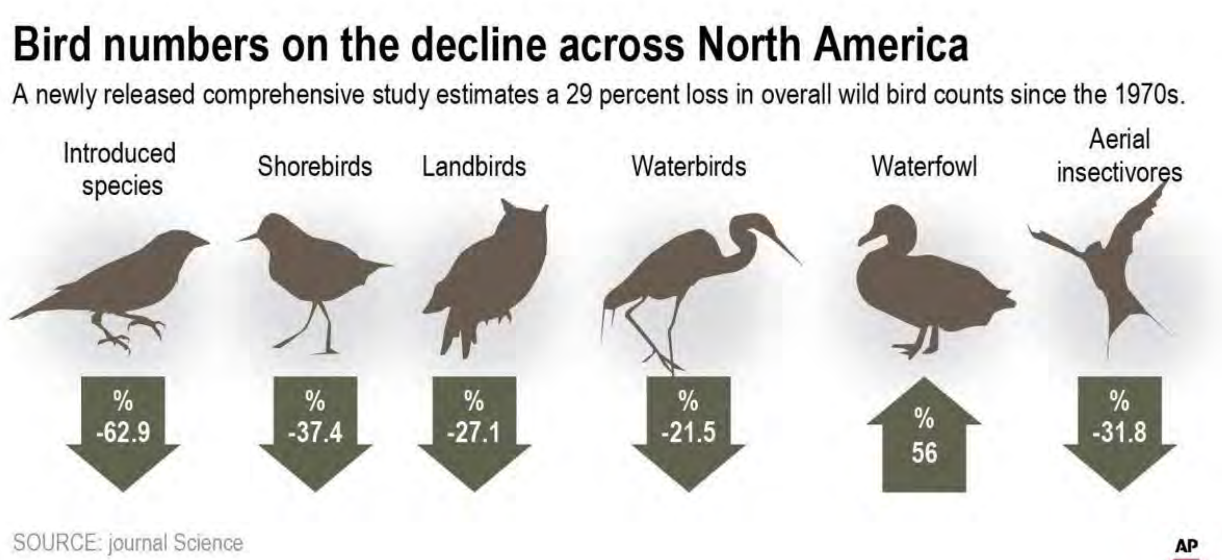
Activities:

4. **Fills shall be allowed when findings are made which document that the fill will not adversely impact the wetland drainage in the southwest shoreline portion of the district. In addition, this activity is only allowed subject to finding that adverse impacts have been minimized (see Policy #5); and to Policy #8 requiring mitigation**.

2a., 2b., 5. These activities are only allowed subject to finding that adverse impacts have been minimized (see Policy #5); and to Policy #8 requiring mitigation
* * * *



The above is NOT shoreline stabilization as it is not anywhere near the actual shoreline area as the applicant has suggested. This is more on the order of their proposed marine slip dock stabilization. This will clearly affect the hydrology of Henderson marsh and significantly affect shorebird habitat. These tidal areas that would be taken out of production would be a significant loss to migratory shorebirds and other habitat. According to a new study birds have been disappearing at an alarming rate including shorebirds. Experts say **habitat loss was the No. 1 reason for bird loss**. (***See Exhibit 69***)



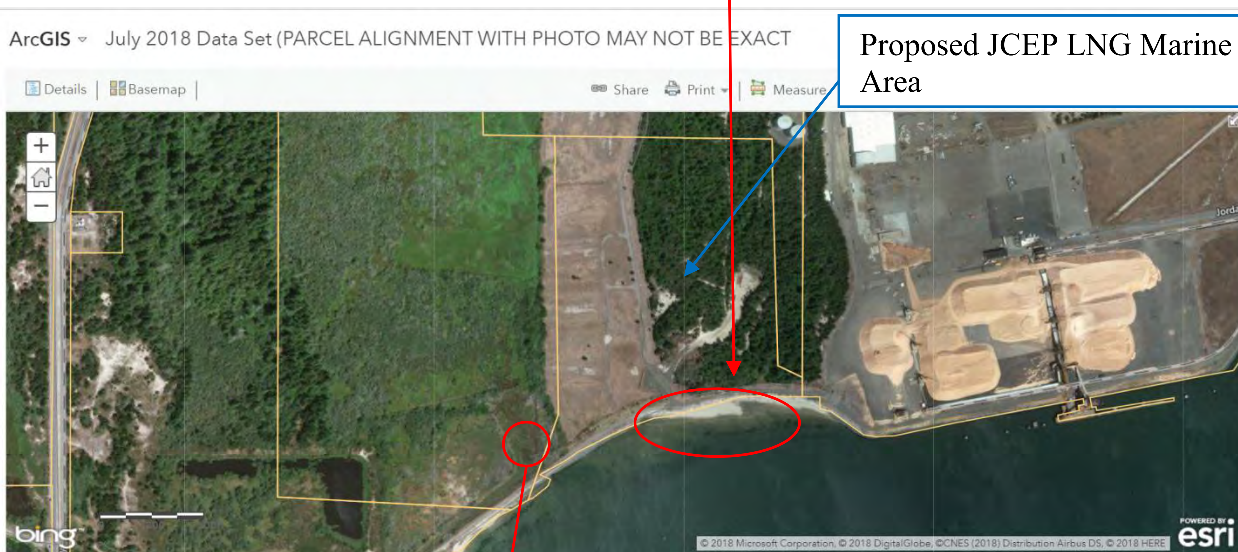
There is a growing need to restore these bird habitat areas NOT destroy more of them. Below find current evidence of clams and sand shrimp that **<u>are not being properly mitigated</u>** in the area of Jordan Cove's proposed marine terminal:

Evidence of clams, thousands of sand shrimp and eelgrass can be found in the vicinity of the proposed LNG marine terminal, barge berth and pile dike rock apron but much of this habitat is not on any habitat maps and is not being protected or mitigated properly by Jordan Cove.

Above a clam digger digs for clams - May 2018
Below Plovers get a meal at low tide in the tidal areas of the proposed LNG marine slip dock, barge berth and pile dike rock apron:.

Plovers & Geese take to flight in tidal areas where proposed LNG Marine Dock would be built - May 2018.

Proposed JCEP LNG Marine Slip Dock Area



Below Canadian Geese hang out in wetlands west of the proposed LNG slip dock - May of 2018.

The habitat area above would be <u>totally destroyed</u> by the removal of 5.7 million cubic yards in these tidal areas. One-third of Oregon wetlands are estimated to have been lost since the late 1700s. Wetlands are now protected under federal law, and loss of estuarine wetlands has slowed substantially since the mid-1900s (Oregon Division of State Lands and Oregon State Parks and Recreation Division 1989, Dahl 1990). Of the waterbodies that would be crossed by this project in the analysis area, 14 waterbodies in the BLM's Coos District, 5 waterbodies in the BLM's Medford District and 4 waterbodies in the Klamath Sub-basin are known to be 303d water quality limited. (2009 FEIS *Biological Evaluation* - Page 170 - H-331).

Coastal and inland mudflats are an important ecosystem for many shorebird types throughout our state and elsewhere. They rely on these mudflats particularly during migration as well as the late summer/fall/winter and possibly even early spring should shorebirds find a reliable food source to keep them viable until they again migrate to nest. The Sand Shrimp and other micro organisms that are part of mudflats are most likely important food sources for shorebirds.

Despite this Jordan Cove‘s September 2017 Resource Report #3 states on page 107: ―*Noise associated with construction and operation of the facility is the only direct effect to plovers*.” **I think the above pictures prove this not to be the case.**

The Canada Geese above are most likely permanent residents of the area and most Canada Geese can be seen year round (they are not long-range migrants, for the most part, like Greater White-fronted Geese and Snow Geese that breed in Alaska/Canada and then travel to areas such as Lower Klamath National Wildlife Refuge, Sacramento NWR, all the way to the southern interior of the U.S. during winter).

CCCZLDO SECTION 4.11.120 Goal #5 Conflict Resolution Process:

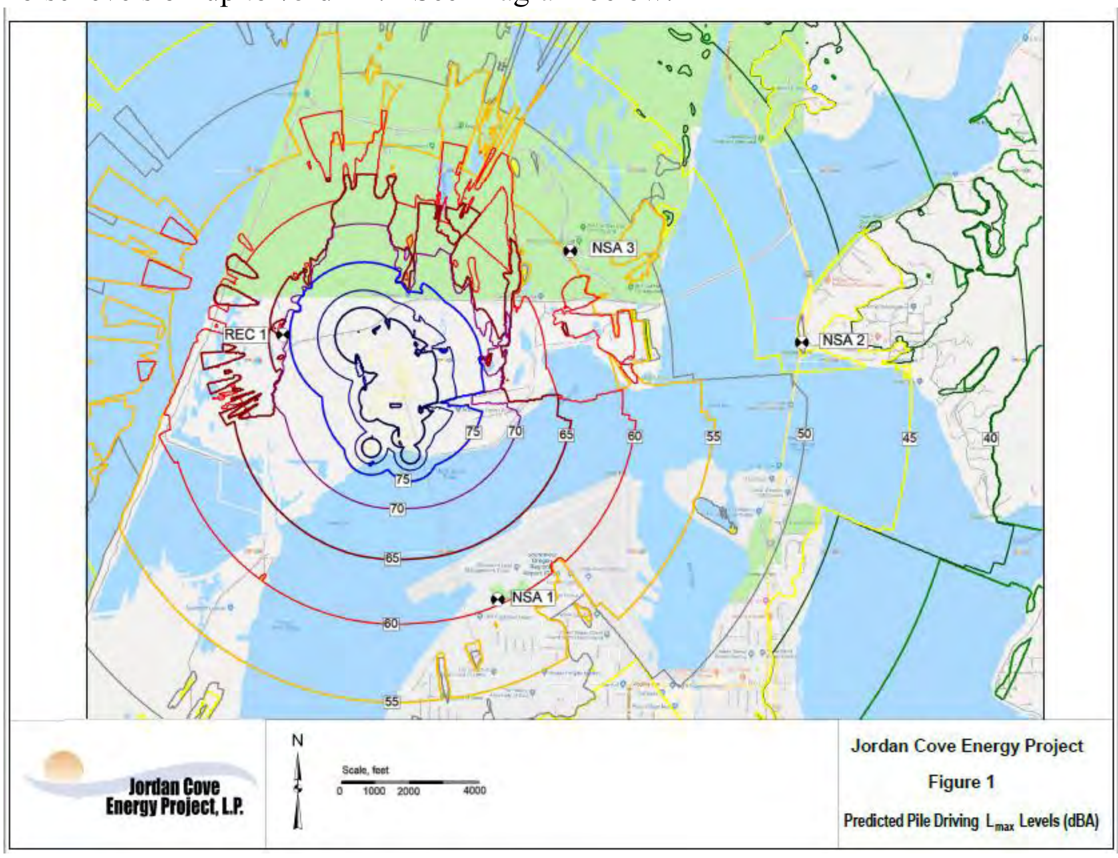
> *When in the course of implementing the Coos County Comprehensive Plan it becomes evident that a conflict exists concerning the use of land identified as a Oregon Statewide Planning Goal #5 resource that is otherwise protected pursuant to OAR 660-16-005(1), then any proposed conflicting use may only be allowed after the an Administrative Conditional Use application has been completed based on findings that address the requirements of OAR 660-16-0005(2) and OAR 660-165-0010. SECTION 4.11.125 Special Development Considerations*

CCZLDO SECTION 4.11.125 Special Development Considerations:

> *The considerations are map overlays that show areas of concern such as hazards or protected sites. Each development consideration may further restrict a use. Development considerations play a very important role in determining where development should be allowed In the Balance of County zoning. The adopted plan maps and overlay maps have to be examined in order to determine how the inventory applies to the specific site.*
>
> * * * *
>
> *6. Significant Wildlife Habitat (Balance of County Policy 5.6)*
>
> * * * *
>
> *The following bird habitat areas that are considered Goal #5 "5c" resources:*
>
> * * * *
>
> *Great Blue Heron Colonies are listed to be occurring at: 25S 11W 15 (Weyerhaeuser)*
>
> * * * *
>
> *b. 5b Bird Sites protection shall consider the following to be "5b" resources, pursuant to the inventory information available in this Plan and OAR 660-16-000(5)(b):*
>
> - *Osprey Nesting Sites*
> - *Snowy Plover Habitat (outside the CREMP)*
> - *Spotted Owl Nesting Sites*
>
> *This policy recognizes the requirements of OAR 660-16. Coos County's Planning Staff is unable to perform ground verification; therefore, the County relies on ODFW for the applicable information.*
>
> *Coos County shall require a location map for any development activity with the exception of grazing within its regulatory scope that is determined to be within a "5b" bird habitat. The location map shall be referred to the Oregon Department of Fish and Wildlife requesting an opinion as to whether the development is likely to produce significant and unacceptable impacts upon the "5b" resource. Oregon Department of Fish and Wildlife staff shall respond prior to any development.*

Noise is also an issue

Jordan Cove's September 17, 2019 filing with the FERC showed that their pile driving could create noise levels of up to 75 dBA.[5] See Diagram below:



A 2017 study published in the journal PLOS ONE found that even though oysters do not have ears they react to noise pollution. The oysters in the study reacted most strongly to noises between 10 and 1000 hertz, showing the most sensitivity to sounds between 10 and 200 hertz. As Douglas Quenqua at The New York Times reports, those lower frequencies are often produced by cargo ships, seismic research, wind turbines and pile driving. Higher frequencies created by jet skis and small boats, however, did not seem to bother the animals. (***See Exhibit*** 70)

Marine mammals are particularly sensitive to noise pollution because they rely on sound for so many essential functions, including communication, navigation, finding food, and avoiding predators. An expert panel has now published a comprehensive assessment of the available science on how noise exposure affects hearing in marine mammals, providing scientific recommendations for noise exposure criteria that could have far-reaching regulatory implications.[6] (***See Exhibit 71***)

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[5] On 9/17/2019 Supplement to September 16, 2019 Data Request Response Jordan Cove Energy Project L.P. under FERC CP17-495:
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20190917-5151

[6] *Review of noise impacts on marine mammals yields new policy recommendations*
https://www.sciencedaily.com/releases/2019/03/190313143307.htm

Once in operation the LNG facility would be extremely noisy also. Each LNG train would have the potential of emitting 124 dBA [7] and there are 5 trains in all not to mention other components of the facility that would be emitting noise. These issues and the impacts that they would have on the surrounding area and habitat have not been properly addressed properly by the applicant.

Threatened and Endangered Species would be negatively affected

Pacific Connector's April 17, 2019 submittal into the North Bend Conditional Land Use permitting process under File No. **FP2-18 and CBE 3-18 (**electronic page 358 and 359) states the following: (Emphasis has been added)

Green sturgeon
(Southern Distinct Population Segment)
Acipenser medirostris

Short-term increase in noise associated with land based pile driving at the MOF and in-water pile driving at various temporary construction activities throughout the bay may create disturbance and physical injury.

Exposure to suspended sediment during Pipeline construction could affect sturgeon and designated critical habitat.
Slip Access Channel and Navigation Reliability Improvements dredging could reduce food supply for rearing fish in localized areas in Coos Bay

Critical habitat would be adversely affected by reduction in food sources from dredging in Coos Bay for construction of the LNG Terminal.

Coho salmon
(Southern Oregon/Northern California Coast Evolutionarily Significant Unit)
Oncorhynchus kisutch

Juvenile rearing stages would suffer stress and possibly mortality from elevated turbidity at Pipeline stream crossings, from fish salvage operations, and from in-stream blasting. Adult spawning success may also suffer from short-term elevated sediment from Pipeline stream crossings. Designated critical habitat would be adversely affected by reduced large woody debris (LWD) supply and riparian habitat loss and impedance of fish movement during instream construction. **Critical habitat could be adversely affected by increased turbidity during construction**.

Short-term increase in noise associated with land-based pile driving at the MOF and in-water pile driving at various temporary construction activities throughout the bay may create disturbance and physical injury. Juvenile loss from entrainment during LNG carrier water intake in Coos Bay may occur.

Slip, access channel and Navigational Reliability Improvements dredging could reduce food supply for fish in localized areas in Coos Bay and entrain juveniles but is not likely to contribute to significant adverse effects due to there being a small and localized area impacted.

Juvenile rearing stages would suffer stress and possibly mortality from elevated turbidity at Pipeline stream crossings, from fish salvage operations, and from in-stream blasting. Adult spawning

[7] Report: PNG LNG Project - LNG Facilities - Environmental Noise Impact Assessment 1-15-2009 (See page 27) https://pnglng.com/media/PNG-LNG-Media/Files/Environment/EIS/eis_appendix19.pdf

success may also suffer from short-term elevated sediment from pipeline stream crossings. Designated critical habitat could be adversely affected by reduced LWD supply and riparian habitat loss and impedance of fish movement during instream construction. **Critical habitat could be adversely affected by increased turbidity during construction**.

Pacific Connector's North Bend April 17, 2019 submittal electronic page 362 states the following:

Pacific Coast Salmon

Short-term increase in noise associated with land based pile driving at the MOF and in water pile driving at various temporary construction activities throughout the bay may create disturbance and physical injury. Pipeline stream crossings could impact substrates and water quality over the short term, and LWD supply over the long term. Juvenile coho or Chinook salmon entrapped in isolated areas at pipeline stream crossings, as well as removal from stream crossing areas, would result in minor fish mortalities..
(Emphasis added)

OAR 141-122-0020 Policies

(13) ***The Department will not grant an easement if the proposed use or development is inconsistent with any endangered species management plan adopted by the Department under the Oregon Endangered Species Act*** *(ORS 496.171 to 496.192).*
(Emphasis added)

Coos Bay Estuary Management Plan Policy #47 Environmental Quality

The Coos Bay Estuary Management Plan and Implementing Ordinance ***shall comply with the Department of Environmental Quality (DEQ) regulations regarding air, water quality and noise source standards that are established as law***.
(Emphasis added)

CCZLDO SECTION 4.11.400 Southwest Oregon Regional Airport:
*   *   *   *
CCZLDO SECTION 4.11.420 Definitions:

These definitions only apply to Sections 4.11.400 through 4.11.450, the following words and phrases shall mean:

1. *―Airport" means the Southwest Oregon Regional Airport (also referred to as North Bend Municipal) Airport.*
2. *―Airport direct impact area" means the area located within 5,000 feet of an airport runway, excluding lands within the runway protection zone and approach surface.*
3. *―Airport elevation" The most current and approved North Bend Municipal Airport master plan, airport layout plan, defines the highest point of the airport's usable landing area. The 2002 Airport Layout Plan has established the airport elevation as 17.1 feet above mean sea level (reference datum is NAVD 88).*
4. *―Airport imaginary surfaces" means imaginary areas in space and on the ground that are established in relation to the airport and its runways. Imaginary areas are defined by the*

primary surface, runway protection zone, approach surface, horizontal surface, conical surface and transitional surface.

5. *—**Airport noise impact boundary" means areas located within 1,500 feet of an airport runway or within the most current, established noise contour boundaries exceeding 55 Ldn**. 4. —Airport secondary impact area" means the area located between 5,000 and 10,000 feet from the airport's runways.*

*   *   *   *

CCZLDO SECTION 4.11.425

*Imaginary surface and noise impact boundary delineation: The airport elevation, the airport noise impact boundary, and the location and dimensions of the runway, primary surface, runway protection zone, approach surface, horizontal surface, conical surface and transitional surface is delineated for the airport by the most current, and approved North Bend Municipal Airport master plan and airport layout plan, the airport master plan along with the associated maps and documents are made part of the official zoning map of the city of North Bend and Southwest Oregon Regional Airport Surface (NB/AS) Inventory Map for Coos County. **All lands, waters and airspace, or portions thereof, that are located within these boundaries or surfaces shall be subject to the requirements of this overlay zone**.*

See more issues with respect to airport overlay issues further below.

BOXCAR HILL LAYDOWN AND CEMENT BATCH PLANT IN IND ZONE

According to the staff report:

> *The uses and activities in this section are subject to Balance of County Industrial Zone subject to the Coos County Zoning and Land Development Ordinance (CCZLDO) all uses in the Industrial Zones are subject to compliance with Sections 4.3.200, 4.3.220, 4.3.225, 4.3.330 and Special Development Considerations and Overlays identified in Section 4.11(Section 4.11 is only applicable if a development or structure is identified as located in a mapped development consideration or overlay area and some mapped hazard areas are required to address Section 5.11 Geological Assessments):*

The applicant has NOT provided any geological assessment and what is being proposed by the applicant is not compatible with surrounding recreational properties. They have also not provided a traffic or noise assessment as is required in this zoning.

CCZLDO Section 4.3.220 *Additional Conditional Use Review Standards for uses, development and activities listed in table 4.3.200*

*   *   *   *

(6) Industrial (IND) and Airport Operations (AO)

*   *   *   *

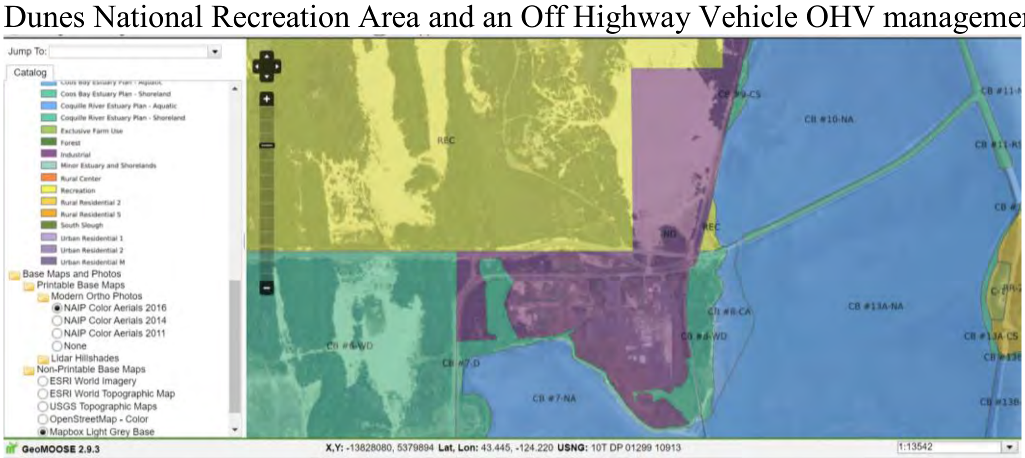
(f) Conditional Use Review Criteria - The following criteria only apply to Use, Activity or Development identified as a conditional uses in the zoning table:

*i. COMPATIBILITY: The proposed USE, ACTIVITY OR DEVELOPMENT **is required to demonstrate compatibility with the surrounding properties** or compatibility may be made through the imposition of conditions. **Compatibility means that the proposed use is capable of existing together with the surrounding uses without discord or***

disharmony. *The test is where the proposed use is compatible with the existing surrounding uses and not potential or future uses in the surround area.*

Oregon Dunes National Recreation Area shown below (***See Exhibit 72***)

Despite the Boxcar Hill campground area being zoned Industrial it is considered a part of the Oregon Dunes National Recreation Area and an Off Highway Vehicle OHV management area.

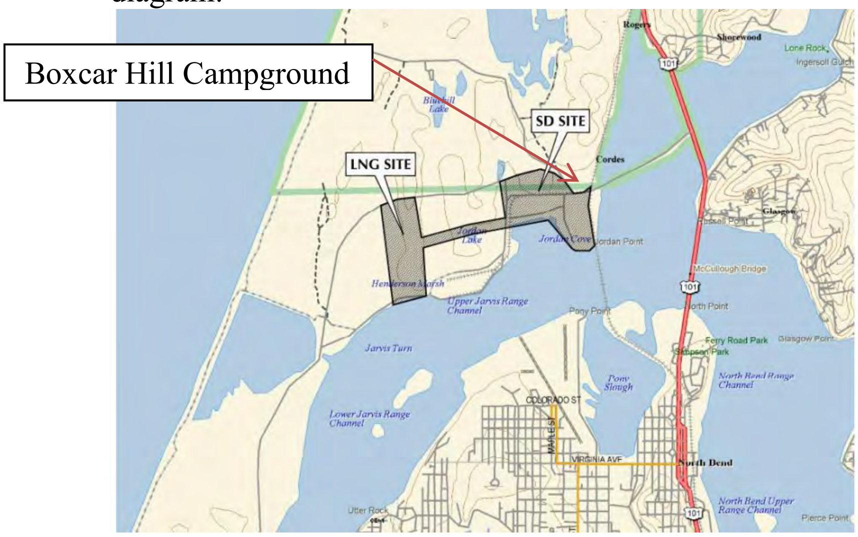


Thousands of people come and visit the Dunes National Recreation Area every year. (***See Exhibit 73)*** Building a cement batch plant at the very sand hill that many people use with their ATV's (Alternative Terrain Vehicles) and UTV's (Utility Task Vehicles) is a destruction of use NOT a Compatible Use as is required under **CCZLDO Section 4.3.220 (6)(f)**

According to Jordan Cove's DSL Application Electronic page 676 states:

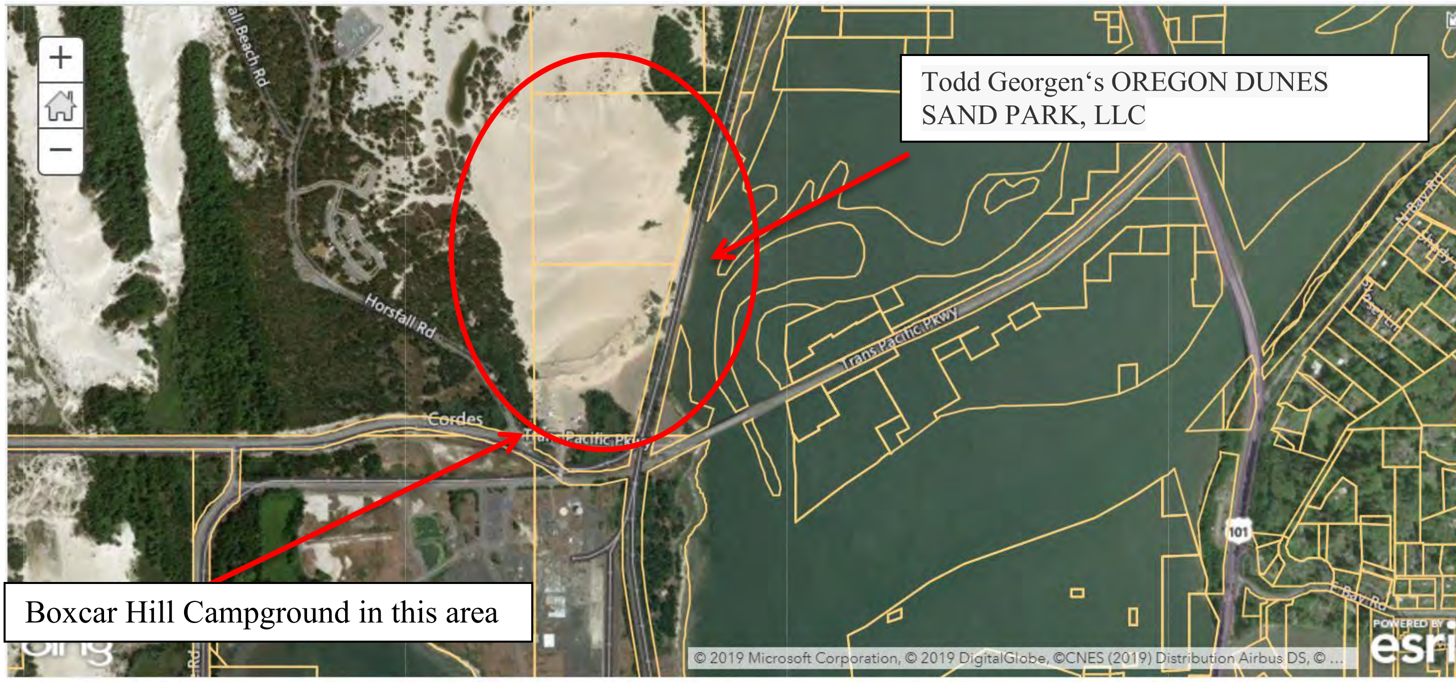
- *Approximately 10 acres at the Box Car Hill site will be used for temporary offices, parking, and a temporary concrete batch plant.*

Page 123 of Jordan Cove's 1-12-2016 submittal under file No. HBCU-15-05 had the following diagram:



There are 65 spaces at the Boxcar Hill camping area that is directly next to the proposed Jordan Cove South Dunes Power Plant. Jordan Cove was leasing the entire Boxcar Hill Campground on the North Spit with plans to sign a 99 year lease in the near future due to this area being a noise sensitive property if their proposed LNG facility should proceed. (***See Exhibit 43***) The Boxcar Hill camping area is currently used all year long by people visiting the Dunes. Taking it out of service would detour future visitors from coming to camp, ride and play in our Dunes National Recreational Area. This would cost jobs and negatively cause harm to our tourism and recreation industries.

The heavily used Boxcar Hill camping area below would be negatively affected by the Jordan Cove project should it proceed. What Jordan Cove is proposing is not a Compatible Use:



Page 749 from Jordan Cove's DSL application shows the campground to be a laydown area for Jordan Cove:

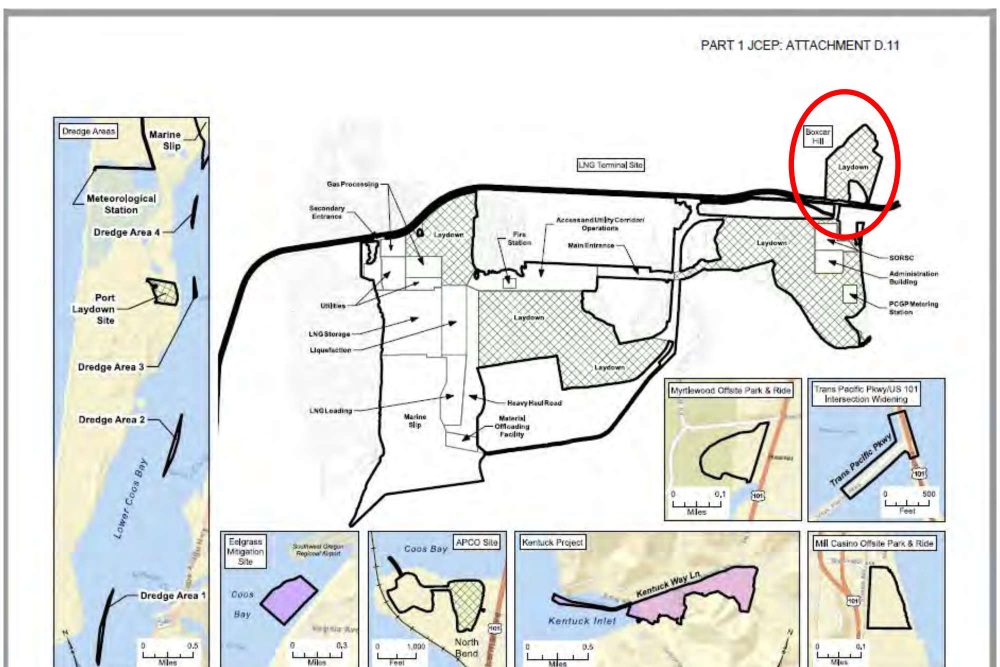


FIGURE 3
DISTURBED AREAS
J1-000-RGL-PMT-DEA-00003-00 Rev. F

Boxcar Hill Campground Expansion Project -vs- JCEP Personal Cement Plant

In 2017 Todd Georgen applied for and obtained a permit to extend the Oregon Sand Park Campground and add another 250 Camping spaces.[8] (***See Exhibit 21 and 22***)

What Jordan Cove is proposing with their Cement batch plant and offices **will take out some 250 planned Camping sites that had been approved and 65 current camping sites at Boxcar hill campground directly south of the Dunes National Recreation Area**. **This would be a loss of Recreational opportunities for many people**. The staff report that was prepared for the proposed expanded campground area stated that was a compatible use due to the property to the west being in federal ownership and used for recreation purposes.

There are lots of negative impacts to nearby towns that allow LNG terminals and work camps for the temporary workers. In 2007 when Royal Dutch Shell built an LNG export terminal on Russia's Sakhalin Island an article in Fortune magazine entitled ―*Shell Shakedown*" about the Gazprom takeover of the project stated the following with respect to what happened to the locals in that area: (***See Exhibit 14***)

> *…Residents say the company led them to believe that housing for 6,000 construction workers would be located in the town, where it could later be reused by the community, which sorely needs it.* ***Many people in Korsakov earn less than $300 a month - a sharp contrast to the wealth of Sakhalin Energy employees, many of whom, especially those who come from other countries, make more than $1,000 a day****.*
>
> *But when construction began, Sakhalin Energy built its housing for workers next to the plant itself, inside a one-kilometer safety zone, where it will be illegal for people to live once operations begin. "People here could use this place for their well-being, and it will be demolished," says Elena Lopukhina, director of a Korsakov advocacy group and an assistant to a regional government official, who says that is just one of the emotional issues in the community that have swayed people against Sakhalin Energy. "****The company did everything that was good for them and not good for us****."*
>
> *…Still, there are the small things - the $4 pencils and $500 space heaters a customs officer says she saw listed on a Sakhalin import form, the flaunting of money by expatriate staff in downtown nightclubs, the waxed and polished Land Cruiser fleet lined up in an island parking lot* ***- that give Sakhaliners a feeling of watching a party in their living room to which they haven't been invite.***
>
> *If Sakhaliners think spending is out of control, that could explain why prices in Yuzhno also seem divorced from reality...* ***…houses can cost nearly $1 million, while a one-bedroom***

[8] Oregon Sand Park Application:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/application.pdf?ver=2017-05-02-144014-527
Coos County Decision of approval:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/ACU-17-009%20Notice%20of%20Decision%20and%20Staff%20Report.pdf?ver=2017-05-02-144013-753
Amended notice of approval to reflect the correct map of the property:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/amended%20notice%20of%20decision.pdf?ver=2017-05-02-144014-237

apartment can rent for $3,000 a month, comparable to New York City prices*. A five-minute taxi ride costs $12, and lunch at a casual Indian restaurant starts at about $40 per person.*[9]

GAS PROCESSING IN THE 6-WD ZONE

The Amine regenerator column includes a thermal oxidizer stack.

Jordan Cove's Revised September 2017 RR#1 states on page 20:

> *The CO2 removed from the feed gas is to be* ***vented to the atmosphere****, but the vent stream must first be treated for co-absorbed contaminants. To limit emissions, absorbed H2S and other sulfur species in the vent stream will be thermally oxidized after passing through the sulfur scavenger unit. Co-absorbed hydrocarbons, including benzene, toluene, ethylbenzene, and xylenes, will also be* ***combusted and destroyed in the thermal oxidizer****.* (Emphasis added)

According to Wikipedia:

> *Most direct-fired thermal oxidizers operate at temperature levels between 980 °C (1,800 °F) and 1,200 °C (2,190 °F) with air flow rates of 0.24 to 24 standard cubic meters per second.[1]*

This puts a CONSIDERABLE HAZARD IN THE FLIGHT PATH OF THE AIRPORT The airport, pilots, local residents, tourist and other visitors to the area are being placed at risk.

CCZLDO SECTION 4.11.345 Conformance Requirement:

> ***All structures and uses within the Airport Operations District shall conform to the requirements of Federal Aviation Agency Regulation FAR-77 or its successor, and to other Federal and State laws as supplemented by Coos County Ordinances regulating structure height, steam or dust, and other hazards to flight, air navigation or public health, safety and welfare****.*

The FAA has also stated that it is the County's responsibility to deal with airport hazards. (***See Exhibit 74*****)**

On May 7, 2018 the FAA released 13 determinations of PRESUMED AIRPORT HAZARD with respect to the proposed Jordan Cove Project.[10] Jordan Cove **has not resolved these issues** and they do not appear that they are able to be mitigated. See more information about this further below. (***See Exhibit 1***) Presumed Airport Hazards included but are not limited to the following:

- Amine Regenerator - 2017-ANM-5389-OE
- Oxidizer - 2017-ANM-5388-OE

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[9] *Shell shakedown - Fortune's Abrahm Lustgarten reports how the world's second-largest oil company lost control of its $22 billion project on Russia's Sakhalin Island*. By Abrahm Lustgarten; Fortune; February 1, 2007 http://archive.fortune.com/magazines/fortune/fortune_archive/2007/02/05/8399125/index.htm

[10] See Part 8 of Jordan Cove response filing with the FERC that includes the 13 FAA documents: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180510-5165

CCZLDO SECTION 4.11.435 Height limitations on allowed uses in underlying zones:

All uses permitted by the underlying zone shall comply with the height limitations in this section.

1. ***<u>A person may not construct an object or structure that constitutes a physical hazard to air navigation, as determined by the Oregon Department of Aviation in coordination with the governing body with land use jurisdiction over the propert</u>****y.*

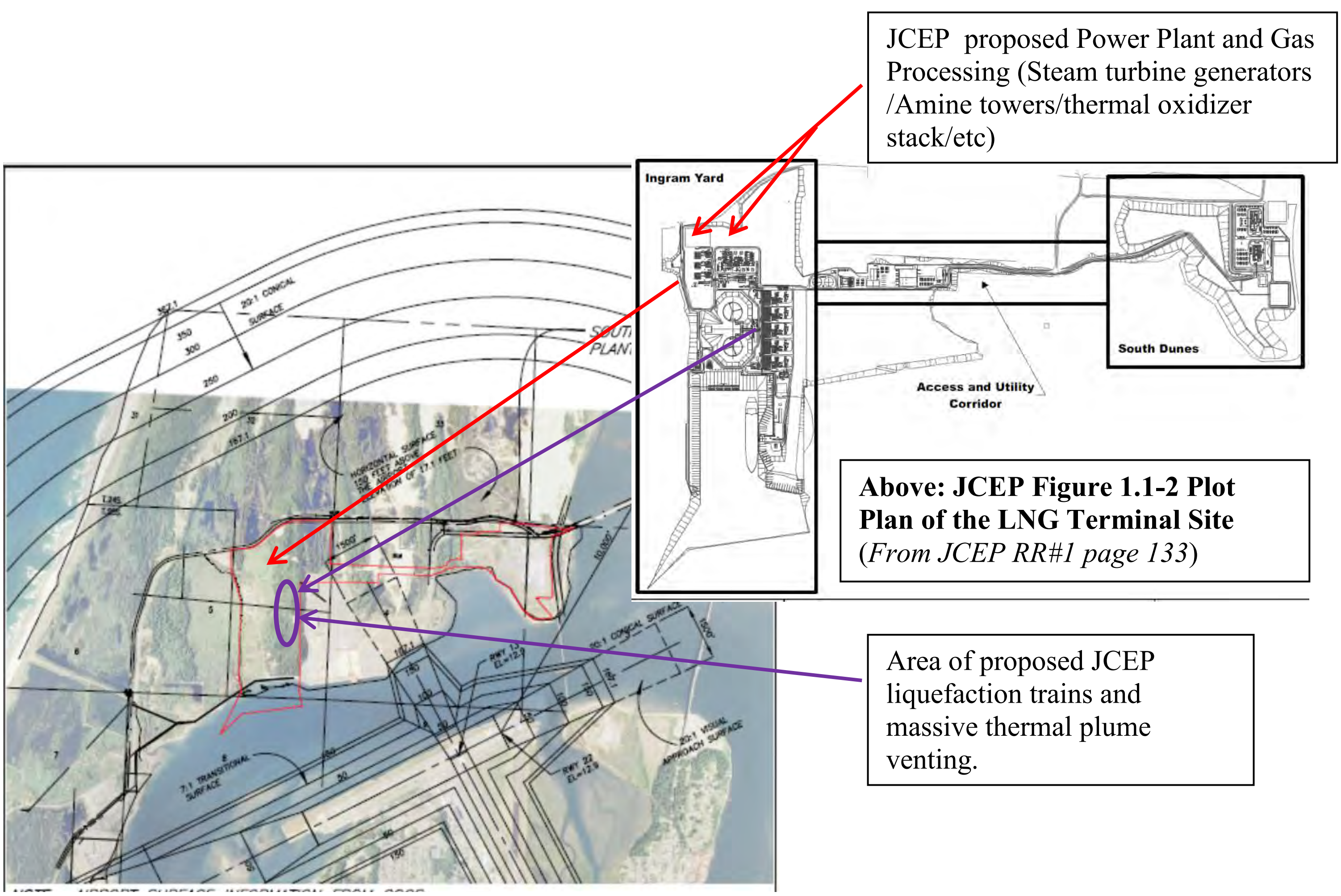
2. Subsection (1) of this section does not apply:

a. To construction of an object or structure that is utilized by a commercial mobile radio service provider; or

b. If a person received approval or submitted an application for approval from the Federal Aviation Administration or the Energy Facility Siting Council established under ORS 469.450 to construct an object or structure that constitutes a physical hazard to air navigation. A variance application will not be required if such application was made.

Jordan Cove has not complied with this section.

Below find Southwest Oregon Regional Airport (Partial) Overlay



Above: JCEP Figure 1.1-2 Plot Plan of the LNG Terminal Site (*From JCEP RR#1 page 133*)

Above overlay diagram from Jordan Cove Figure 15 filed Dec 17 2015 under HBCU-15-05

CCZLDO SECTION 4.11.440 Procedures:

An applicant seeking a land use approval in an area within this overlay zone shall provide the following information in addition to any other information required in the permit application:

1. A map or drawing showing the location of the property in relation to the airport imaginary surfaces. The airport authority shall provide the applicant with appropriate base maps upon which to locate the property

2. Elevation profiles and a plot plan, both drawn to scale, including the location and height of all existing and proposed structures, measured in feet above mean sea level (reference datum NAVD 88).

There are NO elevation drawings that I could find in with this application. We do not really know how much fill they are proposing which makes it hard to determine if they comply with other components of the project.

In addition to thermal plumes coming from the liquefaction trains the proposed facility would have two 30-megawatt steam turbine generators and one spare 30 MW steam turbine generator, (DEIS 2-7) two diesel black-start generators, two diesel backup generators, and three diesel fire pump engines, (DEIS page 4-659) Amine regenerator column and thermal oxidizer stack, (DEIS page 4-750) aerial coolers, air-cooled condensers, gas flares, auxiliary boiler, LNG storage tank venting, etc, etc. (DEIS 4-670-671, 4-686)

DEIS page 2-7 states:

> *Electrical power to the LNG terminal would be supplied via two 30-megawatt (MW)* ***steam turbine generators*** *and one spare 30 MW steam turbine generator, with the steam generated by heat recovery from gas turbine operation. A black-start auxiliary boiler would be used to generate steam for power when gas turbines are not in operation. The system would also include two standby diesel generators for the LNG facility and two for the SORSC.* (Emphasis added)

DEIS page 4-659:

> *The natural gas–fired turbines at the Jordan Cove LNG Project are subject to NSPS Subpart KKKK,* ***which limits emissions of NO_x from the turbines****.*
>
> *The auxiliary boiler is subject to NSPS Subpart Db,* ***which applies to steam-generating units rated at greater than 100 MMBtu/hr heat input****. The auxiliary boiler would be subject to the Subpart Db emission limit for NO_x* ***but would be exempt from the Subpart Db emission limits for sulfur dioxide (SO_2) and particulate matter because it would burn only natural gas.***
>
> ***The two diesel black-start generators, two diesel backup generators, and three diesel fire pump engines are subject to NSPS Subpart IIII, which requires that new or modified stationary engines meet the same emissions standards that manufacturers of comparable nonroad engines are required to comply with****. Jordan Cove has proposed to install engines that meet EPA Tier 2 emission standards for the diesel generators, and EPA Tier 3 emission standards for the diesel fire pump engines.*
>
> (Emphasis added)

DEIS page 4-670:

TABLE 4.12.1.3-2

Estimated Emissions During Operation of the Jordan Cove LNG Project (tons per year)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	HAP	GHG (as CO_2e)
Combustion Turbines	97.82	81.99	35.19	32.72	112.26	112.26	5.06	1,292,706
Combustion Turbines Startup/Shutdown	0.73	0.23	4.4E-03	0.10	0.11	0.11	6.2E-04	188
Thermal Oxidizer	38.50	63.25	19.84	1.08	3.85	3.85	0.96	622,154
Auxiliary Boiler	1.16	0.96	0.36	0.67	1.3	1.3	0.24	15,193
Firewater Pump Engines	0.80	1.59	2.1E-03	4.5E-02	9.0E-02	9.0E-02	3.6E-03	241
Backup Generator Engines	0.28	3.33	2.5E-03	0.04	0.04	0.04	4.1E-03	278
Black Start Generator Engines	0.21	1.49	8.8E-03	0.09	0.05	0.05	1.5E-02	1,002
Flares	3.90	0.86	3.9E-02	8.31	0.38	0.38	4.3E-02	2,177
Gas-Up	9.5	2.09	0.16	17.53	1.12	1.12	3.8E-02	4,351
Fugitive Emissions	0	0	0	7.98	0	0	1.77	13,116
Aggregate Insignificant Emissions	1.0	1.0	1.0	1.0	1.0	1.0	--	--
LNG Carriers a/	36.68	48.68	9.5	9.47	3.31	3.31	--	14,653
Tugs	17.68	9.51	2.6	1.00	0.32	0.32	--	3,736
Total	**208.26**	**214.98**	**68.71**	**80.04**	**123.83**	**123.83**	**8.13**	**1,969,795**

a/ Values are based on 120 vessel calls per year, assuming worst-case emissions (i.e., vessel type with the highest emissions) for each pollutant. Emissions estimated at 2.2 nautical miles from the Oregon coastline.

DEIS page 4-671:

Routine Operation: *The following sources are expected to operate continuously during routine operation:*

- *five combustion turbines for the refrigeration compressors;*
- *one thermal oxidizer;*
- *flare pilot flames for the enclosed marine flare and multipoint ground flare;*
- *two LNG storage tanks; and*
- *fugitive emission sources (valves, flanges, and other equipment).*

Intermittent Operation: *The following sources or activities would only operate intermittently. The auxiliary boiler would provide high-pressure steam if none of the LNG trains are operating, and the other intermittent sources would only operate during startup or shutdown events, planned maintenance, process upsets, readiness testing, or emergency situations:*

- *combustion turbine startup and shutdown events;*
- *one auxiliary boiler;*
- *one enclosed marine flare;*
- *one multipoint ground flare;*
- *two diesel black-start engines;*
- *two backup engines;*
- *three fire water pump engines; and*
- *up to 120 LNG carriers per year, with one tugboat attending each carrier.*

DEIS page 4-686:

> ***Operational Noise Impacts***
> *Operational noise associated with the Jordan Cove Project was modeled using noise prediction software (CadnaA version 2017) in accordance with ISO 9613. The following major oiseproducing equipment would normally be in operation at the Jordan Cove LNG Project and were included in the acoustic modeling analysis:*
>
> - *Five refrigerant compressors, combustion turbines, heat recovery steam generators, and associated piping;*
> - *Refrigerant compressor interstage and* ***discharge aerial coolers****;*
> - *Three steam turbines and their associated* ***air-cooled condensers****;*
> - *Two BOG compressors with interstage and* ***discharge aerial coolers****; and*
> - *Various other smaller condensers, coolers, pumps and valves.*
>
> (Emphasis has been added)

Concerning the above, the DEIS states on page 4-687 the following:

> *As currently designed, Jordan Cove would not install additional noise mitigation measures such as acoustical enclosures, acoustical barriers, or custom silencers beyond mitigation inherent to the specified equipment analyzed.*

So not only would we be dealing with massive heat venting and thermal plumes directly in the vicinity of the airport runway approach surface, but we would also be dealing with enormous levels of noise that the Jordan Cove Project has no plans whatsoever to mitigate. In addition, gas processing facilities are very dangerous. There have been numerous accidents at these types of facilities over the years that have caused extensive damage. (*See Exhibit 24*)

NOISE

Once in operation the LNG facility would be extremely noisy also. Each LNG train would have the potential of emitting 124 dBA [11] and there are 5 trains in all not to mention other components of the facility that would be emitting noise. These issues and the impacts that they would have on the surrounding area and habitat have not been addressed properly by the applicant.

Jordan Cove's September 17, 2019 filing with the FERC showed that their pile driving could create noise levels of up to 75 dBA.[12] See Diagram above on page 15. This would exceed the requirements for noise in the airport's overlay zones.

[11] Report: PNG LNG Project - LNG Facilities - Environmental Noise Impact Assessment 1-15-2009 (See page 27) https://pnglng.com/media/PNG-LNG-Media/Files/Environment/EIS/eis_appendix19.pdf

[12] On 9/17/2019 Supplement to September 16, 2019 Data Request Response Jordan Cove Energy Project L.P. under FERC CP17-495:
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20190917-5151

SECTION 4.11.445 LAND USE COMPATIBLITY REQUIRMENTS:

Applications for land use or building permits for properties within the boundaries of this overlay zone shall comply with the requirements of this section as provided herein:

1. Noise. Within airport noise impact boundaries, land uses shall be established consistent with the levels identified in OAR 660, Division 13, Exhibit 5. A declaration of anticipated noise levels shall be attached to any subdivision or partition approval or other land use approval or building permit affecting land within airport noise impact boundaries. In areas where the noise level is anticipated to be at or above 55 Ldn, prior to issuance of a building permit for construction of a noise sensitive land use (real property normally used for sleeping or as a school, church, hospital, public library or similar use), the permit applicant shall be required to demonstrate that a noise abatement strategy will be incorporated into the building design that will achieve an indoor noise level equal to or less than 55 Ldn.

There is also no proof in the application that Jordan Cove is incompliance with the rest of the regulations either under Section 4.11.445:

2. Outdoor Lighting. No new or expanded industrial, commercial or recreational use shall project lighting directly onto an existing runway or taxiway or into existing airport approach surfaces except where necessary for safe and convenient air travel. Lighting for these uses shall incorporate shielding in their designs to reflect light away from airport approach surfaces. No use shall imitate airport lighting or impede the ability of pilots to distinguish between airport lighting and other lighting.

3. Glare. No glare producing material, including but not limited to unpainted metal or reflective glass, shall be used on the exterior of structures located within an approach surface or on nearby lands where glare could impede a pilot's vision.

4. Industrial Emissions. No new industrial, mining or similar use, or expansion of an existing industrial, mining or similar use, shall, as part of its regular operations, ***cause emissions of smoke, dust or steam that could obscure visibility within airport approach surfaces****, except upon demonstration, supported by substantial evidence, that mitigation measures imposed as approval conditions will reduce the potential for safety risk or incompatibility with airport operations to an insignificant level.* ***The review authority shall impose such conditions as necessary to ensure that the use does not obscure visibility****.*

5. Landfills. No new sanitary landfills shall be permitted within 10,000 feet of any airport runway. Expansions of existing landfill facilities within these distances shall be permitted only upon demonstration that the landfills are designed and will operate so as not to increase the likelihood of bird/aircraft collisions. Timely notice of any proposed expansion shall be provided to the airport sponsor, the Department of Aviation and the FAA, and any approval shall be accompanied by such conditions as are necessary to ensure that an increase in bird/aircraft collisions is not likely to result.

6. Communications Facilities and Electrical Interference. Proposals for the location of new or expanded radio, radiotelephone, television transmission facilities and electrical transmission lines within this overlay zone shall be coordinated with the Department of Aviation and the FAA prior to approval.

The application is INCOMPLETE and does not provide enough data to determine if the project is in compliance with the above codes and several others. There has been no thermal plume study provided nor drawings of project components detailed enough to be able to make the above determinations. We do know that the Amine thermal oxidizer WILL be emitting large volumes of emissions as will also the gas flares necessary for safety measures of the Jordan Cove gas processing facility including Amine towers and thermal oxidizers. These are very noisy processes but Jordan Cove has not provided any noise impact assessment.

Depending on how much fill will be under these project components they are likely to not be in compliance with CBEMP Policy 48 for building on weak foundation soils.

CCZLDO SECTION 4.11.440 Procedures:
An applicant seeking a land use approval in an area within this overlay zone shall provide the following information in addition to any other information required in the permit application:

> *1. A map or drawing showing the location of the property in relation to the airport imaginary surfaces. The airport authority shall provide the applicant with appropriate base maps upon which to locate the property.*
>
> *2. **Elevation profiles and a plot plan, both drawn to scale, including the location and height of all existing and proposed structures, measured in feet above mean sea level (reference datum NAVD 88).***

CBEMP Policy #48 Weak Foundation Soils

> *The State Department of Commerce, Building Codes Division (pursuant to the authority vested in it by Section 2905 of the State Structural Specialty Code) **shall require an engineered foundation or other appropriate safeguard deemed necessary to protect life and property in areas of weak foundation soils**.* (Emphasis added)
>
> *This strategy recognizes it is the responsibility of the State of Oregon Department of Commerce, Building Codes Division to determine, based on field investigations, whether safeguards are necessary to minimize potential risks. The general level of detail used in mapping areas known as weak foundation soils is not of sufficient scale to mandate specific safeguards prior to a field investigation by the Building Codes Division.*

The diagrams of project components that have been provided do not include the heights of the structures and ARE NOT EVEN LEGIBLE. (See applicant Exhibit 9 pages 26 and 27) These project components diagrams should have been rejected by the Planning Department. The airport overlay diagrams they have provided (Applicant Exhibits 12 and 13) do not even show project components at all. There should also be professional people looking at these issues before land use compliance has been determined in order to protect the public health, safety and welfare of local residents and tourist .

TEMPORARY WORKFORCE HOUSING IN THE IND ZONE

Jordan Cove does not provide enough information concerning their proposed ―temporary” workforce housing to make a land use determination. From what we can gather from Jordan Cove's website and their FERC Draft EIS, they do not have enough required parking and would place commercial convenience centers in Industrial zones.

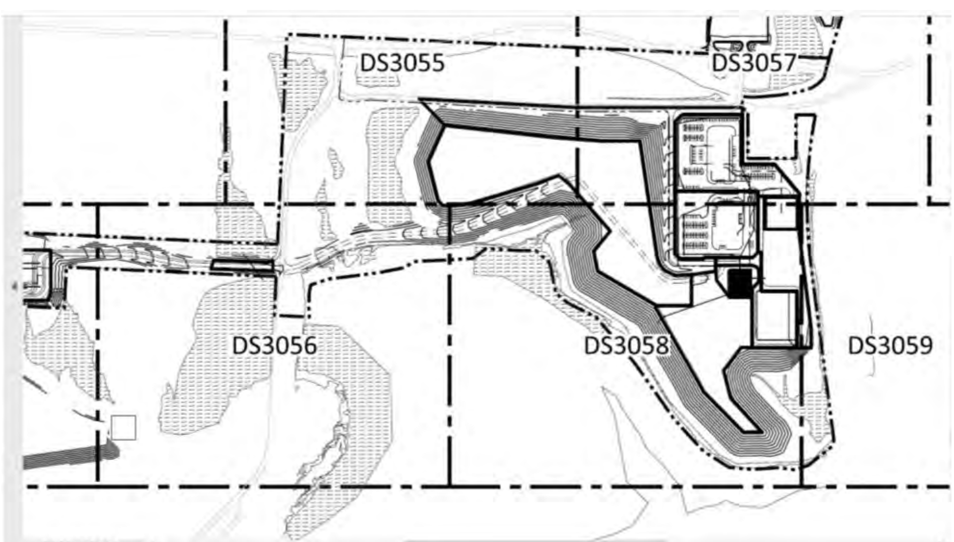
CCZLDO Section 4.3.210 – CATEGORIES and review standards

(61) Mobile/manufactured home parks – New and modified mobile/manufactured home parks shall meet the following criteria:

(k) ORS 197.490 Restriction on establishment of park: (i) Except as provided by ORS 446.105, a mobile home or manufactured dwelling park shall not be established on land, within an urban growth boundary, which is planned or zoned for commercial or industrial use. (ii) Notwithstanding the provisions of subsection (1) of this section, if no other access is available, access to a mobile home or manufactured dwelling park may be provided through a commercial or industrial zon

(64) Offices- This category includes administrative and corporate offices and call centers. These businesses primarily serve other industries or deliver their products and services to the end user through means other than on-site customer visits. This use shall be an accessory use to another industrial use or uses. Few general public customer visits per day are generated.

Jordan Cove's proposed Worker Camp would sit on an active (Weyerhaeuser) toxic landfill area in the Industrial Zoning District. These mobile structures could be considered a manufactured dwelling park which is NOT ALLOWED in the IND zone. In addition, the Industrial Solid Waste Landfill (ISWL) at the former mill is regulated under the Oregon Department of Environmental Quality (DEQ) Solid Waste Permit Number 1142 (Solid Waste Permit). The Solid Waste Permit remains active, and was renewed on November 2, 2011 with an expiration date of August 31, 2021. There has been no geological assessment provided as required by CCZLDO ARTICLE 5.11 GEOLOGIC ASSESSMENT REPORTS. If the following is Jordan Cove's idea of elevation drawings, they are not sufficient and provide no real data.



According to Jordan Cove's *Final Closure Plan, North Spit Landfill Cell 3, North Bend, Oregon,* prepared by SHN date October 2015 states on pages 1 and 2:

Landfill Cell 1 was closed and capped in September 1988. Landfill Cell 2 was constructed in 1988 and is authorized to receive old corrugated containers (OCC) waste, wire, plastic, fiber, sand, dirt, settling basins solids, construction and demolition debris generated at the site, and *miscellaneous cleanup wastes of similar nature. Cell 2 also received asbestos waste from the demolition waste created during mill closure. Cell 2 is still considered open and has some remaining capacity for additional waste before reaching the authorized final grades.*

Landfill Cell 3 was considered the landfill expansion area and was designated primarily for the disposal of OCC waste, effluent treatment solids, boiler ash, and the 2005 demolition material from the former Weyerhaeuser Mill structures. Landfill Cell 3 surface area covers approximately 5.8-acres (330 feet by 750 feet), and is defined by a perimeter berm that extends to a height of approximately 5 feet above the existing ground surface. An interim covering consisting of onsite sand was placed over the waste after placement of the demolition debris in 2005. The current appearance of Cell 3 is an elevated mound on the eastern half of the cell with varying slope gradients and a relatively level area over the western half of the cell. The interim cover is vegetation consisting of low-lying grasses.

Cell 3 is underlain by a leachate collection system that consists of a network of perforated pipes surrounded by porous gravel underlain by an impermeable geosynthetic liner. The leachate from Cell 3 drains to two (2) settling basins located just east of the landfill cell. The wastewater in the settling basins is then pumped to a lagoon and eventually discharged through the permitted ocean outfall. The Wastewater Treatment Facility (WWTF) discharge is regulated under the National Pollution Discharge Elimination System (NPDES) permit number 101499 (NPDES Permit).

Most recently, in the fall of 2014, JC LNG and SHN, in cooperation with the DEQ, conducted a pilot waste removal and trucking project to determine if excavation, demolition debris recycling, and offsite disposal of the waste in Cell 3 was feasible. This pilot project excavated, processed and hauled approximately 2,300 tons of waste. The disturbed areas were subsequently covered with at least 12-inch of on-site soils. A summary report of the pilot project results was provided to the DEQ in a letter dated January 9, 2015. In accordance with the Permit, JC LNG will notify DEQ prior to any future waste removal activities….

***See Exhibit** 75* for a diagram of the Weyco landfill areas on the South Dune property**. Building a worker camp on top of a landfill area is NOT a compatible use and would not be in compliance with CCZLDO 5.11; 4.3.210;** along with other County regulations for protecting the public health, safety and welfare of citizens.

Page 12 of Jordan Cove's April 11, 2019 application states the following:

Only IND-zoned areas of the site will be used for parking and pick-up/drop-off and JCEP will not make physical alterations to the site. JCEP understands there is currently at this site an ongoing parking violation associated with recreational vehicles. JCEP will, in conjunction with its use of the site as a pick-up/drop-off/parking location, remedy this ongoing violation.

In other words, Jordan Cove plans to stop any and all recreational activity even though their property would border the Dunes National Recreation Area. „,? This alone shows that they are not a compatible use and would not be in the public interest.

Jordan Cove's April 11, 2019 application Exhibit 4, page 1 of 1 has the following diagram of their proposed worker camp:

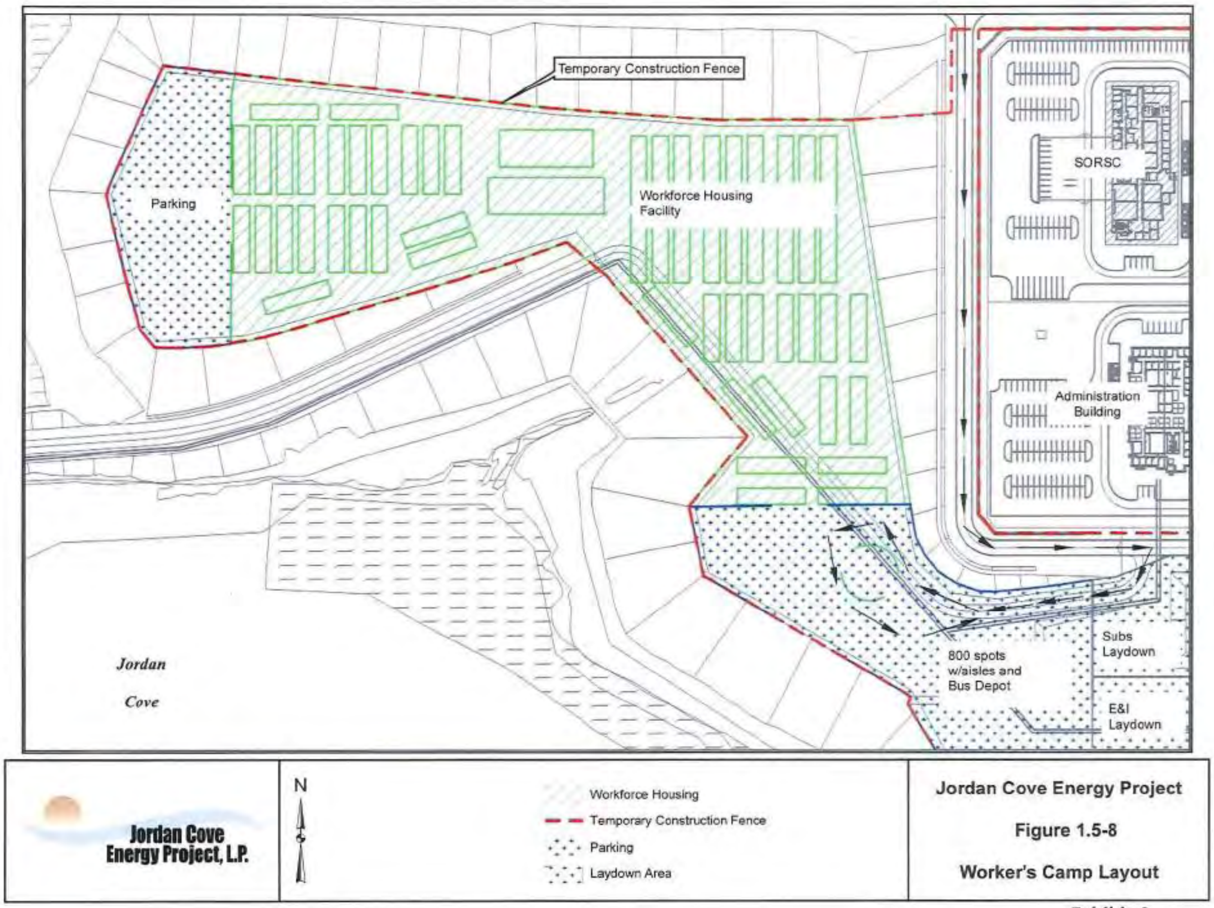


Exhibit 4
Page 1 of 1

Not one place in the application does Jordan Cove state how many workers would be located at their proposed South Dunes Power Plant workforce housing location.

Jordan Cove's website states the following:
https://www.jordancovelng.com/benefits/jobs-and-training

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jordancovelng.com/benefits/jobs-and-training

PROJECT BENEFITS LANDOWNERS ENVIRONMENT SAFETY STORIES NATURAL GAS FACTS

— Direct Employment

During construction, the Jordan Cove Project will create more than 6,000 good-paying construction jobs at peak. This will include approximately 1,000 jobs per year during the construction of the LNG Terminal, and approximately 1,400 jobs per year for the construction of the pipeline.

Once construction is complete, the Project will continue to require more than 200 people to operate the LNG Terminal, pipeline and offices in Coos Bay, Medford and Portland.

— Indirect and Induced Jobs

The Jordan Cove Project will revitalize the local economy throughout Southern Oregon and the South Coast.

During construction the Project would create over ~8,500 spin off jobs in sectors like hospitality, retail, tourism, and healthcare, including ~1,500 permanent spin-off jobs during operations.

Jordan Cove Revised Resource Report (RR) #1 Page 35: (Electronic page 76)

> *Laydown, Workforce Housing Facility and Parking (South Dunes) 71.5 acre site*

JC Revised RR#1 Page 67: (Electronic page 108-109)

> *1.5.9.1 Workforce Housing Facility*
> *The workforce housing facility was originally planned for the North Point Site in North Bend adjacent to the suburb of Simpson Heights. After consultation with the community and further design development of the facility, an alternate site on the South Dunes Site has been allocated. The workforce housing facility will house personnel, primarily tradesman and supervision who do not live within the community or within private accommodations. The current plan is for a facility that can be built out in 100-bed phases,* ***from an initial 200 to a <u>maximum of 700 with</u>***

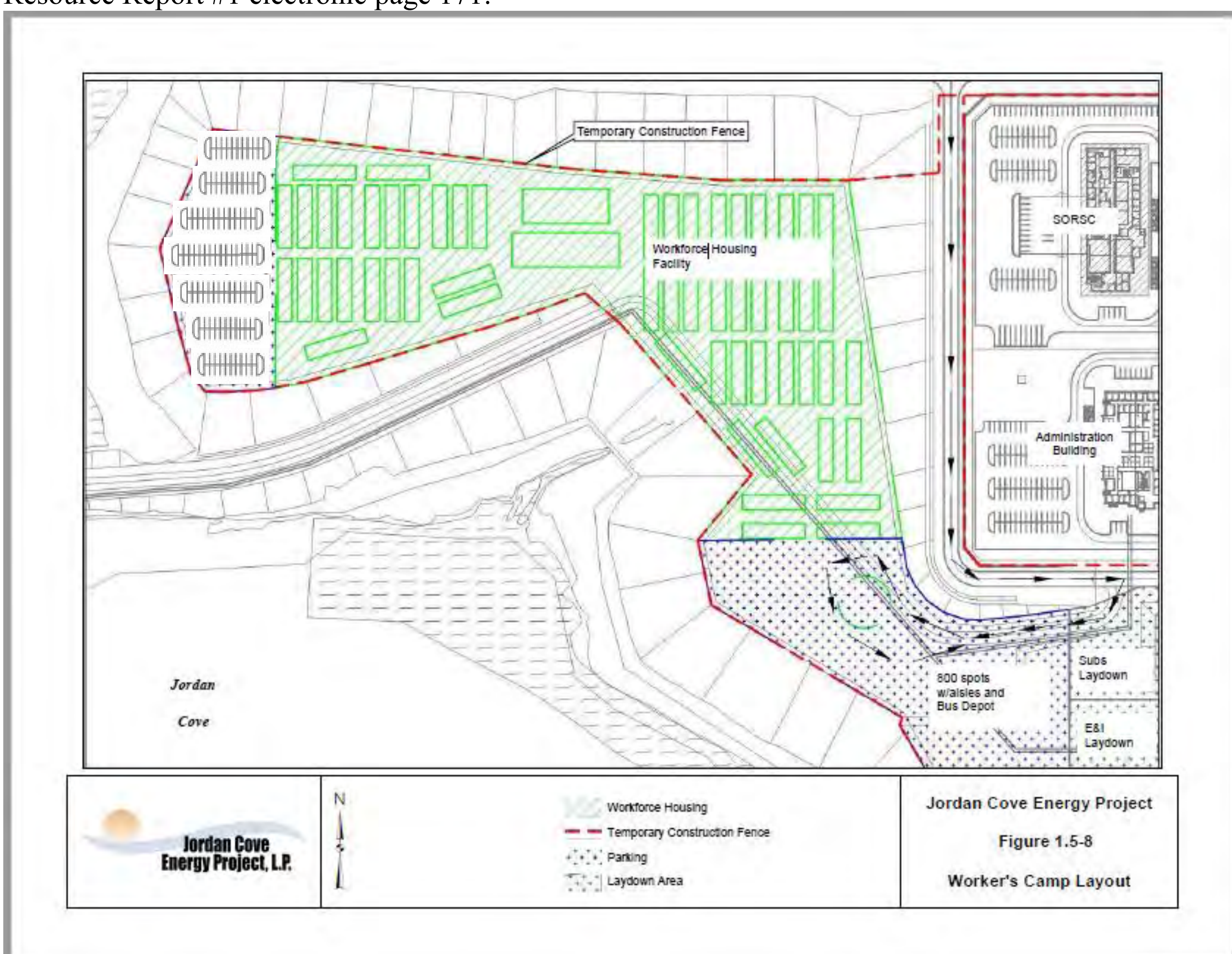
all common facilities built out in the first phase. *An example layout is provided in Figure 1.5-8.*

Parking will be provided on-site, and shuttle buses to and from local communities will reduce traffic on the road network after working hours.

After completion of construction and commissioning activities the entire facility would be decommissioned and removed from the site.

I did a copy and paste of the parking spaces from the SORSC and placed them in the Workforce housing allocated parking area to the west. Below find the altered diagram of approximately 164 spaces. There could possibly be a few more added but clearly there is not room enough for 700 spaces and if there is where are the detailed drawing show this? Just saying on a diagram that there are 800 spots is not sufficient.

Altered diagram below (of proposed workforce parking area) is of JC Figure 1.5-8 from JC Revised Resource Report #1 electronic page 171:



CCZLDO SECTION 7.5.175 REQUIRED NUMBER OF PARKING SPACES FOR TYPE OF USE

Motel, hotel, rooming or boarding house : **1 space per guest accommodation plus 1 space per employee**

Jordan Cove DOES NOT meet this requirement as far as I can tell. The 9-25-2019 signed form under DR-19-033 from Coos County Roadmaster Scott Murray has no empirical data to support such an assumption and should be withdrawn. It does not comply with County regulations with respect to Coos County requirements for parking spaces under CCZLDO SECTION 7.5.150 PARKING AREA DESIGN:

It is also not exactly clear if Jordan Cove's proposed workforce housing mancamps would be exactly like their proposed North Point workforce mancamps complete with eating establishments and convenience centers.

Section 4.3.210 – CATEGORIES and review standards

The following categories provide a definition and specific standards that will regulate the Development, Use or Activity identified in the table above.

* * * *

(28) Eating and Drinking Establishments or Restaurant facilities – this category includes bakery, cafe, catering service facility, confectionery, delicatessen, food truck, tavern, lounge and coffee shop.

(a) ***This use shall comply with the compatibility standard found in Section 4.3.220****;*
(b) ***Meet parking and access requirements of Chapter VII; and***
(c) ***Obtain any necessary health license****.*

There is no indication that Jordan Cove has met these requirements. In addition, even though Jordan Cove is providing a temporary workforce housing complex, housing and rent prices in the Coos Bay Area would most definitely go up as they have done in other areas where these projects have been proposed. (***See Exhibit 49 to 51***) Increases in crime and impacts to medical and health facilities also has not been considered. Just like in those areas, the local Unions here have stated subsistence pay for workers that would be similar to those mentioned in the attached news stories that ended up driving up rent and housing prices and driving local tenants out. ***(See Exhibit 52***) This would put an extreme hardship on local established citizens.

Where would the rest of these thousands of projected workers that have been projected by Jordan Cove (6,000 to 8,500 noted above) and their families live?

Right now people in the trades here are hard pressed to be able to keep up. The International Brotherhood of Electrical Workers is ALREADY calling people out of retirement in the electrical trades and THIS PRIOR to any Jordan Cove project coming to town. We are currently pressed for affordable housing in this area also. Jordan Cove's proposed Park-n-Rides won't even come close to providing the parking that would be needed for their projected construction workers?

TEMPORARY DREDGE TRANSPORT LINES

JCEP proposes to construct two temporary dredge lines. JCEP proposes to construct the first temporary dredge line in the 6-WD and 7-D zones. This temporary dredge line will transport dredged material from JCEP‘s dredging in the slip and access channel to a disposal site in South Dunes. Applicant‘s Exhibit 2 shows the location of this dredge line. JCEP proposes to construct the second temporary dredge line in the 13B-NA and 14-DA zones. This temporary dredge line will transport dredged material from the Coos Bay Deep Draft Navigation Channel, which JCEP seeks approval to widen in a separate pending application, to the Kentuck Mitigation Site.

The Staff Report states:

> ***The applicant has provided details on the project but <u>staff was not able to locate an impact assessment,</u> however, they stated they will be compatible with resource capabilities of this area. The dredge line is temporary but <u>the applicant should explain how they will ensure these inventoried resources will be protected</u> or if impacts to the habitat how it will be mitigated. This may have been done through other permitting agencies and the applicant should provide the permits. This also may be addressed in the Draft Environmental Impact Statement and if it is then the applicant should provide the applicable section***

Requirements spelled out in CBEMP Policy 5a, 17 and 18 must be followed including resource impacts assessments. Jordan Cove has failed to provide those.

Mitigation Insufficient / Temporary Dredge Pipeline would impact Eelgrass and other habitat areas.

Jordan Cove‘s proposed dredging and temporary pipeline would impact eelgrass areas in the lower Coos Bay and natural aquatic areas in the 7-NA and 13B-NA zones. It would also impact zoning districts 6-DA and 14-DA. Jordan Cove has yet to prove a need for their dredging project that outweighs the negative impacts to fishing, recreation and navigation. They have provided no plans to mitigate habitat areas and marine life that would be destroyed in the lower bay by their proposed dredging plans. Jordan Cove‘s proposed eelgrass mitigation site also lacks sufficient proof that it would be successful and not harm other already productive eelgrass areas.

A March 2019 letter by the Shon Schooler, Ph.D., Research Coordinator with the South Slough National Estuarine Research Reserve states: (***See Exhibit 10***)

> *We are particularly concerned with the potential impacts to eelgrass (Zostera marina) populations as eelgrass is an important habitat for many estuarine species and improves estuarine water quality. The following comments fit under CBEMP Policy 4: Resource Capability Consistency and Impact Assessment. Eelgrass habitat in the Coos Estuary has experienced a net loss since 2005 (from mapping/GIS methods) and abundance has declined more recently since 2016 (from intertidal field surveys).*

Below find maps of eelgrass areas found in the lower bay in 2005:

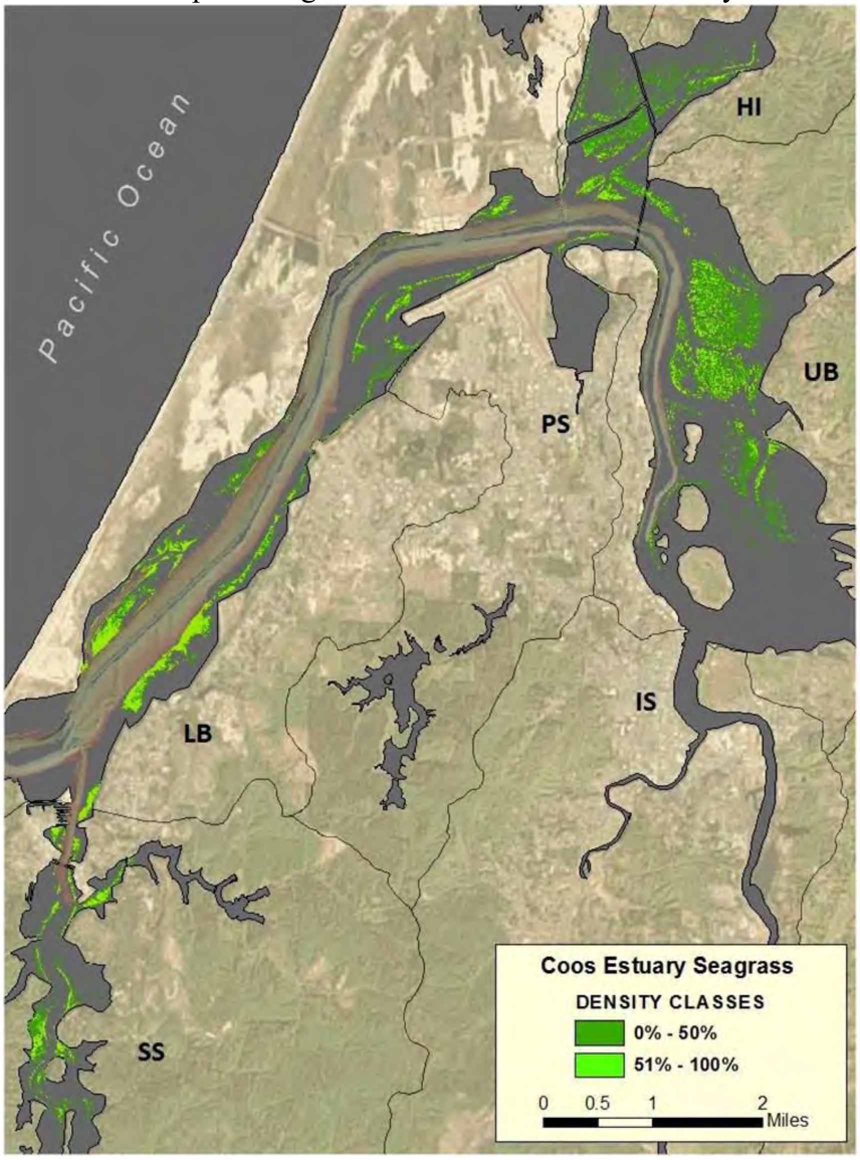
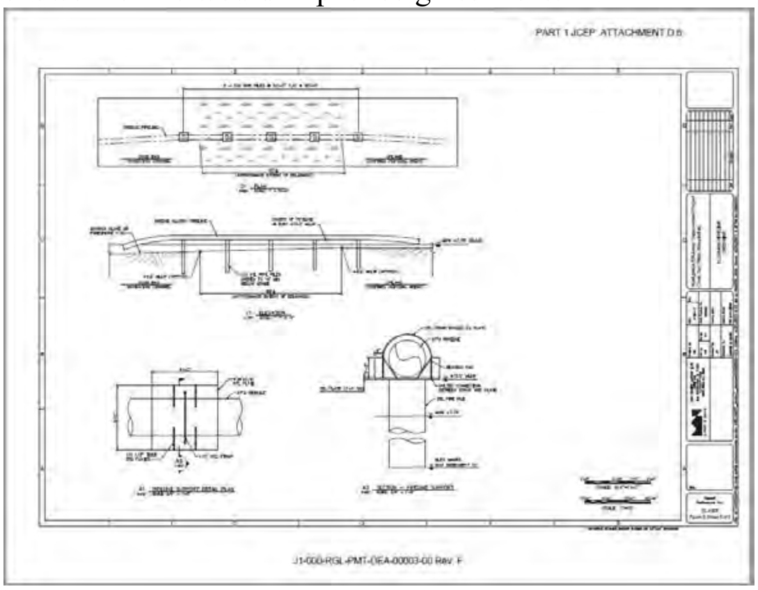


Figure 1 above: Distribution of seagrass beds (green) and location of deep water in the shipping channel (tan). Dense beds (> 50% ground cover from seagrasses) are shown in light green. Seagrass data generated from aerial photos taken in 2005. Data: Clinton et al. 2007, NGDC 2014

Jordan Cove's proposed temporary dredge pipeline would transit through most of the lower bay. It is unknown how much restriction this would cause to other bay users or how secure this line would be against the vast tidal action of the lower bay. **This temporary pipeline activity is only permitted subject to Policy #5a noted above**. The temporary pipeline must be consistent with the resource capabilities of the area (see CBEMP Policy #4) and must also satisfy the impact minimization criterion of Policy #5. The affected areas are to be restored to their previous condition. Jordan Cove is not asking for an exemption for the impact their temporary pipeline alteration would have on the estuary and **they have yet to provide the necessary evidence that they have met the CBEMP requirements**. Jordan Cove's proposed dredging, eelgrass mitigation site, and temporary pipeline would directly impact known eelgrass areas in the Coos Bay. No evidence has been provided as to how these impacted areas would be successfully restored after being impacted. In addition, Jordan Cove's 2007 Coos Bay Estuary Mitigation permit has long since expired. (CBDC **17.130.140**) and it is unclear if they will be able to obtain another new permit.

Dredge Transfer Line diagram below is from page Page 460 of Jordan Cove's DSL Application and shows the line would impact eelgrass areas.



Jordan Cove's proposed temporary dredge transfer line support structures are slated to sit on current known eelgrass bed areas. There is no indication how stable this transfer line would be with the swiftness of the tides in our area nor is there any mitigation being proposed for the negative impacts this temporary line would have on eelgrass and other habitat areas that **<u>are to be protected</u>** in zoning district 7-NA. 13B-NA, 6-DA and 14-DA zones.

100 FOOT HIGH VAPOR FENCES CREATE ADDITIONAL HAZARDS

Safety measures incorporated in the proposed Jordan Cove LNG terminal actually increase the chance of a catastrophic failure and present a far more serious public safety hazard than regulators have analyzed and deemed acceptable.[13] Jerry Havens, Distinguished Professor of Chemical Engineering at University of Arkansas, and James Venart, Professor Emeritus of Mechanical Engineering at University of New Brunswick, have asked specific questions to the FERC concerning these hazard issues.[14] Those questions need to be addressed properly. This would impact potential future industry and the Ports proposed Oregon Gateway cargo terminal to the East of the proposed LNG facility, which would not be allowed to operate in these hazard areas. (***See Exhibits 76 and** 77*)

[13] January 14, 2015 Report filed by Jerry Havens Ph.D and James Venart Ph.D. to FERC concerning *discrepancies and problems with Jordan Cove Energy Project hazard analysis* under CP13-483 et. al. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150114-5038

[14] Feb 6, 2014 Follow-up Report/ *Questions concerning discrepancies and problems with Jordan Cove's hazard analysis* under CP13-483 et al. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150206-5040

PROPOSED FIRE STATION WOULD BE LOCATED IN LNG HAZARDOUS BURN ZONE

According to the staff report:

> *JCEP proposes to construct a fire station in the 6-WD zone. The use is a standalone fire department building within the access and utility corridor that JCEP has established for the LNG Terminal site. JCEP initially proposed to co-locate this use with the SORSC in the IND zone. JCEP now proposes to relocate the fire station proposal from the IND zone to the 6-WD zone. Exhibit 2 shows the location JCEP proposes for the fire station. Splitting the fire station from the SORSC and relocating it will improve emergency incident response time. Fire water storage tanks will be located and stored adjacent to and used by the fire station. The fire department will house Jordan Cove Fire Department chief and staff. The LNG Terminal will provide electric power for operation of the fire department building.*

CCZLDO Section 4.3.210 – CATEGORIES and review standards

> *The following categories provide a definition and specific standards that will regulate the Development, Use or Activity identified in the table above.*
>
> *(1) Accessory structures and uses – shall be subordinate to any authorized primary use. Accessory structures* ***<u>shall meet the applicable Development and Siting Criteria or Special Development Considerations and Overlays for the zoning district in which the structure will be sited.</u>***
> * * * *
> *(30) Emergency services – This category includes correctional institution, jail, penal farm, fire stations, police stations, emergency service training facilities (which may include firearms training), emergency preparedness centers, storage caches and standby power generating equipment for Essential Facilities. If a conditional use is required as indicated on the zoning table* ***<u>it shall comply with the compatibility standard found in Section 4.3.220</u>***.

It makes no sense whatsoever nor is it compatible to place a fire station in the LNG hazardous burn zone area. On June 3, 2016, Sightline researcher Tarika Powell did a follow-up report on the explosion that occurred on March 31, 2014 at a much smaller liquefied natural gas (LNG) peak shaving plant in eastern Washington. That explosion **forced hundreds to evacuate their homes within a two mile radius of the facility, injured five workers, and caused $69 million in damages**.

Powell's 2016 Sightline article[15] states that the Washington Department of Labor and Industries (Washington L&I), which had conducted an investigation into the safety of employees at the Plymouth plant, found that Williams endangered its employees, lacked an adequate emergency response plan, and had deficient safety training. The company's track record—not just in the Northwest, but throughout the US—revealed a pattern of failures to heed safety regulations. (***See Exhibit*** *77*) This illustrates why our regulatory agencies should not underestimate the fire and explosion hazards of natural gas processing plants such as the proposed Jordan Cove LNG Export Facility.

[15] https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/

In addition, according to Professor Havens, computer modeling used to predict the Jordan Cove Energy Project (JCEP) LNG export terminal vapor cloud explosion hazards **have not been approved** for predicting explosion overpressures by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). Havens expressed concerns to both the FERC and to the PHMSA that the Government is failing to adequately provide for the risks of potentially devastating Unconfined Vapor Cloud Explosions (UVCEs) of heavier-than-methane hydrocarbons at the proposed Jordan Cove Export Terminal site. **Those hazards appear to be seriously underestimated. (*See Exhibit 76*)**

> *The new Draft Environmental Impact Statement (DEIS) for the Jordan Cove Export Terminal, just issued,* ***continues to seriously underestimate vapor cloud explosion overpressures (damage) that could occur following credible releases of heavy hydrocarbons at the JCET site****. The latest predictions that I am aware of appear to be an order of magnitude lower than are indicated by physical evidence of numerous documented UVCEs that have occurred worldwide with the potential to cause injuries and deaths to persons and result in destruction of the facility.*
> Jerry Havens, PhD, April 1, 2019 (Emphasis added)

While the FLACS Model used by JCEP designed to predict dispersion has been approved by the PHMSA, the FLACS Model used by JCEP designed to predict vapor cloud explosion overpressures has **not been approved** for such use. The FLACS-Fire Model used by JCEP to calculate fire radiation intensity to ensure that the prescribed radiation limits do not extend beyond the property values **has also not received such approval**. (***See Exhibit 76***)

This may be considered an accessory use to the LNG facility but in reality is a necessary use that should be located out of the hazardous burn zone areas of the proposed facility.

PROPOSED HELIPAD

The location of Jordan Cove's proposed Helipad is not clear and it is also unclear as to whether this Helipad complies with the zoning requirements for being located in the airport overlay of the Southwest Oregon Regional Airport. There is no indication that the Oregon Aeronautics Division has approved the Helipad.

Section 4.3.210 – CATEGORIES and review standards

> *The following categories provide a definition and specific standards that will regulate the Development, Use or Activity identified in the table above.*
>
> *(1) Accessory structures and uses – shall be subordinate to any authorized primary use.* ***Accessory structures shall meet the applicable Development and Siting Criteria or Special Development Considerations and Overlays for the zoning district in which the structure will be sited.***
> *   *   *   *
> *(7) Airport/Heliport (Personal and Public)*
> *(a) Public Airports need to be either located in the Airport Operations (AO) zone or show a need to be located in an area to serve the community.*
> *(b) Personal-use airports for airplanes and helicopter pads, including associated hangar, maintenance and service facilities. A personal use airport as used in this section means an*

airstrip restricted, except for aircraft emergencies, to use by the owner, and on an infrequent and occasional basis, by invited guests, and by commercial aviation activities in connection with agricultural operations. ***No aircraft may be based on a personal-use airport other than those owned or controlled by the owner of the airstrip***. ***Exceptions to the activities permitted under this definition may be granted through waiver action by the Oregon Aeronautics Division in specific instances***. *A personal-use airport lawfully existing as of September 13, 1975, shall continue to be permitted subject to any applicable rules of the Oregon Aeronautics Division*
(Emphasis added)

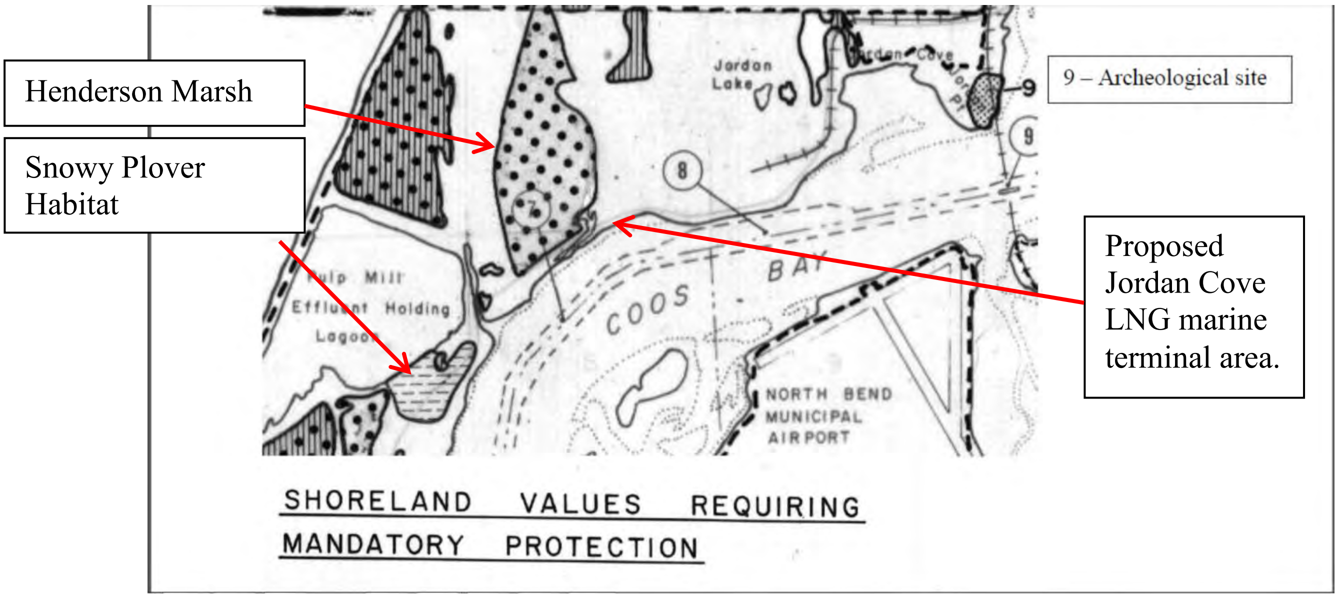
SOUTH DUNES SITE FENCE CONSTRUCTION*:*

The applicant would discharge approximately five cubic yards of concrete fill within a wetland to form structural supports for the construction of perimeter fence at their South Dunes Site. The fence would measure eight feet tall and approximately 3,688-feet in length and would be located along the eastern extent of the South Dunes site.

This appears to be a take-over of these Coastal Shoreland areas. Fencing could harm recreational activities that occur in this area and it makes no sense whatsoever for Jordan Cove to be fencing in a wetland. ? Below find a recent picture of Kayakers using this area along the shoreland for recreational activities.

This fenced in area is also a known and protected archeological site area as indicated in the Shoreland Values Map section that has been copied and pasted below:

COOS COUNTY SHORELAND VALUES REQUIRING MANDATORY PROTECTION:



COOS BAY ESTUARY OVERVIEW AND IMPACTS

The Coos Bay Estuary is the sixth largest estuary on the Pacific coast of the contiguous United States and the largest estuary completely within Oregon state lines. The Coos estuary is one of only 28 National Estuarine Research Reserves in the United States.[16] The process for federal designation of a National Estuarine Research Reserve has many steps and involves many individuals and organizations. Established by the Coastal Zone Management Act of 1972, as amended, the reserve system is a partnership program between the National Oceanic and Atmospheric Administration and the coastal states. The Coastal Zone Management Act of 1972, as Amended, is clear:
§ 1452. Congressional declaration of policy (Section 303) states:

The Congress finds and declares that it is the national policy--

1) **to preserve, protect**, develop, **and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations**; (Emphasis added)

2) to encourage and assist the states to exercise effectively their responsibilities in the coastal zone through the development and implementation of management programs to achieve wise use of the land and water resources of the coastal zone, **giving full consideration to ecological, cultural, historic, and esthetic values** as well as the needs for compatible economic development, which programs should at least provide for-- (Emphasis added)

   2(A) **the protection of natural resources, including wetlands, floodplains, estuaries, beaches, dunes, barrier islands, coral reefs, and fish and wildlife and their habitat, within the coastal zone**, (Emphasis added)

   2(B) the management of coastal development to minimize the loss of life and property caused

[16] National Estuarine Research Reserve System (NERRS): http://estuaries.noaa.gov/About/Default.aspx?ID=116

by improper development in flood-prone, storm surge, geological hazard, and erosion-prone areas and in areas likely to be affected by or vulnerable to sea level rise, land subsidence, and saltwater intrusion, and by the destruction of natural protective features such as beaches, dunes, wetlands, and barrier islands,

2(C) the management of coastal development to improve, safeguard, and restore the quality of coastal waters, and to protect natural resources and existing uses of those waters.

These laws as well as many others also listed in this act need to be fully considered and evaluated in with this Permit Application. The law demands protection and public access to the coastal areas for recreation purposes and assistance in the redevelopment of deteriorating urban waterfronts and ports, and sensitive preservation and restoration of historic, cultural, and esthetic coastal features.

Oregon's Statewide Planning GOAL 16 (OAR 660-015-0010(1))[17] requires Oregon:

To recognize and protect the unique environmental, economic, and social values of each estuary and associated wetlands; and

To protect, maintain, where appropriate develop, and where appropriate restore the long -term environmental, economic, and social values, diversity and benefits of Oregon's estuaries…

*… Estuary plans and activities **shall protect the estuarine ecosystem**, including its natural biological productivity, habitat, diversity, unique features and water quality.*

The general priorities (from highest to lowest) for management and use of estuarine resources as implemented through the management unit designation and permissible use requirements listed below shall be:

1. Uses which maintain the integrity of the estuarine ecosystem;
2. Water-dependent uses requiring estuarine location, as consistent with the overall Oregon Estuary Classification;
3. Water-related uses which do not degrade or reduce the natural estuarine resources and values;
4. Nondependent, nonrelated uses which do not alter, reduce or degrade estuarine resources and values

* * * *

IMPLEMENTATION REQUIREMENTS
*…2. Dredging and/or filling **shall be allowed only**: a. If required for navigation or other water-dependent uses that require an estuarine location or if specifically allowed by the applicable management unit requirements of this goal; and, b. **If a need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights**; and c. If no feasible alternative upland locations exist; and, d. If **adverse impacts are minimized**. Other uses and activities which could alter the estuary shall only be allowed if the requirements in (b), (c), and (d) are met. All or portions of these requirements may be applied*

[17] http://www.oregon.gov/LCD/docs/goals/goal16.pdf

at the time of plan development for actions identified in the plan. Otherwise, they shall be applied at the time of permit review.

3. State and federal agencies shall review, revise, and implement their plans, actions, and management authorities to maintain water quality and minimize man-induced sedimentation in estuaries. ***<u>Local government shall recognize these authorities in managing lands rather than developing new or duplicatory management techniques or controls</u>****. Existing programs which shall be utilized include:*

a. The Oregon Forest Practices Act and Administrative Rules, for forest lands as defined in ORS
527.610-527.730 and 527.990 and the Forest Lands Goal;
b. The programs of the Soil and Water Conservation Commission and local districts and the Soil Conservation Service, for Agricultural Lands Goal;
c. The nonpoint source discharge water quality program administered by the Department of
Environmental Quality under Section 208 of the Federal Water Quality Act as amended in 1972 (PL92-500); and
d. ***<u>The Fill and Removal Permit Program administered by the Division of State Lands under ORS 541.605 -541.665</u>****.*

4. The State Water Policy Review Board, assisted by the staff of the Oregon Department of Water Resources, and the Oregon Department of Fish and Wildlife, the Oregon Department of Environmental Quality, the Division of State Lands, and the U.S. Geological Survey, shall consider establishing minimum fresh-water flow rates and standards so that resources and uses of the estuary, ***<u>including navigation, fish and wildlife characteristics, and recreation, will be maintained</u>****.*
(Emphases added)
[Oregon GOAL 16: Estuarine Resources pages 1 and 2.]

Coos Bay consists of about 14,000 acres of varied intertidal and subtidal substrate habitat conditions including algae beds, eelgrass sites, marshlands, and mostly unconsolidated substrate. The upper Coos Bay estuarine habitat contains important rearing habitat supplied by estuarine wetlands, algae, and eelgrass beds, which are important conditions for estuarine fish and migratory salmon, as well as commercial oyster beds.

Estuaries are the most important and dynamic habitat type known on earth; where fresh and saline waters mix, creating natural resource biomass far exceeding all others. Recent signs show improvement or biological recuperation of the Coos Bay estuary. Notwithstanding this important healing process, **the LNG (Jordan Cove facility and Pacific Connector Pipeline) development would reverse this biological recovery and cause irreplaceable and irretrievable ecosystem change.**

1. NEPA Process / Environmental Impact Statement (EIS) must be completed first

Full impacts to all potentially affected waterbodies and impacted species connected to those waterbodies in Coos, Douglas, Jackson and Klamath Counties <u>should be analyzed by a third party independent analyst</u> in a properly completed NEPA process and Environmental Impact Statement long before any additional decisions are made with respect to the proposed project or before any potential approval is given to the project. Alternatives to the Project <u>do exist</u> and those alternatives are not being considered in this application process.[18]

The construction and operation of the Jordan Cove LNG export terminal and the Pacific Connector Gas Pipeline are entirely dependent on the issuance of an Order for authorization and *Certificate of Public Convenience and Necessity* under sections 3 and 7 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Federal Energy Regulatory Commission‗s (FERC) regulation. Under existing law, FERC is required to document its decision-making process leading to the issuance **<u>or non-issuance</u>** of the FERC Certificate via an Environmental Impact Statement (EIS) prepared in conformance with National Environmental Policy Act (NEPA) regulations.

The EIS is to ―*provide full and fair discussion of significant environmental impacts and shall <u>inform decisionmakers and the public</u> of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment*" (40 CFR 1502.1) ―***<u>Agencies shall not commit resources prejudicing selection of alternatives before making a final decision</u>***" (40 CFR 1502.2(f)) (Emphasis added)

The EIS should "*serve practically as **<u>an important contribution</u>** to the decision-making process and **<u>will not be used</u>** to rationalize or justify decisions already made*." (40 CFR 1502.5) (Emphasis added) An EIS, in and of itself, is not a decision document. Rather, <u>after</u> public review and comment, it is followed up by a formal record of decision (ROD) which documents how and why one of the alternatives analyzed in the EIS was selected for implementation.

By processing land use applications prior to the completion of the EIS process, Coos County is committing agency resources for a preferred LNG terminal siting location and pipeline route alternative prior to the final alternative selection by the FERC. Coos County would essentially be approving a terminal and pipeline design that may **<u>or may not</u>** be the best alternative. The failure to limit the actions of the applicant prior to the completion of the EIS process as called for in existing regulations, clearly demonstrates that Coos County‗s view of the EIS is not as a critical part of the decision process, but rather as a disclosure and justification document relating to a decision that has already been made. This posture is a direct violation of both the letter and intent of the NEPA.

How can the FERC ―*have the exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal*" [15 U.S. Code § 717b(e)(1)] if the Jordan Cove and Pacific Connector project are allowed to process permits for one of the preferred alternatives?

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[18] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20170710-5423:
026FERC_Exb20_Braddocks_Power Point Slide #17 to NWPPA.PDF
026FERC_Exb21_Weyerhaeuser_Hunting_Map.PDF
026FERC_Exb22_Alternative_PCGP_Route_Ver1_Weyco.PDF
026FERC_Exb23_Alternative_PCGP_Route_Ver2_Weyco.PDF
026FERC_Exb24_Alternative_PCGP_Route_Ver3_Weyco.PDF
026FERC_Exb25_Alternative_PCGP_Route_Ver4_SoOre.PDF
026FERC_Exb26_Alternative_JCEP_PCGP_Route_Ver5.PDF
026FERC_Exb27_AlternativeJCEPSitingLocation_Ver6.PDF

The fact that these land use applications for Coastal Zone Management Act permits and approvals are being processed at this time in advance of Jordan Cove/Pacific Connector FERC publication of a Final EIS tends to lend credence to the following assumptions:

- The Jordan Cove/Pacific Connector applicant, by spending the time, effort, and funding to pursue these Federal, State and County permits in advance of the EIS, apparently fully believes the FERC EIS process, will result in the issuance of the federal permit. Thus, Jordan Cove fully expects that the EIS will be simply the justification of a pre-conceived action rather than an objective and un-biased analysis of all reasonable alternatives as explicitly called for in existing Federal regulations.

- FERC, Coos County, Army Corps, DEQ and DSL, by allowing the processing of these various Federal/State/County permit applications at this time, is demonstrating that it essentially concurs with this violation of the NEPA process.

How can Oregonians be expected to fully participate in the NEPA process by objectively evaluating the range of alternatives that would be provided in a valid EIS if, in fact, Oregon state and county agencies have already issued permits and certifications for one of the alternatives beforehand?

2. Oysters, Clams, Crabs and Fish would be negatively impacted by the Jordan Cove/Pacific Connector Project

The Coos Bay is the largest commercial producer of shellfish in the state of Oregon. Jordan Cove would dredge and excavate approximately 5.7 million cubic yards (mcy) of material to create the slip basin and access channel in an area currently known as Ingram Yard. It is well known that Ingram Yard contains toxic materials from past industrial activities that were buried out there long ago. **Appropriate environmental reviews need to be done on the Ingram Yard property**. The property has been filled over many years with material dredged from a bay surrounded by heavy industries, and the property was used by Menasha and then Weyerhaeuser for many years before strict contamination controls were required. In July of 1999, Nucor Corporation withdrew from purchasing 575 acres of land on the North Spit from Weyerhaeuser. Nucor purportedly backed out because Weyerhaeuser insisted on transferring all potential liability for past contamination of the property to the buyer.

Despite multiple requests, Jordan Cove continues to ignore these concerns and has yet to properly test the soils in Ingram Yard where toxic compounds are likely to be found. (***See Exhibits 5 and 6***) **Contaminates in the tidal muds of the project area have also not been fully evaluated for past industrial contaminates which are highly likely to be re-mobilized during dredging activities.** This would make the already poor water quality conditions of the Coos Estuary even worse.

Both Clausen Oysters[19] and Coos Bay Oyster Company[20] (***See Exhibit 7***) have expressed concerns in the past about the potential for turbidity and loss of their commercial oysters from Jordan Cove's dredging activities. Commercial oysters would be at risk as well as populations of Olympia oysters

[19] FERC Motion to Intervene Out-of-Time of Clausen Oysters and Lilli Clausen, as in individual and owner, under CP13-483, et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20141015-5087
[20] FERC Motion to Intervene and update Contact Information of Coos Bay Oyster Company / Jack Hampel under CP13-483, et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150302-5065

which are protected and not harvested. Page 13 of Jordan Cove's Oct 2017, 404 Application states under item #4 that ―*...dredging associated with the navigation reliability improvements and eelgrass mitigation site, will be performed during the ODFW in water work window (October 1 to February 15)*." Electronic page 123 of Jordan Cove's DSL application ALSO states the same thing (See Page 28 of David Evans and Associates Technical Memorandum). **October is the height of the Olympia oyster reproductive cycle[21] and would mean that Olympia oyster spat would be at risk of massive die-off** should dredging occur during this time.

Eelgrass can also be adversely affected by turbidity because the depth and distribution of eelgrass is strongly associated with water clarity and depth of light penetration (Dennison and Orth 1993; Thom et al. 1998) as well as nutrient availability (Short et al. 1995), salinity, and water temperatures (Thom et al. 2003). The proposed marine slip and access channel would result in the permanent loss of 14.5-acres of shallow subtidal and intertidal habitat, 0.06-acre of estuarine saltmarsh habitat and approximately 1.9-acres of submerged aquatic vegetation habitat (eelgrass). **This would affect baby salmon and other marine organisms that depend on these ecosystems remaining intact.**

The Oregon DEQ's Integrated Report identifies the Coos Bay Estuary status as Category 5, water quality limited, 303(d) list (in CWA), and Total Maximum Daily Load (TMDL) is needed due to elevated fecal coliform measurements. (ODEQ 2012d).[22] This is also the case for several of the tributaries and rivers that are upstream of the Coos Estuary.

The Clam Diggers Association of Oregon have already found high levels of contaminants in clams coming from the Coos Bay [23] (***See Exhibit 8***) and Commercial oysters are currently not always able to be harvested due to elevated fecal coliform measurements within the Coos Bay.

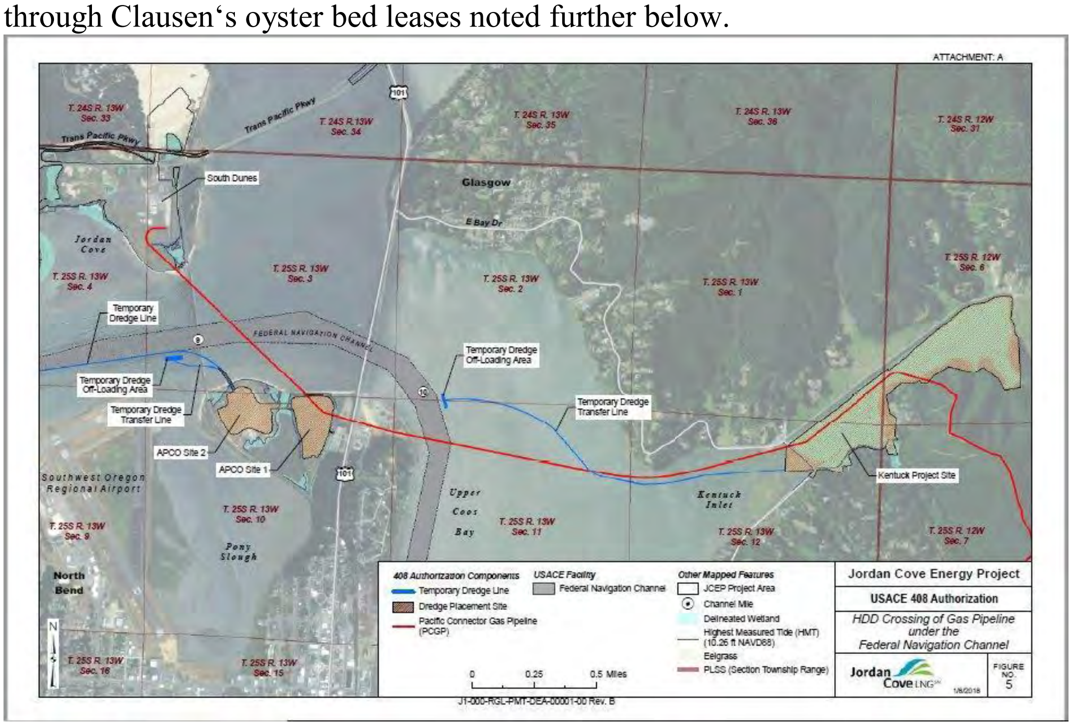
Dredging on the scale that is being proposed by Jordan Cove and the Port of Coos Bay has the potential to significantly affect both marine habitat and the amount and velocity of water flowing in and out of Coos Bay during the tidal cycle. All these increased impacts need to be evaluated due to their potential to significantly degrade these waters.

Currently the Pacific Connector is proposing to do an HDD through the Coos Estuary. Previously the Williams Pipeline company, who had a 50% interest in the Pacific Connector, also wanted to do an HDD that went under a much smaller section of the Coos Estuary. Williams did multiple tests and found the soils in the Estuary, particularly those below 35 feet, to be too unstable to do an HDD. It is rather suspect that now Pembina thinks that an even larger and more risky HDD in the Coos Estuary would be viable. There needs to be a third party investigation into these critical matters as the 12-inch pipeline that was built in 2003/2004 had dozens of frack-outs that severely contaminated tributaries in the Coos Watershed with drilling muds.

[21] ―*Settlement Preference and the Timing of Settlement of the Olympia Oyster, Ostrea Lurida, In Coos Bay, Oregon*", by Kristina M. Sawyer, A Thesis, Presented to the Department of Biology and the Graduate School of the University of Oregon in partial fulfillment of the requirements for the degree of Master of Science, September 2011.
[22] https://www.deq.state.or.us/wq/assessment/rpt2012/results303d12.asp
[23] Motion to Intervene Out-of-Time Clam Diggers Association of Oregon under CP13-483., et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20140221-5118

The photos above are frack-outs that occurred with the Coos County pipeline built in 2003/2004.

The diagram below is from Jordan Cove's May 10, 2018 filing (Part 1) with the FERC in response to staff data request dated Apr 20, 2018. This diagram was filed as part of Jordan Cove's 60% Design Package for their Section 408 Review.[24] It shows a temporary dredge transfer line that will also go through Clausen's oyster bed leases noted further below.



The diagram below is found in PCGP's May 24, 2018 filing to the FERC and shows a little more detail than what is found in other PCGP maps. These particular map pages show the PCGP HDD in relation to Clausen oyster bed leases in the Coos Bay estuary.[25]

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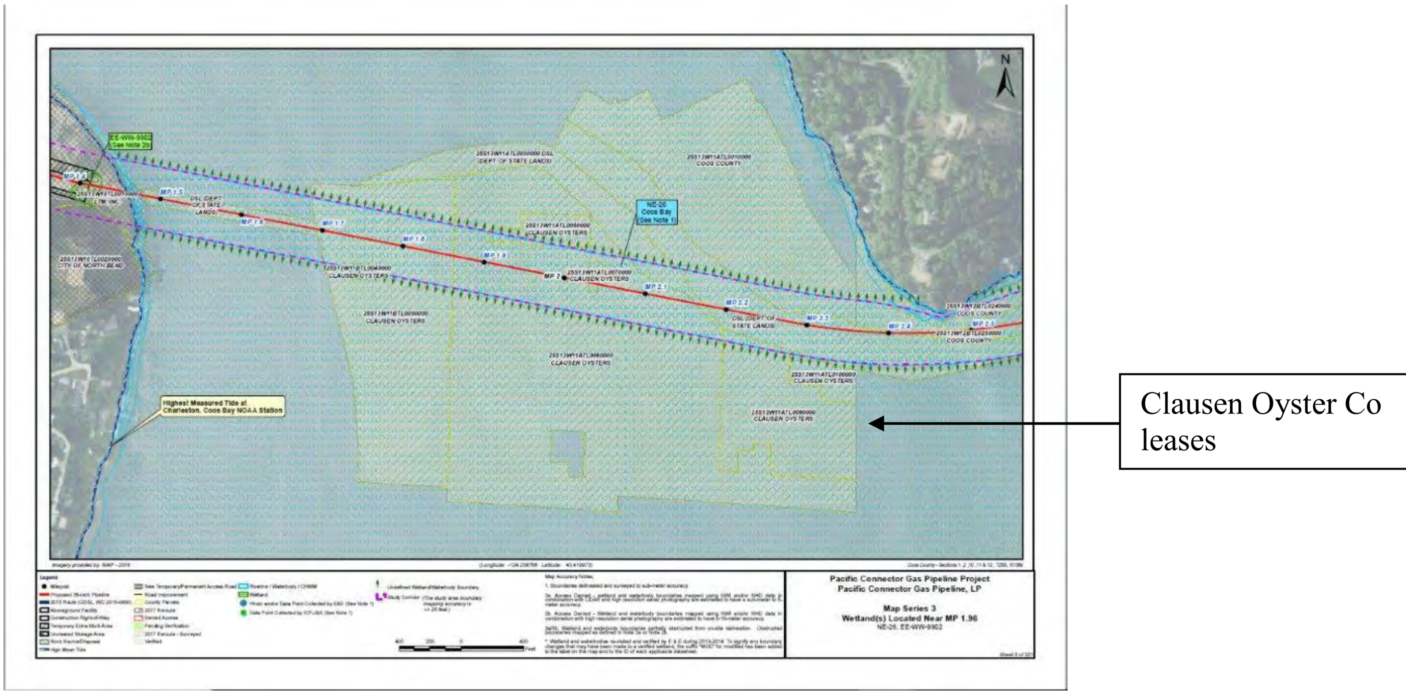
[24] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180510-5165
[25] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180524-5118



It is doubtful that the Clausen oyster company even knows what exactly is being proposed or how it could negatively impact their oyster beds.

Sylvia Yamada, a marine ecologist who has studied native crabs and the European green crab in Oregon and Washington for over 20 years, submitted comments into the DSL record where she stated the following: (***See Exhibit 9***)

> *…Not only will the turbidity during the construction phase be of concern to the ecological community, the on-going dredging to maintain the berth and shipping channels will continue be a disturbance to the ecosystem. It will result in habitat loss for native species, including the valuable Dungeness crab. In one study between 45 to 85 % of the Dungeness crabs died during a simulated dredging operation (Chang and Levings, 1978). Marine habitat modification by construction of the Jordan Cove Energy Project could impact the important Oregon Dungeness fishery.*[26]

Dr. Mark Chernaik succinctly summarizes the issues in the following statement found on page 9 of this November 14, 2011 Coos County Surrebuttal report under File No. HBCU-10-01/REM-10-01:

> *Proponents of multi-billion dollar industrial projects have vast resources to pay for scientific reports with elaborate illustrations that have the allure of scientific validity. Because citizens who are concerned about the impacts of such projects must make do with far fewer resources, these project proponents are not accustomed to close inspection of their technical data, assumptions, reasoning and conclusions. This imbalance describes the situation between PCGP and CALNG and the question of whether the proposed project would fail to protect the resource productivity of Haynes Inlet.*

[26] Comments of Sylvia B Yamada, Ph.D. in FERC Docket for Jordan Cove – PF-17-4 ;http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20170622-0008

~~"~~Despite the David-versus-Goliath situation they find themselves in, CALNG has revealed numerous, serious flaws in the technical arguments put forward by PCGP, including the early claim by Dr. Bob Ellis that Olympia oysters ~~"~~are not known to inhabit the Project Action Area (ODLCD, 1998)." LUBA Record at page 1331. Following this, CALNG has revealed additional errors, including but not limited to the following errors that are the subject of this round of testimony: that PCGP relied on untrained surveyors to identify and find native oysters in Haynes Inlet; that PCGP misunderstands the nature of native oyster restoration experiments performed by Dr. Danielle Zacherl; and that PCGP relied on un-validated estimates of background turbidity and inaccurate assumptions of sediment particle size when predicting the impact of trenching activities.[6] Combined with previous errors, such as proposing to commence trenching activities at the beginning of October, just before the height of the spawning season for Olympia oysters in Coos Bay, these numerous mistakes place the applicant far short of meeting their burden of demonstrating that their proposed project would not have more than a de minimis or insignificant impact on native oysters in Haynes Inlet."[27]

We hope that the Coos County Commissioners will consider and address these issues, along with others presented here in this filing during their review and analysis of the Jordan Cove LNG Export project. Dredging impacts should **not have more than a *de minimis* or insignificant impact on commercially raised and native oysters in the Coos Estuary**. Conditions of Approval **should be imposed** on the project in order to protect and insure the vitality of the Olympia oyster (*Ostrea lurida*) and other functioning biological systems within the estuary.

3. Environmental contamination on the Jordan Cove property is not fully being evaluated and considered

A December 16, 2014 letter from Barbara Gimlin,[28] (***See Exhibits 5 & 6)*** former Environmental Lead for the Jordan Cove project, addressed to Jeff C. Wright, Director, Office of Energy Projects, at the Federal Energy Regulatory Commission, exposes the fact that the Ingram yard site is contaminated and proper environmental studies are not being done on the property. In March 2014, Barbara had been named as the acting Environmental Inspector (EI) for the JCEP Kiewit $15 million exploratory test program conducted at the LNG terminal site on the North Spit of Coos Bay. Work done by Jordan Cove at the Ingram yard site during 2014 under DEQ's, *~~"~~General NPDES 1200-C Permit for Construction Storm Water Discharges for Pile Test and Ground Improvement Testing Programs,*" involved clearing done on the property, road building and other work that was extensive and clearly impacted the current ecological environment at the Ingram Yard site. A video clip of contamination that leached into the nearby Henderson Marsh was noted during this time: http://citizensagainstlng.com/wp/wp-content/uploads/2014/12/Henderson-Marsh-on-North-Spit-5-18-2014-MVI_6925.mov

The Ingram Yard property where the Jordan Cove Project is being proposed contains dredging spoils that were dumped there many years ago. **When DEQ proposed a "*No Further Action*" letter for the site they made it clear that there were residual contaminants in the dredge spoils on the land**

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[27] November 14, 2011: Mark Chernaik, Ph.D., Surrebuttal Report; Page 9 under Coos County File No. HBCU-10-01/*REM-10-01*

[28] Comment of Barbara J Gimlin under CP07-444, on Jordan Cove Energy Project, L.P., Draft Environmental Impact Statement; FERC/EIS-0223F ; LNG Terminal Facility. Concerns about site contamination issues. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20141218-5020

surface, and that it was inappropriate for the material to be placed in waters of the state, and inappropriate to be disposed elsewhere in an unrestricted fashion. If it ever comes to the point where they are actually dredging the material, DEQ will have a roll in approving/disapproving the ultimate fate of where the excavated sediments go. As part of that approval process, DEQ will want to know about the quality of the sediments and where they are planning to put them. **There was no testing as to the deeper levels of residual contaminants by DEQ** that I am aware of.

CONTAMINATED SOILS WOULD NOT BE A PROPER USE AS FILL FOR THE LNG STORAGE TANKS OR THE POWER PLANT OR THE GAS PROCESSING FACILITY OR THE TRANSPACIFIC PARKWAY REALIGNMENT. These soils are likely to leach contamination into the Bay thus harming marine life and the bay's biological function. WHERE IS THE OVERSIGHT AND ENFORCEMENT THAT WOULD PROTECT THE BAY since it obviously did not occur during the stormwater permitting process? Empty promises by the applicant are no longer good enough.

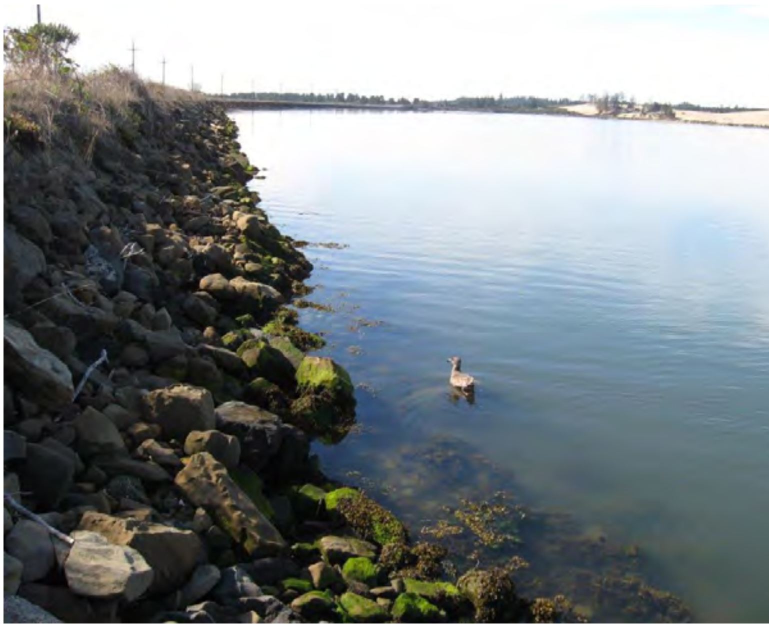
4. Tidal soil contaminant testing is absent and/or not adequate

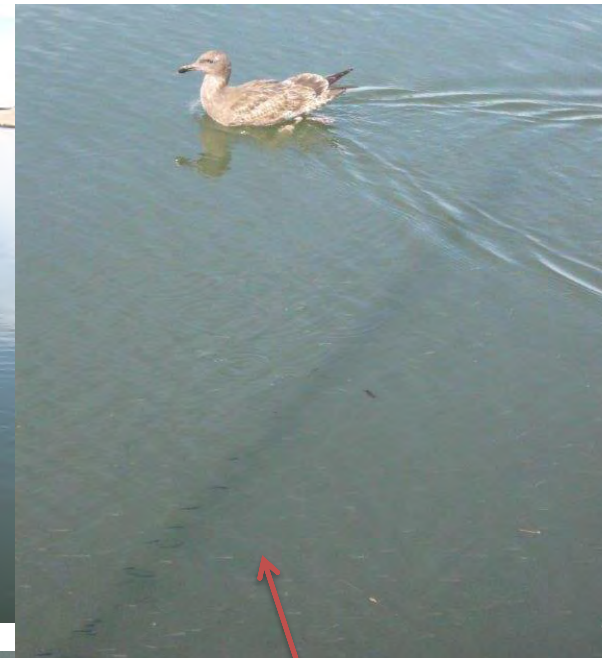
Jordan Cove's DSL application on electronic page 1015 states, —*The chemical analytical data from the Corps FNC indicate that chemicals of concern present near the project area generally include metals, phenols, various phthalates and PAHs*." The Roseburg Chip facility berth was tested in 2009 and TBT was detected above the SL1 in the west part of the berth; discrete re-sampling did not detect TBT but dredging was restricted to the eastern portion of the berth anyway. Past shipping contaminants including Tributyltin (TBT), arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs) **could be re-suspended into the Coos Bay** harming marine life and businesses that depend on that marine life. (***See Exhibit 12***) Tidal muds need to be tested prior to any Coos County approval and Jordan Cove's sedimentation plan MUST CONTAIN TESTING FOR ALL POTENTIAL CONTAMINANTS AND CURRENTLY DOESN'T. (See electronic page 524 of Jordan Cove's DSL application, Table 9-2)

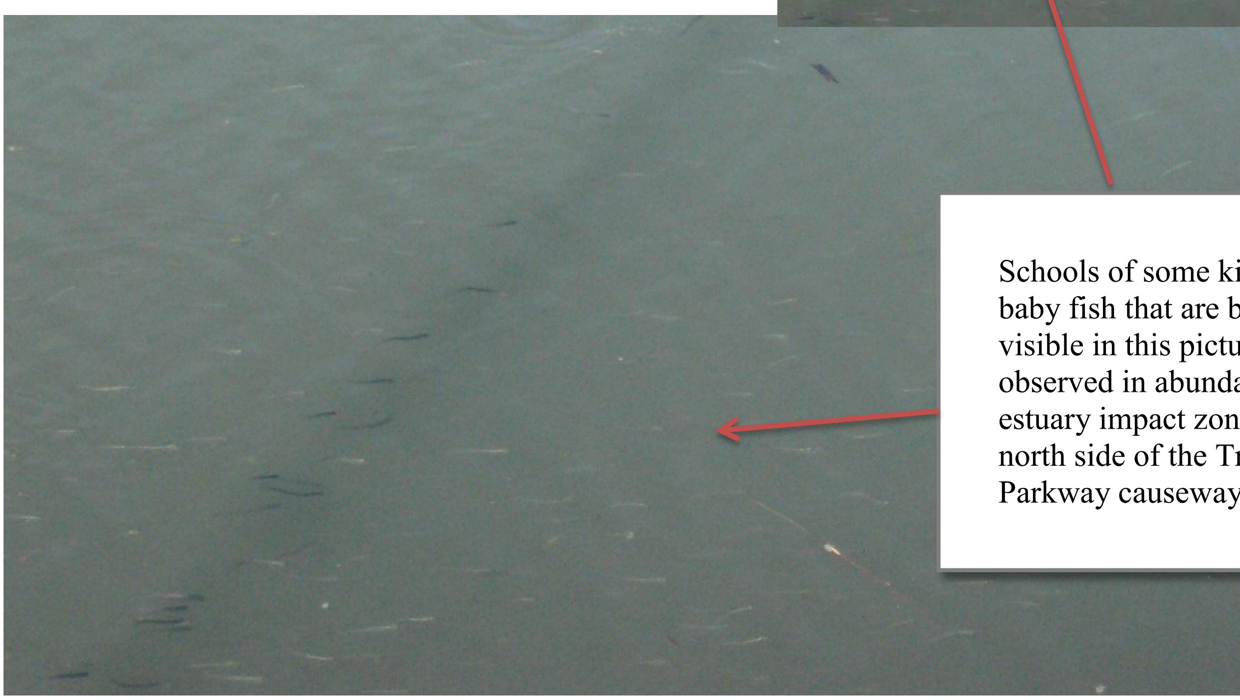
The cumulative damage to the Coos Bay Estuary from the proposed JCEP project would be significant due to the extensive dredging, ballast water, invasive species and water quality impacts.[29] **This would violate the Coastal Zone Management Act [30] and the Estuary Restoration Act of 2000** [31]

The Coos Estuary to the North of Jordan Cove's transportation to the site, their proposed Transpacific Parkway widening impact area is teaming with wildlife. A report from 1979 confirms this fact. (***See Exhibit 10)*** The photo below is looking towards the West on the North Side of the Transpacific Parkway where the additional lane project is proposed.

[29] The proposed Jordan Cove LNG Export Project would dredge 5.7 million cubic yards of dredge material in order to build their LNG marine slip dock and another .6 mcy of dredging in the Coos Bay for a total of 6.3 million cubic yards of material. The Port of Coos Bay has plans for an extensive deepening and widening of the shipping channel in the lower Coos Bay and removal of 18 mcy. This amounts to 24.3 million cubic yards of material in total. Ballast water, invasive species and water quality impacts from the project would be significant.
[30] The Coastal Zone Management Act. http://coast.noaa.gov/czm/act/?redirect=301ocm
[31] The Estuary Restoration Act: http://www.era.noaa.gov/information/act.html





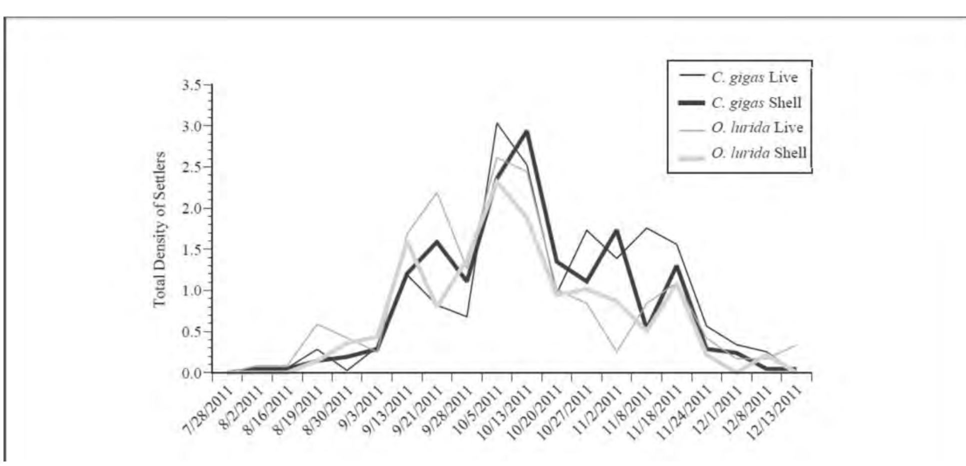


Schools of some kind of baby fish that are barely visible in this picture were observed in abundance in the estuary impact zone on the north side of the Transpacific Parkway causeway.

Fish bones and bird excrement show that ecosystems exist in the rocky shoreline areas of the impact zone.

South of the utility power pole on the south side of the TPP impact area, commercial oyster beds are observed in abundance. Turbidity and sedimentation impacts on the North side of the Transpacific Parkway in the 10A-NA zoning district would also impact the 13A-NA zoning district on the South side due to tidal influence.

—*Settlement Preference and the Timing of Settlement of the Olympia oyster, Ostrea Lurida, in Coos Bay, Oregon"* by Kristina M. Sawyer (A Thesis) September 2011 found the height of the Olympia oyster reproductive cycle to occur in or around the month of October. (See Digram from the Sawyer report below.) High sedimentation in the water is deadly for both Olympia oyster spat and also Commerical Pacific oysters that are farmed in the area. Large amounts of seditmentation can cause a high rate of fouling and oyster death. Any contaminated soils coming from the Ingram yard property would not be apropriate in this area. **Fill is not an allowed use in the 10-NA zone.**



The Environmental Analysis should include a section known as the Affected Environment
The EIS should contain an analysis of what the current conditions of our ecosystems are right now, along with how this project would impact those current biological compromised systems as a whole.

ESTUARY ISSUES OF CONCERN THAT NEED TO BE FULLY ADDRESSED

- Loss of habitat for fish, crabs, clams oysters and other marine and wildlife.

- Loss of vital eelgrass beds (this is supposedly to be mitigated, but State Agencies in the past have expressed series doubts about the adequacy of the planned mitigation)

- Possible erosion issues caused from the massive dredging and ship and tug wakes.

- The use of riprap and the altering of the bay‘s water velocity and flow.

- Sediment transport issues that can occur when channels are deepened. Tidal amplification and hyper concentrated sediment conditions can occur in the upstream tidal rivers. Channel deepening may increase up-estuary suspended sediment transport due to enhanced salinity-induced estuarine circulation and have a large impact on increasing suspended sediment concentration (SSC)[32]

- Risk of destabilizing Henderson Marsh wetlands and the North Spit due to the excessive dredging.

- Potential negative impacts to wetland areas including habitat and vegetation.

- Potential negative impacts to the nearby floodplains.

- Potential negative impacts to adjacent wildlife and people. What effect will dredging have on adjacent shorelands? Snowy Plover habitat? Clam beds? Other marine and wildlife? People? Shoreland structures? Rising water levels due to climate change?

- An increase in the Tsunami hazard zone areas due to an increase in amount of water and water velocity that will be in the bay due to the increased dredging.

- Interference with Traditional Activities on the Lower Bay (Fishing, Crabbing, Boating, Recreation, etc) including economic impacts to businesses associated with these activities.

- The potential for increased flooding upstream of the Kentuck Inlet.

[32] *The impact of channel deepening and dredging on estuarine sediment concentration* D.S.van Maren, T.van Kessel, K.Cronin, L.Sittoni ; Continental Shelf Research Volume 95, 1 March 2015, Pages 1-14

ENDANGERED SPECIES IMPACTS

The Project is not in compliance with Regulations for protecting threatened and endangered species including Army Corps Standard Local Operating Procedures for Endangered Species (SLOPES).

According to the former FERC September 2015 Jordan Cove FEIS page 5-15 to 5-16:

> The Project is ***likely to adversely affect***:
> the proposed threatened fisher (west coast DPS);
> the threatened MAMU;
> the threatened NSO;
> the threatened green sturgeon (Southern DPS);
> the threatened Pacific eulachon (Southern DPS);
> the threatened coho salmon (SONCC);
> the threatened coho salmon (Oregon Coast ESU);
> the endangered Lost River sucker;
> the endangered shortnose sucker;
> the threatened vernal pool fairy shrimp;
> the endangered Applegate's milk-vetch;
> the endangered Gentner's fritillary;
> the endangered large-flowered meadowfoam; and
> the threatened Kincaid's lupine.

This list is not complete, however. For example, Jordan Cove Resource Report #3, dated September 2017, page 100 states:[33]

> ***3.4.1.6 Plants***
> *Five federally- and state-listed plant species have the potential to occur in the JCEP Project Area. The western lily is the only federally-listed species. State-listed species include the pink sand verbena, Point Reyes bird's-beak, silvery phacelia, western lily, and Wolf's evening primrose. The only state-listed species detected within the vicinity of the JCEP Project Area was Point Reyes bird's beak.*

Jordan Cove's September 2017 Resource Report #3, May 2013 *Botanical Resources Assessment Report* page 23 states:

> *Based on the current location of development at the site, a small area of potential* ***habitat for Point Reyes bird's-beak will be removed.*** ***No state regulation applies to this species, because the project is on private property and this species is not federally listed***.[34] (Emphasis added)

[33] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20170921-5142
[34] June 2017 RR#3 May 2013 *Botanical Resources Assessment Report* - Jordan Cove Energy Project Coos County, Oregon by SHN Consulting Engineers & Geologists, Inc.; Page 23 of report

The actual listing of this plant is as follows:

Point Reyes bird's-beak

- **Species Common Name** Point Reyes Bird's-beak
- **Species Scientific Name** *Cordylanthus maritimus ssp. palustris*
- **Federal Listing Status** Species of Concern
- **State Listing Status** Endangered

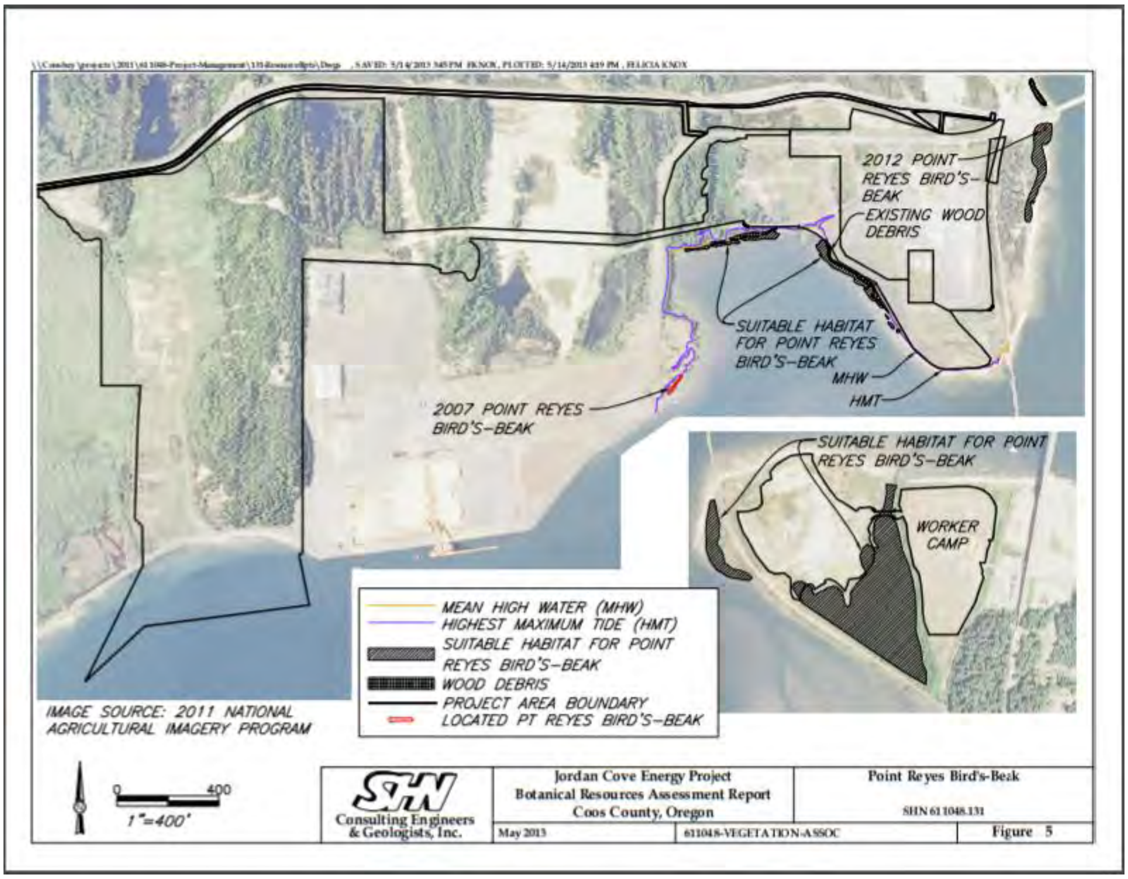
Jordan Cove Resource Report #3, dated September 2017, page 101 states:[35]

> ***3.4.1.6.3 Point Reyes Bird's-Beak (Federal Species of Concern, State Endangered)***
>
> *Point Reyes bird's-beak (Chloropyron maritimum ssp. Palustre, formerly Cordylanthus maritimus ssp. palustris) is an annual gray-green and purple-tinged herb that grows 4 to 16 inches tall and has few branched stems. Point Reyes bird's-beak inhabits the upper end of maritime salt marshes, and its habitat requirements are specific: approximately 7.5 to 8.5 feet above mean lower low water, sandy soils with soil salinity of 34 to 55 parts per thousand, and less than 30% bare soil in summer (Appendix D.3). It flowers from June to October. Associate species include those that are tolerant of high salinity levels such as salt grass, pickleweed, fleshy jaumea (Jaumea carnosa), sea lavender, and dodder (Cuscuta salina). Point Reyes bird's-beak occurs along the Pacific Coast from Tillamook County, Oregon, south to Santa Clara County, California. In Oregon, the species is restricted to Netarts Bay, Yaquina Bay, and Coos Bay, with the majority of known occurrences located in Coos Bay.*
>
> *Populations with 1,000 to 10,000 plants are located along the margins of Coos Bay and on sand salt marshes near the edge of high water marks (ORBIC 2017).* ***Several occurrences of Point Reyes bird's-beak are located in the vicinity of the JCEP Project Area (ORBIC 2017; Appendix D.3), as shown in Figure 3.4-4****. This species is known to occur within the intertidal wetland between APCO Sites 1 and 2. There is no suitable habitat on APCO Site 2 at the dredge disposal access point; this area is dominated by upland vegetation. This species also occurs outside the JCEP Project Area along the west and southeast shoreline of the South Dunes site (ORBIC 2017). Potential habitat for this species has also been observed along the shoreline south of the SouthDunes site. This habitat contains an abundance of the associated species, including pickleweed. Prior to construction, an additional survey for Point Reyes bird's-beak will be conducted during the appropriate blooming period in the area defined as potential habitat for the species.*
> (Emphasis added)

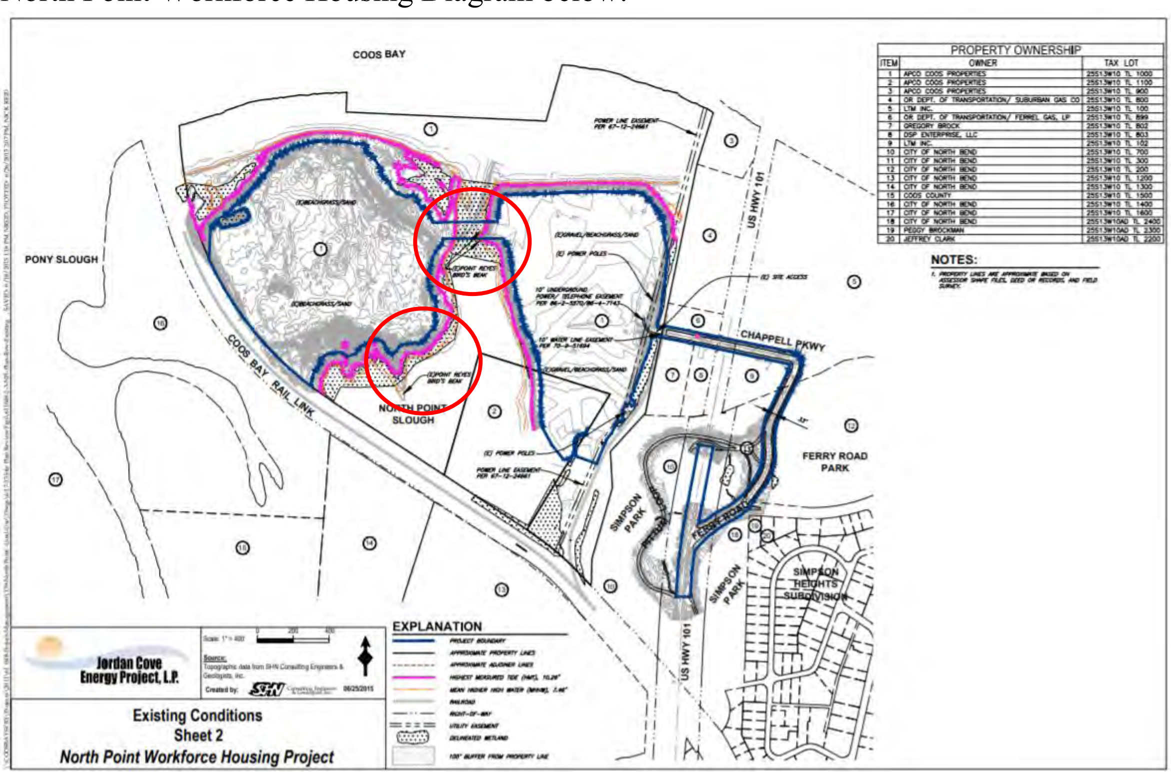
WHERE IS THE PROTECTION OF THIS OREGON ENDANGERED PLANT?

Jordan Cove's Figure 3.4-4 has been filed as privileged with the FERC but Jordan Cove's other drawings do not show all the areas where Point Reyes bird's beak has been located as indicated when comparing what is found in their current Resource Report #3 (below) to an earlier diagram from their former North Point Workforce Housing proposal (second diagram below).

[35] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20170921-5142



Areas noted above would be suitable for Point Reyes Birds Beak <u>because the plant is already located there.</u> Note the red circled areas below showing where plants were found in the former Jordan Cove North Point Workforce Housing Diagram below:



This is just one significant plant that should be protected but is being overlooked. Waiting until construction is ready to begin before dealing with this plant species is not sufficient. **How many more plant and animal species are also being overlooked like this?** Jordan Cove's dredge placement sites will clearly negatively impact the Oregon Endangered Point Reyes bird's-beak and possibly other plant and animal life as well.

OAR 141-122-0020 Policies

> *(13)* ***The Department will not grant an easement if the proposed use or development is inconsistent with any endangered species management plan adopted by the Department under the Oregon Endangered Species Act*** *(ORS 496.171 to 496.192).*

The State of Oregon has listed the following plants in Coos County as being endangered:
Abronia umbellata var. *breviflora* - Pink sandverbena - Endangered
Cordylanthus maritimus ssp. *palustris* - Point Reyes bird's-beak - Endangered
Lilium occidentale - Western lily - Endangered
Phacelia argentea - Silvery phacelia – Threatened

There is no indication that surveys were done for any of these plant species. Point Reyes bird's-beak is a federal species of concern, is listed endangered by the State of Oregon, and is a Bureau Sensitive species. Historically, this annual, hemi-parasitic herb occurred along a 900 mile section of coastline, from Netarts Bay, Oregon, south to Morrow Bay, California. Today, it is known only from Netarts Bay, Yaquina Bay, and Coos Bay. The primary threat to the Point Reyes bird's-beak is habitat loss from development, OHVs, and water pollution from petroleum spills. **(*See Exhibit 13*)**

ORS 196.805 [36] Policy

> *(1)* ***The protection, conservation and best use of the water resources of this state are matters of the utmost public concern****. Streams, lakes, bays, estuaries and other bodies of water in this state, including not only water and materials for domestic, agricultural and industrial use but also* ***habitats and spawning areas for fish, avenues for transportation and sites for commerce and public recreation, are vital to the economy and well-being of this state and its people****. Unregulated removal of material from the beds and banks of the waters of this state may create hazards to the health, safety and welfare of the people of this state. Unregulated filling in the waters of this state for any purpose, may result in interfering with or injuring public navigation, fishery and recreational uses of the waters. In order to provide for the best possible use of the water resources of this state, it is desirable to centralize authority in the Director of the Department of State Lands, and implement control of the removal of material from the beds and banks or filling of the waters of this state.*
>
> *(2)* ***The director shall take into consideration all beneficial uses of water including streambank protection when administering fill and removal statutes.***
>
> *(3) There shall be no condemnation, inverse condemnation, other taking, or confiscating of property under ORS 196.600 to 196.905 without due process of law. [Formerly 541.610 and then 196.675; 2003 c.738 §16; 2012 c.108 §7]*
>
> (Emphasis added)

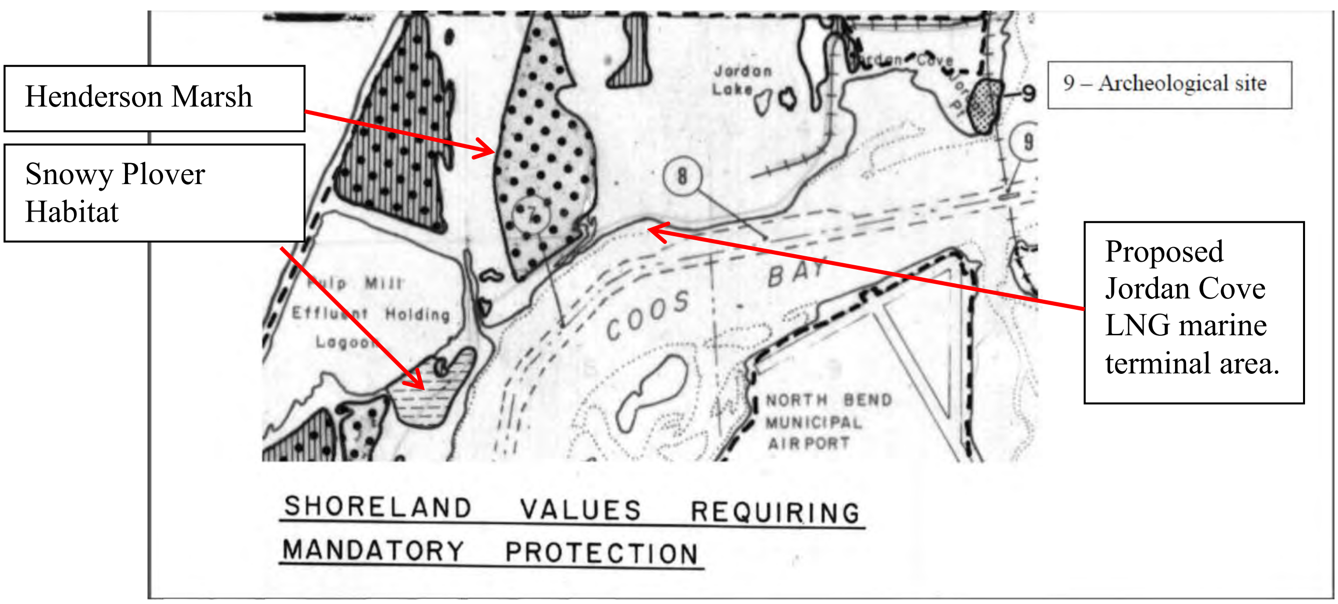
[36] http://www.oregonlaws.org/ors/196.805

Abalone

Southern Oregon is on the northern edge of red abalone range and the state's fishery is managed conservatively to protect the health of Oregon's relatively small population. Abalone are highly prized and the fishery creates a high demand, primarily among divers. While seven species exist on the West Coast, **five of these have some listing status under the Endangered Species Act**.[37] Red abalone are the only species still fished in the contiguous United States, and southern Oregon and northern California are the only areas where recreational harvest has occurred in recent years. Commercial harvest is not allowed in either state. Currently Oregon has postponed the 2018 recreational season that was set to open on Jan. 1 until further review and Commission consideration.

SHORELAND VALUES REQUIRING MANDATORY PROTECTION

The following shows the Coos County Shoreland Values Map Requiring Mandatory Protection under the Coos Bay Estuary Management Plan:



Conditions of Approval found in Coos County File No.'s HBCU-07-03; HBCU-07-04; and REM-09-02 of HBCU-07-04 call for protection of wetland areas including Henderson Marsh which is a high value habitat area. (***See Exhibits 14, 15 and 16***) Critical species, including Snowy Plovers, would be harmed by the Jordan Cove facility's loss of habitat areas, noise impacts and operations, including those coming from Jordan Cove's proposed gas flaring.
Gas flares and noise are always more intense than what the industry claims they would be during permitting. These impacts would have negative

[37] https://www.dfw.state.or.us/news/2017/12_dec/122817.asp

impacts on Snowy Plovers and other habitat, including many other shorebirds that currently nest in the Henderson Marsh wetland area. In 2013 about 7,500 songbirds, possibly including some endangered species, were killed while flying over a flare at a gas plant in Saint John. (***See Exhibit 17***) Photo above and to the right is of a gas flaring event at the Corrib plant in 2016. Residents found the event to be ‗frightening.' (***See Exhibit 18***)

AGENCY BIOLOGICAL OPINION HAS NOT BEEN RELEASED

Below find excerpts from the 2011 Army Corp / NMFS Consultation:

Endangered Species Act Section 7 Formal Programmatic Opinion, Letter of Concurrence
and
Magnuson-Stevens Fishery Conservation and Management Act Essential Fish Habitat Conservation Recommendations

Revisions to Standard Local Operating Procedures for Endangered Species to Administer Actions Authorized or Carried Out by the U.S. Army Corps of Engineers in Oregon
(SLOPES IV In-water Over-water Structures)
NMFS Consultation Number: 2011/05585
Federal Action Agency: Army Corps of Engineers,
Portland District, Operations and Regulatory Branches

GLOSSARY

For this consultation –
* * * *

Fill *means any material that has been placed below the plane of the ordinary high water mark or the high tide line.*
* * * *

Listed species *means any species of fish, wildlife, or plant which has been determined to be endangered or threatened under section 4 of the Federal Endangered Species Act.*
* * * *

Riparian management area *means land: (1) Within 150 feet of any natural water occupied by listed species during any part of the year or designated or proposed as critical habitat; (2) within 100 feet of any natural water within 1/4 mile upstream from areas occupied by listed species or designated as critical habitat and that is physically connected by an above-ground channel system such that water, sediment, or woody material delivered to such waters will eventually be delivered to water occupied by listed salmon or designated as critical habitat; and (3) within 50 feet of any natural water upstream from areas occupied by listed species or designated as critical habitat and that is physically connected by an above-ground channel system such that water, sediment, or woody material delivered to such waters will eventually be delivered to water occupied by listed salmon or designated as critical habitat.*
* * * *

1.3 Proposed Action
* * * *

The Corps is proposing to use this iteration of SLOPES to authorize four categories of actions, specifically:
*** * * ***

Maintain, rehabilitate, replace, or remove an existing in-water or over-water

structure *as necessary to extend the useful service life of the structure, or to withdraw the public or private structure from service when its usefulness has ended. Eligible structures include, but are not limited to, an aid to navigation, boat house, boat launch ramp, breakwater, buoy, commercial/industrial/recreational pier or wharf, port/industrial/marina facilities,*[1] *covered boat house, dock, dolphin, float plane hanger, floating storage unit, floating walkway, groin, jetty, marina, mooring structure, permanently moored floating vessel, private boat dock, recreational boat ramp, or wharf.*

This does not include any action that would occur in a Superfund Site designated by the U.S. Environmental Protection Agency, a state-designated clean-up area, or the likely impact zone of a significant contaminant source, as identified by historical information or the Corps' best professional judgment.

* * * *

1.3.1. Proposed Design Criteria

The Corps proposes to apply the following design criteria, in relevant part, to every action authorized or carried out under the program and approved under this opinion. Measures described under ―Administration" apply to the Corps as it manages the SLOPES program. Measures described under ―General Construction" apply, in relevant part, to each action that involves a construction component. Measures described under ―Types of Actions" apply, in relevant part, to each action as described.

* * * *

1.3.1.2 General Construction

* * * *

14.Compensatory mitigation*. Any action that will permanently displace riparian or aquatic habitats or otherwise prevent development of properly functioning condition of natural habitat processes will require compensatory mitigation to* ***fully offset those impacts****.* (Emphasis added)

a. Examples of actions requiring compensatory mitigation include construction of a new or enlarged boat ramp or float, the addition of scour protection to a boat ramp, or construction of new impervious surfaces without adequate stormwater treatment.

* * * *

d. As part of NMFS's review under clause 3 above, NMFS will determine if the proposed compensatory mitigation fully offsets permanent displacement of riparian or aquatic habitats and/or impacts that prevent development of properly functioning processes.

* * * *

16. Site preparation. *During site preparation, conserve native materials for restoration, including large wood, vegetation, topsoil and channel materials (gravel, cobble and boulders) displaced by construction. Whenever practical, leave native materials where they are found and in areas to be cleared, clip vegetation at ground level to retain root mass and encourage reestablishment of native vegetation.* ***Building and related structures may not be constructed inside the riparian management area****.* (Emphasis added)

The Jordan Cove project is NOT in compliance with Army Corps Standard Local Operating Procedures for Endangered Species (SLOPES) requirements. Jordan Cove does not comply with the Army Corps SLOPES program, particularly since their proposed building and related structures would be constructed inside the 150 foot riparian management area that is supposed to be protected due to the Coos Estuary containing threatened species of Oregon Coast Coho salmon, Southern Green Sturgeon (Acipenser medirostris) and Eulachon (Thaleichthys pacificus). Jordan Cove's Pacific Connector trenching and horizontal directional drill (HDD) structures near other impacted waterbodies likely affect several other ESA listed species as well.

[1] This includes replacing existing pilings, fender piles, group pilings, walers, and fender pads. It also includes the installation of new mooring dolphins and structural pilings, height extension of existing pilings and the relocation of floats within an existing marina.

DREDGING/FILL NOT IN COMPLIANCE WITH LAND USE

Jordan Cove Energy Project (JCEP) plans to remove 5.7 million cubic yards of material for their proposed marine terminal and access channel and also has plans to excavate four submerged areas lying adjacent to the federally-authorized Channel along with an area for eel grass mitigation. According to Jordan Cove this will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window.

Two of the areas that Jordan Cove wants to dredge in the Coos Estuary are zoned ―Natural Aquatic,” one is zoned ―Conservation Aquatic,” two are zoned ―Developmental Aquatic.” One area where they want to place fill is zoned ―Natural Aquatic” (***See Exhibit 19***) Most of these zoning districts DO NOT ALLOW NEW DREDGING except in zoning district 3-DA (Developmental Aquatic) and where the LNG marine terminal is being proposed (zoning district 6-DA), but even then, dredging is **only allowed** in those Developmental Aquatic zoning districts subject to Administrative Conditional Use – Special Conditions and General Conditions.

Chart below covers zoning issues within the Coos Bay Estuary itself (Does not include Coastal Shorelands and/or wetland areas that would also be affected.)

Jordan Cove Terminal Components	Estuary Zoning District affected	New Dredging	Fill	Land Use Status
Marine Slip and Access Channel 5.7 mcy total	6-DA and 5-DA	Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions	Fill - Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions Dredged material disposal - Not allowed	Pending – Under current Coos County Remand proceeding. REM-19-001
Channel Dredge Area 1	59-CA	Not allowed	Not allowed	Pending - Coos County Land use Hearing date: March 8, 2019 AM-18-011/RZ-18-007/HBCU-18-003
Channel Dredge Area 2	2-NA	Not allowed	Not allowed	Pending – Coos County Land use Hearing date: March 8, 2019 AM-18-011/RZ-18-007/HBCU-

				18-003
Channel Dredge Area 3	3-DA	Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions	Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions	Pending – Coos County Land use Hearing date: March 8, 2019 AM-18-011/RZ-18-007/HBCU-18-003
Channel Dredge Area 4	52-NA	New dredging shall be allowed only to dredge a small channel on the north side of the proposed airport fill as necessary to maintain tidal currents. In addition, this activity is only allowed subject to a finding that adverse impacts have been minimized (see Policy #5).	Not allowed	Pending – City of Coos Bay Application Hearing date: March 21, 2019 187-18-000153-PLNG-01
Transpacific Parkway (―TPP")/US 101 Intersection Widening	10-NA	Not allowed	Fill - Not allowed. Dredged material disposal - Not allowed.	Pending - Coos County Land use Hearing date: Feb 1, 2019. (Re Previous Land use process - Hearing Officer recommended denial.)

This means Jordan Cove will need to change the zoning (if that is even possible) in some of these Estuarine zoning districts to even be able to dredge or to place fill. Both the Coos County Planning and the City of Coos Bay are currently processing applications and in some cases setting up for additional hearings. **That is not right!!**

And how is it that Jordan Cove is even taking out land use permits for the Estuary when they are not the legal owner of the Coos Estuary?

Other Jordan Cove / Pacific Connector Land Use Permit Processes still in Limbo

- Coos County file Nos. AM-18-009, AM-18-010 and AM-18-011 for Jordan Cove / Pacific Connector Transpacific Parkway widening, PCGP Earlyworks route and CB Channel Navigation alterations are currently waiting for the Hearing Officer's recommendation.

- Coos County file No. AM-18-010/HBCU-18-002 (Pacific Connector Early Works HDD Route in Estuary/Coastal Shoreland/Forest/EFU Zones) – Pending – Record closed – Waiting for HO recommendation.

- City of North Bend File No. FP 2-18 And CBE 3-18 (Pipeline under Historic NB McCullough Bridge in M/H zone and Coastal Shoreland/Estuary Zone) – The City Council recently made a determination on this and that determination can be appealed to the Oregon LUBA.

- City of Coos Bay File No.187-18-000153-PLNG-01 (Channel Navigation Alteration / Temporary Dredge Transport Pipeline in City of Coos Bay Estuary Zones) - Pending - Coos Bay City Council process which is still underway.

- City of North Bend File No. FP 4-19 & CBE 5-19 (Temporary Dredge Transport Pipeline / Temporary Dredge Offloading Facility / Permanent Bridge and Support Structures / Approval for Disposal of Dredge Materials) The City Council recently made a determination on this and that determination can be appealed to the Oregon LUBA.

- Coos County File No. AP-19-002 Appeal of Coos County Planning approval of Extension Application for Blue Ridge Alternative Route under EXT-18-012. Initial BOC Order No. 14-09-062PL. Extension has been approved for one year.

- **Douglas County Pacific Connector Gas Pipeline Application Extension**. On January 23, 2019 the Pacific Connector Conditional Use Permit was nullified by Circuit Court Judge Kathleen Johnson who reversed the county's prior decisions to extend a conditional use permit for the pipeline proposed to be built on a 7-mile stretch in Douglas Counties Coastal Zone. Currently a new land use process is underway with the first round of comments due on Oct 18, 2019.

- **Conditions of Approval on several other land use permit applications that have been processed have yet to be completed or met so at the present time the Jordan Cove/Pacific Connector Project does NOT have final approved land use permits in the Coastal Zone.**

Any changes to the Coos Bay Estuary Management Plan (CBEMP) zoning districts or any impacts to the zoning districts <u>must be in compliance with the other resource preservation and protection policies established elsewhere in the CBEMP</u>. You cannot just pick and chose the sections you want to follow while ignoring everything else. That is not how the Plan is to be followed. The Resource productivity of the Coos Bay estuary must be maintained as established by Statewide Planning Goals 16, 17 and 18. Jordan Cove's proposed map amendment cannot throw out the resource protection requirements and other process requirements spelled out in the Goals. The CBEMP Policy 5 has requirements that specifically state they **<u>must be met before any exceptions to the Plan or Goals are allowed</u>**.

CBEMP 3.2 POLICY DEFINITIONS:

DREDGED MATERIAL DISPOSAL:

The deposition of dredged material in aquatic or upland areas. Methods of disposal include in-water disposal, beach and land disposal, and ocean disposal. In-Water Disposal is the deposition or dredged materials in a body of water. Ocean Disposal is the deposition or dredged materials in the ocean. Beach Disposal is the deposition of dredged materials in beachfront areas west of the foredunes. Land Disposal is the deposition of dredged materials landward of the line of non-aquatic vegetation, in ―upland” areas.

DREDGING:

The removal of sediment or other material from a stream, river, estuary or other aquatic area. Maintenance Dredging refers to dredging necessary to maintain functional depths in maintained channels, or adjacent to existing docks and related facilities; New Dredging refers to deepening either an existing authorized navigation channel or deepening a natural channel, or to create a marina or other dock facilities; Dredging to Maintain Dikes and Tide gates refers to dredging necessary to provide material for existing dikes and tide gates; Minor Dredging refers to small amounts of removal as necessary, for instance, for a boat ramp. Minor dredging may exceed 50 cubic yards, and therefore, require a permit.

CBEMP Policy 5 Estuarine Fill and Removal

I. Local government shall support dredge and/or fill ***only if such activities are allowed in the respective management unit, and****:*

a. The activity is required for navigation or other water-dependent use that require an estuarine location or in the case of fills for non-water-dependent uses, ***is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation****, as per ORS 541.625(4)*[38] *and an exception has been taken in this Plan to allow such fill;*

b. ***A need (ie., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights****;*

c. No feasible alternative upland locations exist; and

d. ***Adverse impacts are minimized.***

e. Effects may be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained;

f. The activity is consistent with the objectives of the Estuarine Resources Goal and with other requirements of state and federal law, specifically the conditions in ORS 541.615[39] *and Section 404 of the Federal Water Pollution Control Act (P.L.92-500).* (Emphasis added)

II. Other uses and activities which could alter the estuary shall only be allowed if the requirements in (b), (c), and (d) are met.

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[38] ORS 541.625 [1967 c.567 §5; 1969 c.593 §49; 1971 c.754 §5; 1973 c.330 §3; 1973 c.674 §6; 1977 c.417 §1; 1979 c.200 §1; 1979 c.564 §3a; 1981 c.796 §1; 1987 c.70 §1; 1989 c.837 §16; 1989 c.904 §70; renumbered 196.695 and then 196.825 in 1989]

[39] ORS 541.615 [1967 c.567 §3; 1971 c.754 §3; 1989 c.837 §15; renumbered 196.680 and then 196.810 in 1989]

<u>Identification and minimization of adverse impacts as required in "d" above shall follow the procedure set forth in Policy #4.</u> (Emphasis added)

As required by Goal #16, only dredging necessary for on-site maintenance of existing functional tidegates, associated drainage channels and bridge crossing support structures is permitted in Natural and Conservation Management Units (applies to 11-NA,18A-CA, 20-CA, 30-CA, 31-NA and 38-CA). Dredging necessary for the installation of new bridge crossing support structures is permitted in Conservation Management Units and may be allowed in Natural Management Units where consistent with the resource capabilities of the area and the purposes of the management unit.

In the Conservation Management Unit, new dredging for boat ramps and marinas, aquaculture requiring dredge or fill or other alteration of the estuary, and dredging necessary for mineral extraction may be allowed where consistent with the resource capabilities of the area and the purposes of the management unit.

*This strategy shall be implemented by the preparation of findings by local government documenting that such proposed actions are consistent with the Comprehensive Plan, and with the above criteria "a", "b", "c", "d", "e" and "f"; **<u>however, where goal exceptions are included within this Plan, the findings in the exception shall be sufficient to satisfy above criteria "a" through "d"</u>**. Identification and minimization of adverse impacts as required in "e" above **<u>shall follow the procedure set forth in Policy #4a</u>**. The findings shall be developed in response to a "request for comment" by the Division of State Lands (DSL), which shall seek local government's determination regarding the appropriateness of a permit to allow the proposed action.*

*"Significant" as used in "other significant reduction or degradation of natural estuarine values", shall be determined by: a) **<u>the U.S. Army Corps of Engineers through its Section 10.404 permit processes</u>**; or b) the Department of Environmental Quality (DEQ) for approvals of new aquatic log storage areas only; or c) the Department of Fish and Wildlife (ODFW) for new aquaculture proposals only.* (Emphasis added)

<u>This strategy recognizes that Goal #16 limits dredging, fill and other estuarine degradation in order to protect the integrity of the estuary.</u> (Emphasis added)

A need (ie., a substantial public benefit) has <u>not</u> been demonstrated by the applicant. The project would <u>unreasonably interfere with navigation, fishing and public recreation</u> and would therefore not be in compliance with CBEMP Policy 5(I)(b). This requirement must be met **<u>before an exception to the goals is allowed</u>**. Jordan Cove's proposed use/activity is not consistent with the resource capabilities of the management segment and no assessment of impacts required by CBEMP Policy #4 has been done. CBEMP Policy 5 is an important CBEMP Policy that applies to **<u>all Estuarine Fill and Removal</u>**. Policy 5 requires that ―a need (ie., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights." Policy 5 also requires that a determination be made that proves: d. Adverse impacts are minimized. **<u>These requirements must be demonstrated before an exception is allowed</u>**. **(OAR 660-004-0022)**

The applicant seems to think that all they need for an exception is the testimony of a Coos Bay Bar Pilot saying the channel modifications would improve shipping. At a recent public meeting that occurred on March 21, 2019, in Coos Bay, Captain George Wales from the Coos Bay Pilots Association made the statement that there are roughly 5 vessel calls per month on the Port of Coos Bay. The Port of Coos Bay's Annual Report for 2017 indicates around there were around 8 calls in 2017.[40] The real reason for the current request is spelled out in Captain Wales' letter filed by the applicant in with their Coos Bay application under Coos Bay File No.187-18-000153-PLNG-01 and their Coos County Application under File No. AM-18-011 in which he states, ―*The Pilots believe the proposed NRI's are essential for achieving the* ***required number of LNG vessel transits needed*** *to lift the JCEP design annual LNG production volume. JCEP has informed the Pilots that excessive delays in LNG Carrier transits to and from the LNG terminal could result in a shore storage tank topping situation…*" (Emphasis added) The Planning Staff Report states on page 2, ―*[t]his dredging will allow for vessel transit under a broader weather window* ***to enable JCEP to export the full capacity*** *from JCEP's liquefied natural gas (―LNG") terminal on the nearby North Spit*." (Emphasis added) So this is **ALL about what is best for Jordan Cove and not what is best for other users or uses of the Coos Bay Estuary**. Jordan Cove has agreements with the Roseburg Forest Products Company to use some of their property on the North Spit for an undisclosed amount of $$. It must be considerable considering the extreme hazards the LNG project presents to this chip facility and their 17 or so employees.[41] On the other hand a 2008 study by the Oregon State Marine Board (OSMB), found that recreational boaters in Coos Bay took a total of 31,560 boat trips the previous year. Nearly 90 percent of the boat use days involved fishing. In a March 2016 KCBY news article, Richard Dybevik, with Roseburg Forest Products Company, stated that the lower bay is always crowded with boats during the summer and that he has counted as many as 100 boats in that area at one time.[42] (***See Exhibit 42***) **The negative impacts to fishing, crabbing and shellfish habitat would be a significant impact on all those boat users and the fishing industry as a whole.**

CBEMP Policy #5a Temporary Alterations

I. Local governments shall support as consistent with the Plan:

(a) temporary alterations to the estuary, in Natural and Conservation Management Units ***provided it is consistent with the resource capabilities of the management units****. Management unit in Development Management Units temporary alterations which are defined in the definition section of the plan are allowed provided they are consistent with purpose of the Development Management Unit.*

b) alterations necessary for federally authorized Corps of Engineers projects, such as access to dredge material disposal sites by barge or pipeline or staging areas, or dredging for jetty maintenance.

II. Further, the ***actions specified above shall only be allowed provided that****:*

a. ***The temporary alteration is consistent with the resource capabilities of the area (see Policy #4)****;*

b. ***Findings satisfying the impact minimization criterion of Policy #5 are made for actions involving dredge, fill or other significant temporary reduction or degradation of estuarine values****;*

[40] Oregon International Port of Coos Bay Annual Report 2018 – Maritime https://www.oipcbannualreport18.com/maritime
[41] https://theworldlink.com/news/local/who-pays-the-most/article_37797b7c-4711-5608-869b-19dc0ee4e389.html
[42] *After a year of planning, Coos Bay has new marine patrol boat dock;* by KCBY; Wednesday, March 16th 2016 https://kcby.com/news/local/after-a-year-of-planning-coos-bay-has-new-marine-patrol-boat-dock

c. The affected area is restored to its previous condition by removal of the fill or other structures, or by filling of dredged areas (passive restoration may be used for dredged areas, if this is shown to be effective); and
d. The maximum duration of the temporary alteration is three years, subject to annual permit renewal, and restoration measures are undertaken at the completion of the project within the life of the permit.

Mitigation shall not be required by this Plan for such temporary alterations.

This Policy shall be implemented through the administrative conditional use process and through local review and comment on state and federal permit applications.

This Policy is based on the recognition that temporary estuarine fill and habitat alterations are frequently legitimate actions when in conjunction with jetty repair and other important economic activities. It is not uncommon for projects to need staging areas and access that require temporary alteration to habitat that is otherwise protected by this Plan.

CBEMP Policy #8 Estuarine Mitigation Requirements

Local government recognizes that mitigation shall be required when estuarine dredge or fill activities are permitted in inter-tidal or tidal marsh areas*. The effects shall be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained as required by ORS 196.830 (renumbered in 1989). However, mitigation shall not be required for projects which the Division of State Lands determined met the criteria of ORS 196.830(3).* (Emphasis added)

This strategy shall be implemented through procedures established by the Division of State Lands, and as consistent with ORS 196.830 and other mitigation/restoration policies set forth in this Plan.

This strategy recognizes the authority of the Director of the Division of State Lands in administering the statutes regarding mitigation.

CBEMP Policy #11 Authority of Other Agencies

Local government shall recognize the authority of the following agencies and their programs for managing land and water resources:
~ The Oregon Forest Practices Act and Administrative Rules for forest lands as defined in ORS 527.620(1991) to 527.730 and Forest Lands Goal;
~ The nonpoint source discharge water quality program administered by the Department of Environmental Quality (DEQ) under Section 208 of the Federal Water Quality Act as amended in 1972 (PL 92-500);
~ The Fill and Removal Permit Program administered by the Division of State Lands (DSL) under ORS 196.800-196.880 (renumbered 1989); and
~ The programs of the State Soil and Water Conservation Commission and local districts and the Soil Conservation Service and the Agricultural Lands Goal.

<u>This strategy recognizes there are several agencies with authority over coastal waters, and that their management programs should be used rather than developing new or duplicate management techniques or controls</u>, *especially as related to existing programs functioning to maintain water quality and minimize man-induced sedimentation.*

<u>This strategy shall be implemented through the permit coordination with ODFW and the Army Corps of engineers prior to County sign-off on permits</u>.

CBEMP Policy #14 General Policy on Uses within Rural Coastal Shorelands

1. Coos County shall manage its rural areas within the "Coos Bay Coastal Shorelands Boundary" by allowing only the following uses in rural shoreland areas, as prescribed in the management units of this Plan, except for areas where mandatory protection is prescribed by LCDC Goal #17 and CBEMP Policies #17 and #18:

* * * *

e. Water-dependent commercial and industrial uses, water-related uses, and other uses ***<u>only upon a finding by the Board of Commissioners or its designee that such uses satisfy a need which cannot be accommodated on uplands or shorelands in urban and urbanizable areas or in rural areas built upon or irrevocably committed to non-resource use</u>***. (Emphasis added)

* * * *

g. Any other uses, including non-farm uses and non-forest uses, provided that the Board of Commissioners or its designee determines that such uses <u>satisfy a need which cannot be accommodated at other upland locations or in urban or urbanizable areas.</u> ***<u>In addition, the above uses shall only be permitted upon a finding that such uses do not otherwise conflict with the resource preservation and protection policies established elsewhere in this Plan</u>***. (Emphasis added)

This strategy recognizes (1) that Coos County's rural shorelands are a valuable resource and accordingly merit special consideration, *and (2) that LCDC Goal #17 places strict limitations on land divisions within coastal shorelands. This strategy further recognizes that rural uses "athrough "g" above, are allowed* ***because of need and consistency findings documented in the "factual base" that supports this Plan.*** (Emphasis added)

Policy 14 requirements clearly link it to other CBEMP Policies and require compliance so there is no conflict with the preservation and protection of estuary resources. This clearly links Policy 14 to CBEMP Policy 5 along and other CBEMP Policies and also requires that <u>alternatives that would not impact the high value Coastal Shoreland areas of the Coos Estuary are considered</u>.

CBEMP Policy #16 Protection of Sites Suitable for Water-Dependent Uses and Special Allowance for new Non-Water-Dependent Uses in "Urban Water-Dependent (UW) Units"

Local government shall protect shorelands in the following areas that are suitable for waterdependent uses, for water-dependent commercial, recreational and industrial uses.

a. Urban or urbanizable areas;
b. Rural areas built upon or irrevocably committed to non-resource use; and
c. Any unincorporated community subject to OAR Chapter 660, Division 022 (Unincorporated Communities).

This strategy is implemented through the Estuary Plan, which provides for water-dependent uses within areas that are designated as Urban Water-Dependent (UW) management units

* * * *

II. Suitability. The shoreland area within the estuary designated to provide the minimum amount of protected shorelands shall be suitable for water-dependent uses. At a minimum such water-dependent shoreland areas shall possess, or be capable of possessing, structures or facilities that provide water-dependent uses ***with physical access to the adjacent coastal water body****. The designation of such areas shall comply with applicable Statewide Planning Goals.* (Emphasis added)

* * * *

This policy shall be implemented through provisions in ordinance measures that require an administrative conditional use application be filed and approved, and the above findings be made prior to the establishing of the proposed uses or activities.

CBEMP Policy #17 Protection of "Major Marshes" and "Significant Wildlife Habitat" in Coastal Shorelands

Local governments shall protect from development, major marshes and significant wildlife habitat, coastal headlands, and exceptional aesthetic resources located within the Coos Bay Coastal Shorelands Boundary, except where exceptions allow otherwise.

I. ***Local government shall protect****:*

a. "Major marshes" to include areas identified in the Goal #17, "Linkage Matrix", and the Shoreland Values Inventory map; and

b. "Significant wildlife habitats" to include those areas identified on the "Shoreland Values Inventory" map; and

c. ~~"~~Coastal headlands"; and

*d. ~~"~~****Exceptional aesthetic resources" where the quality is primarily derived from or related to the association with coastal water areas****.* (Emphasis added)

II. This strategy shall be implemented through:

a. Plan designations, and use and activity matrices set forth elsewhere in this Plan that limit uses in these special areas to those that are consistent with protection of natural values; and

b. Through use of the Special Considerations Map, which identified such special areas and restricts uses and activities therein to uses that are consistent with the protection of natural values. Such uses may include propagation and selective harvesting of forest products consistent with the Oregon Forest Practices Act, grazing, harvesting wild crops, and low-intensity water-dependent recreation.

c. Contacting Oregon Department of Fish and Wildlife for review and comment on the proposed development within the area of the 5b or 5c bird sites.

This strategy recognizes that special protective consideration must be given to key resources in coastal shorelands over and above the protection afforded such resources elsewhere in this Plan.

CBEMP Policy #20a. Dredged Material Disposal Guidelines:

Future dredged material disposal should be carried out in accordance with the guidelines outlined in Volume II, Part I, Section 6.2 of the Plan, which relate to: drainage diversion, sediment quality and turbidity, timing of disposal, land surface use, revegetation, toxic materials, land use outfalls and influent discharge points, water quality and removal of material from approved upland sites. *Future land use shall be governed by the uses/activities permitted and the Management Objective in that management unit. Additional guidelines contained in the "Special Considerations" section of the individual site fieldsheets (see Inventory and Factual Base, Volume II, Part 2, Section 7, Appendix 'A') provide site-specific information on the procedures that should be followed.*

These guidelines are intended to indicate the type of conditions that federal and state agencies are likely to impose on dredged material disposal permits, which shall be the primary means of implementation. Local government shall implement this policy by review and comment on permit applications.

* * * *

(Emphasis added)

CBEMP Policy #20c Intertidal Dredged Material Disposal

Local government shall prohibit dredged material disposal in intertidal or tidal marsh areas except where such disposal is part of an approved fill project.
This strategy shall be implemented through operation of the waterway permit process as a response to a "request for comment" from the Division of State Lands and U. S. Army Corps of Engineers.

This strategy recognizes that upland disposal and ocean disposal are alternatives to intertidal disposal.
(Emphasis added)

CBEMP Policy #23 Riparian Vegetation and Streambank Protection

I. ***Local government shall strive to maintain riparian vegetation within the shorelands of the estuary, and when appropriate, restore or enhance it****, as consistent with water-dependent uses. Local government shall also encourage use of tax incentives to encourage maintenance of riparian vegetation, pursuant to ORS 308.792 - 308.803.* (Emphasis added)
Appropriate provisions for riparian vegetation are set forth in the CCZLDO Section 3.2.180 (OR 92-05-009PL). (Emphasis added)

II. Local government shall encourage streambank stabilization for the purpose of controlling streambank erosion along the estuary, subject to other policies concerning structural and non-structural stabilization measures.

This strategy shall be implemented by ***Oregon Department of Transportation (ODOT****) and local government where erosion threatens roads. Otherwise, individual landowners in cooperation with the* ***Oregon International Port of Coos Bay****, and* ***Coos Soil and Water Conservation District, Watershed Councils, Division of State Lands and Oregon Department of Fish & Wildlife*** *shall be responsible for bank protection.*

This strategy recognizes that the banks of the estuary, particularly the Coos and Millicoma Rivers are susceptible to erosion and have threatened valuable farm land, roads and other structures.

CBEMP Policy #27 Floodplain Protection within Coastal Shorelands

The respective flood regulations of local government set forth requirements for uses and activities in identified flood areas; these shall be recognized as implementing ordinances of this Plan.

This strategy recognizes ***the potential for property damage that could result from flooding of the estuary***. (Emphasis added)

CBEMP Policy #47 Environmental Quality

The Coos Bay Estuary Management Plan and Implementing Ordinance ***shall comply with the Department of Environmental Quality (DEQ) regulations regarding air, water quality and noise source standards that are established as law***. (Emphasis added)

Various other CBEMP polices must also be followed including CBEMP Policies 4, 4a, 7, 18, 19, 33, 22b, 24, 48, 50, among several others.

There is no American public benefit to the loss of fish, marine and wildlife habitat due to the destructive nature of all the proposed dredging for the Jordan Cove / Pacific Connector Project. The Pacific Connector Pipeline's construction is projected to impact 485 wetlands and waterbodies in Southern Oregon, many of which are salmon bearing.

The Coos Bay Estuary is already 303D limited and this project will only make that situation worse. We can look to what has happened at other LNG projects with respect to channel dredging and see that **even though the LNG industry promises there would be no negative impacts, promises and what actually happens does not always end up being the same**. (***See Exhibit 14***) Our fishing industry has ALREADY been negatively impacted and is in need or renewal, not more degradation. (***See Exhibit 15)*** Jordan Cove expects us to believe that there would be no negative impacts with sedimentation or turbidity from all their proposed dredging. Our sedimentation expert actually proved their expert to be wrong on this issue during the land use process under Coos County File No. REM 10-01 for HBCU-10-01. (***See Exhibit 29)***

In order to protect the integrity of the Estuary, Policy 5 requirements must be adhered to and marine habitat in the estuary protected. This is even a requirement in **DDNC-DA** zoning district for which the **applicant is not seeking a goal exception for**. The strong tidal currents in the Coos Estuary have the ability to transfer sediments a great distance**. No contaminated soils or fill should be suspended in the estuary.** The applicant should be made to test the tidal muds and mitigate for any damage that may be done. In addition, evacuation measures in the event of an earthquake and/or tsunami event off our coastline should also be taken into account as a part of permit requirements in order to fulfill the Comprehensive Plan's purpose of protecting the public health, safety, convenience and general welfare of local citizens.

In 2010, Clausen Oyster Company was hit with a $25,000 fine from the Oregon Department of Environmental Quality for wastewater violations. Clausen maintained that no oyster meat was entering the wash water - just mud that it was washing off the oyster that had just been taken out of the bay. "The mud comes out of the bay; it goes back in the bay," said Lilli Clausen. (***See Exhibit 33***) Despite the fact that the mud had just come out of the bay it was still considered a Clean Water Act violation.

The same scrutiny and oversight should be imposed with respect to the Jordan Cove Project and their proposed placement of fill and/or sedimentation in Waters of the State due to the negative impacts those sediments could have on fishing and recreation.

This should be of particular concern due to the fact that Jordan Cove has ALREADY been sited by the DEQ for violations with respect to their Project for work they were doing on May 8, 2014, at the Jordan Cove Ingram Yard site (***See Exhibit*** 68)

NEGATIVE IMPACTS ON NAVIGATION

The Coast Guard's July 1, 2008, Water Suitability Assessment (WSA) Report for the Jordan Cove project states on page 1 ―*that Coos Bay is **<u>not currently suitable</u>**, but could be made suitable for the type and frequency of LNG marine traffic associated with this proposed project*." [43] (Emphasis added) Coast Guard mitigation measures include **limiting the LNG carrier to the physical dimensions of a 148,000 m3 class vessel**. The ship dimension used in the study reflected an overall length of 950 feet and a beam of 150 feet with a loaded **<u>draft of 40 feet</u>**. [44] (***See Exhibit 30***)

Jordan Cove's updated Resource Report #1 filed with the FERC on November 16, 2018 [45] states on page 41 (electronic page 82):

> *The waterway for LNG vessel marine traffic would traverse 7.5 miles of the existing Federal Navigation Channel within Coos Bay. The Federal Navigation Channel is zoned ―Deep-Draft Navigation Channel" in the CBEMP. **<u>The Federal Navigation Channel, which is generally 300 feet wide and 37 feet deep</u>**, is maintained by the USACE on behalf of the Port. It is used by deep-draft commercial ships and barges, a commercial fishing fleet, and recreational boats*. (Emphasis added)

JCEP Nov 16, 2018 Update Resource Report #1 pages 25 to 26:

> *The Project's plans for the LNG carriers calling on the LNG Terminal and their transit route in Coos Bay, as described below, are primarily within the jurisdiction of the USCG. Because the USCG has authorized carriers of approximately 950 feet length, 150 feet beam, and loaded draft of 40 feet (nominal 148,000 m^3)[2] as the size of LNG carrier, the LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. The actual number of LNG carriers per year will be dependent on the capacity of the LNG carriers calling on the LNG Terminal and the actual output production of the LNG Terminal. The LNG loading berth is designed so that it could*

[43] Coast Guard WSA for Jordan Cove LNG project, July 2008: https://homeport.uscg.mil/Lists/Content/Attachments/1008/WSRscan.pdf

[44] https://homeport.uscg.mil/Lists/Content/DispForm.aspx?ID=1008

[45] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198

accommodate LNG carriers up to 217,000 m^3 if larger-sized carriers were to be authorized by the USCG in the future, resulting in a reduced number of LNG carrier calls each year

JCEP Nov 16, 2018 Update Resource Report #1 page 36:

> *The LNG Terminal would be located on the bay side of the North Spit, about 7.5 miles up the existing Federal Navigation Channel,* ***<u>approximately 1,000 feet north of the city limit of North Bend</u>****, in Coos County, Oregon*

Page 2 of the Coast Guard WSA states that ―*the channel* ***must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed***." (Emphasis added) As noted above the Coos Bay is only dredged to 37 feet currently. LNG ships would transit the bay during high slack tides, the same tides used by the fishing fleet.

On May 10, 2018 the U.S. Coast Guard ignored FAA Presumed Hazard determinations for LNG tanker ships in the Coos Bay Estuary and many other channel hazard concerns including those listed in their 2008 WSA, and blindly issued a Letter of Recommendation (LOR) that stated the Coos Bay was now suitable for LNG traffic.[46] (?) If that is the case why is Jordan Cove currently proposing modifications to the Coos Bay channel? The May 2018 LOR included in with it the July 2008 WSA which clearly states that the Coos Bay waterway is ―not" suitable, so the entire document kind of contradicts itself.

LNG VESSEL TRANSITS AND CHANNEL DEPTHS NOT COMPATABLE

Jordan Cove's Ship Simulation Study modeled its LNG carrier dimensions at 950 feet long, 150 feet at the beam, with a loaded draft of 40 feet deep, and a capacity of 148,000 m3**.**[47] **LNG ships with a 40 foot draft would transit the Coos Bay Navigation Channel that is dredged only 300 feet in width and 37 feet in depth.** (JCEP Rev RR#1) LNG vessels would be arriving and leaving at high tide (WSA page 3).

On February 13, 2015, Jordan Cove uploaded into the FERC library their 2008 Report "*148,000 m3 Class LNG Carrier Transit and Maneuvering Simulations March 17-20, 2008*" by Moffatt & Nichol. This report clearly shows that the Coos Bay Navigation Channel is NOT SUFFICIENT FOR TRANSITING LNG VESSELS.

Modeling items noted upon review of the 2008 LNG Carrier study are as follows:

Electronic page 174
Run 17030801
LNG ship hits Slip Channel Entrance Cement Barrier

Electronic page 193-195
Run 17030802
Maneuvering Tugboat on the wrong side of the Slip Channel Entrance Cement Barrier
LNG ship and Maneuvering tugs very close to hitting buoy

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[46] https://content.govdelivery.com/accounts/USDHSCG/bulletins/1ef91ba

[47] 2-13-2015 filing with FERC by JCEP Re- USACE Permit Application of Jordan Cove Energy Project, L.P. under CP13-483. includes 2008 Report "*148,000 m3 Class LNG Carrier Transit and Maneuvering Simulations March 17-20, 2008*" by Moffatt & Nichol http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150213-5115

Electronic page 212
Run 17030804
LNG Ship runs over buoy

Electronic page 242-243
Run 18030802
Maneuvering Tugboat runs over buoy

Upon review of a NOAA Channel map of the Coos Bay - 70th Edition – Oct 2005 # 18587, channel depths vary greatly and do not always remain at the dredging depth of 37 feet. Please note photo taken of one section of the map below.

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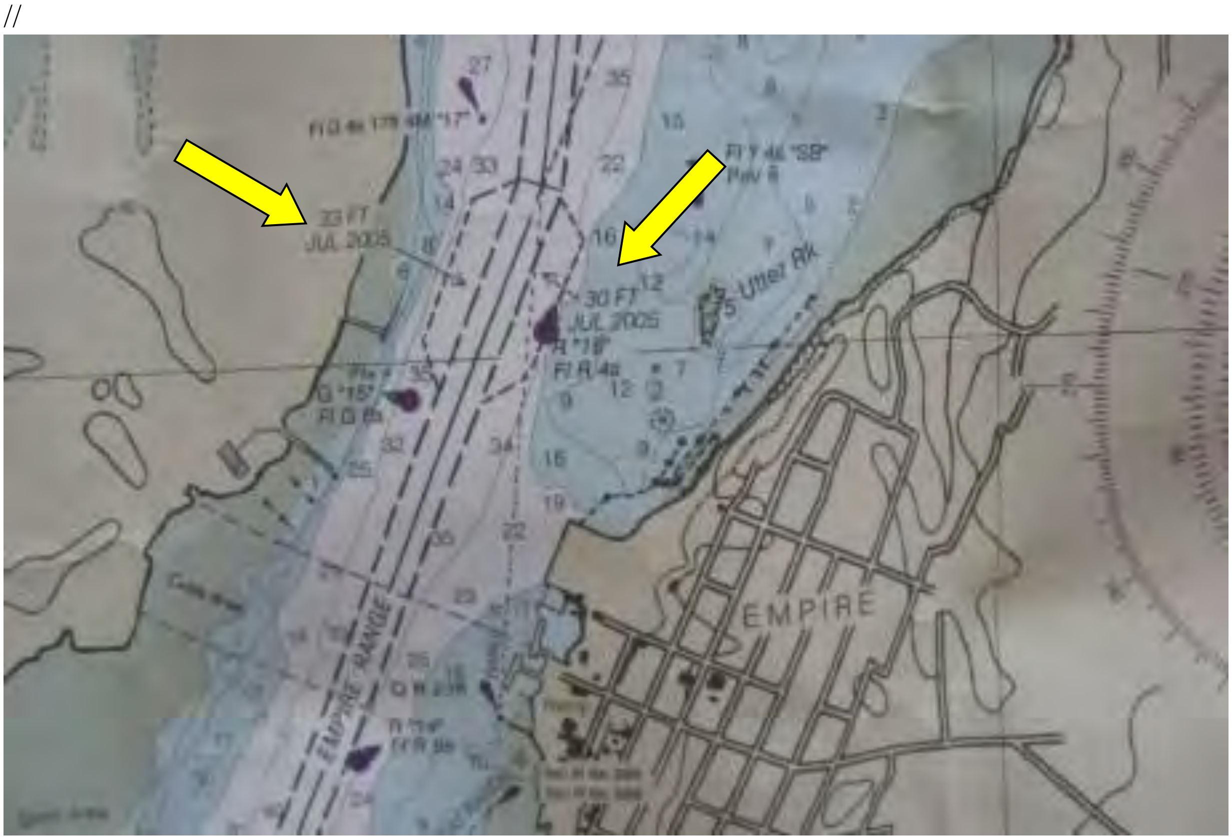
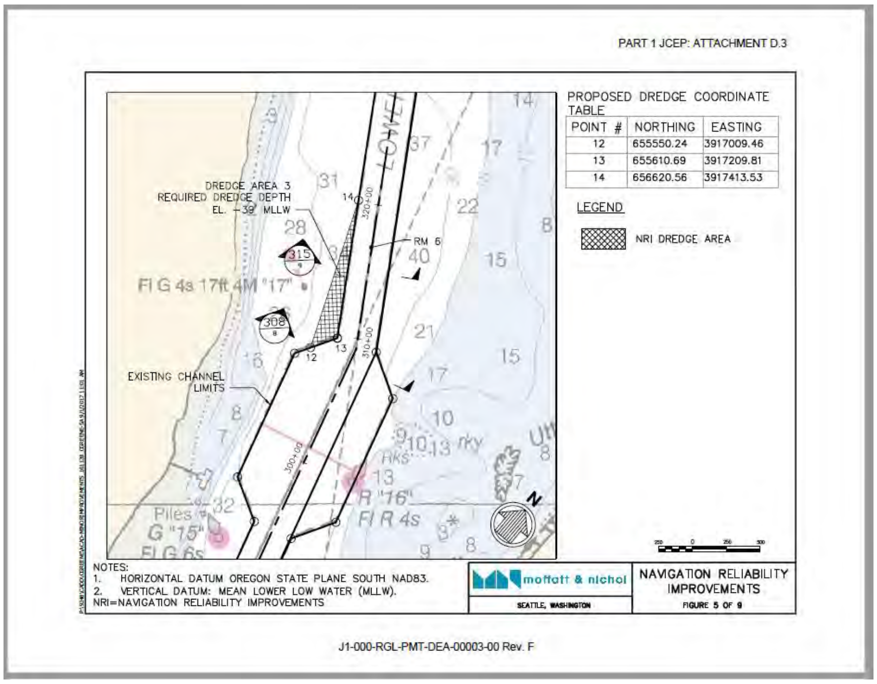


As noted in this NOAA channel map from Oct 2005, sections of the channel just North of the Empire Community were shown to be at 30 feet and 33 feet in July of 2005.

Below Jordan Cove proposed dredge area #3 site in this same area (JCEP DSL application electronic page 436) shows **Coos Bay shallow channel issues would not totally be alleviated**

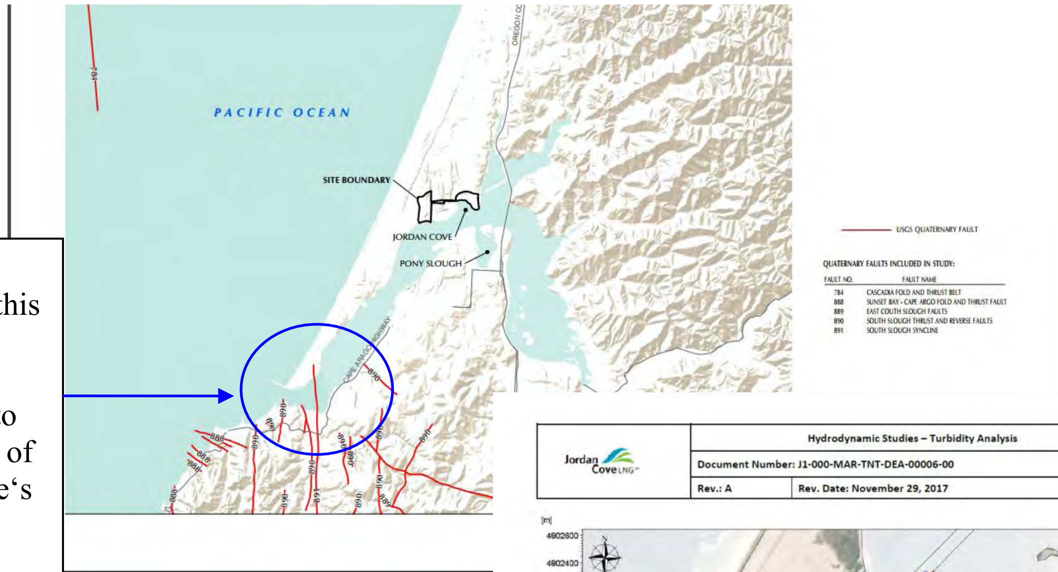


How does the Coast Guard and the Jordan Cove Energy Project plan to account for these issues in regard to JCEP's transiting LNG Carriers, which are designed to have a 40-foot draft? Even transiting at high slack tide this does not appear to be a sufficient clearance.

The Guano Rock formation found at the Coos Bay Harbor entrance would make it difficult for LNG tanker traffic and/or any efforts to widen and deepen the channel. Attempts to blast the rock would have dire consequences on water quality and marine life in the area and could very well bring on an earthquake or at least impact the earthquake fault that runs diagonally through the Bay in this same area. This was not considered in Jordan Cove's application.

Page 130 of Jordan Cove's 1-12-2016 submittal into the Coos County file No. HBCU-15-05 land use proceeding was from their GRI report and shows the following Earthquake Faults that were included in their study with respect to the LNG terminal only:

Note the location of this earthquake fault and compare it to the location of Jordan Cove's proposed channel dredging project below which is extremely close to this fault.



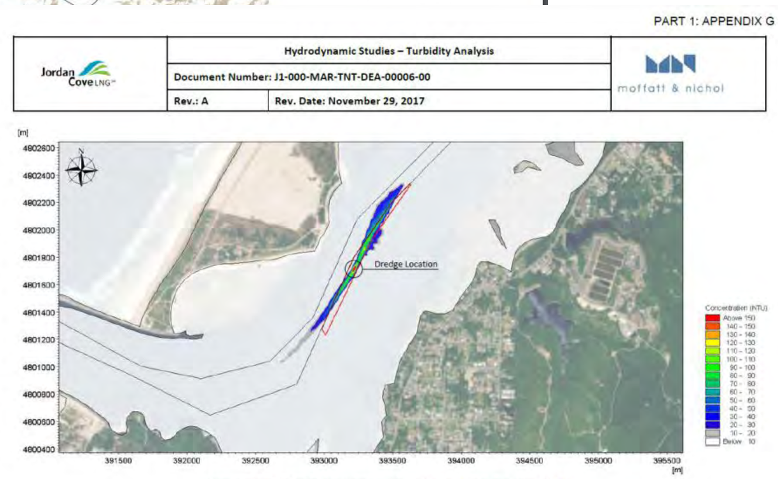
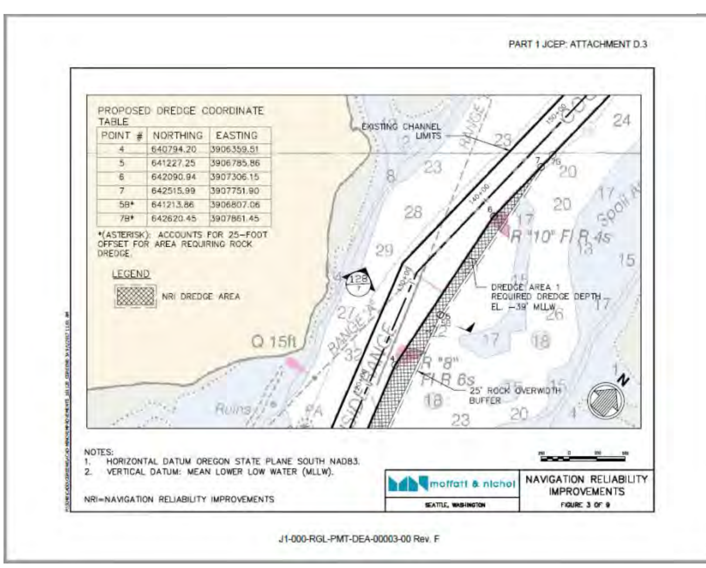
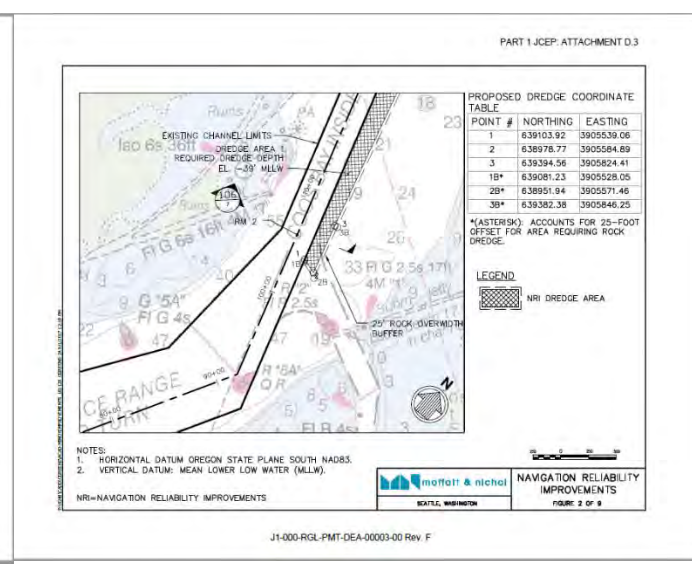


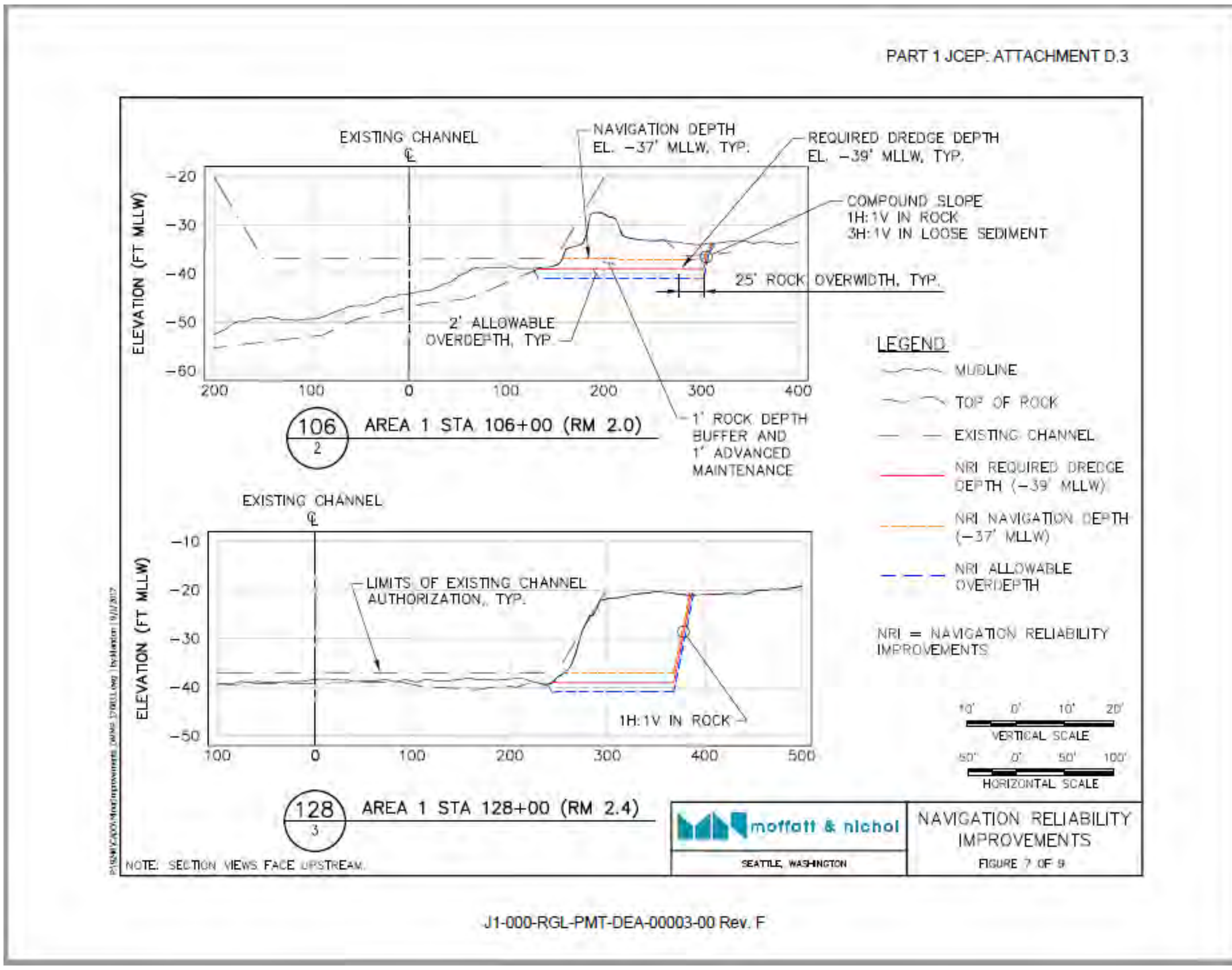
Figure 5-1: Capital dredging with cutter suction dredge, NRI 1

Jordan Cove's proposed dredge area #1 will inv

See diagrams below from DSL application electronic pages 433,434 and 438.







The Jordan Cove GRI study did not include negative impacts from the earthquake fault line or on habitat from all the blasting that would be required for proposed dredging in area #1.

At the Port Harbor Safety meeting held on January 15, 2019, Jordan Cove's consultant told everyone that the LNG ships would only have to transit during high slack tide when they were outgoing. Incoming LNG ships would be able to transit the channel at any time.

Despite Jordan Cove's recently refiled Resource Report #1 stating that the LNG ships would have an approximate loaded draft of 40 feet, Jordan Cove's consultant assured us that the ships had only a 37 foot draft at the Jan 15th Harbor Safety meeting. It wasn't clear how a 37 foot drafted ship could transit a 37 foot dredged channel, but even if Jordan Cove is allowed to dredge the channel down to 39 feet, by stating that this is a ―required dredge depth" for a 37 foot navigational channel, **that still does not give enough clearance allowance**.

Criteria for the Depths of Dredged Navigational Channels Dec 12, 1983
https://apps.dtic.mil/dtic/tr/fulltext/u2/a135628.pdf

> Rules of Thumb The criteria used by the U.S. Army Corps of Engineers are empirical--rules of thumb. For design depth, or underkeel clearance, the rule is to select the design ship, add its draft + squat* (3 ft) + rolling and pitching allowance (estimate) + clearance (2 ft for soft channel bottoms; 3 ft for rocky or hard bottoms). The Corps' criteria recommend model tests and site evaluations.

The Feb 2018 Coos Bay Harbor Safety Plan[48] on electronic page 62 it states the following:

> *Guidelines for Under Keel Clearance in Coos Bays is on average 10% and is established by each vessel in consultation with the pilots.*

Ten percent of a 37 foot drafted ship would be 3.7 feet and of a 40 foot drafted ship would be 4 feet. **There is NOT enough clearance in the Coos Bay for safe passage of LNG tankerships even with Jordan Cove's proposed navigation improvements.**

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 17: (***See Exhibit 31***)

> **3.5 Anchorage**
>
> *　　*　　*　　*
>
> *Due to the rapid and severe onset of weather from the North Pacific Ocean, **<u>anchorage in the ocean outside of Coos Bay is reported not safe and is dangerous during the winter months</u>**. Like all unprotected areas along the Oregon coast, large swells and heavy winds characterize the area during the winter. These conditions can suddenly and unexpectedly besiege the unwary with catastrophic results. The prevailing direction of both swell and wind will drive disabled or improperly handled vessels onto the shore.*
>
> *While desired, **<u>there are currently no designated anchorage areas off the coast or within the channel, primarily due to the grounding of the M/V New Carissa in 1999 off the coast of Coos Bay</u>**.* (Emphasis added)

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 26:

> ***4.1.3 Prevailing winds***
>
> *Prevailing winds in the offshore sector are southerly winds, **<u>15-30 knots, in the summer</u>** **<u>and most of the year</u>** but shifting to northerly winds in the winter. Prevailing NW winds and winter southerly storms.*
>
> - *25 knots winds and above affect big ship movements*
>
> *　　*　　*　　*
>
> *Deep draft ships are warned of anchoring offshore during winter while awaiting calmer winds to transit. **<u>The rapid and severe onset of weather may expose the vessel to the risk of dragging ashore</u>**.* (Emphasis added)

U.S. Coast Guard July 2008 Water Suitability Report states on page 3:

> ***<u>Tug Escort and Docking Assist</u>****: ...Based on the ship simulation study conducted by Moffatt and Nichol on March 17-20, 2008, **<u>vessels are limited to transiting during periods of high tide and 25 knot winds or less</u>**. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.* (Emphasis added)

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48 https://static1.squarespace.com/static/569e6f1176d99c4f392858c4/t/5abc1b252b6a28c8f42cfd14/1522277173846/Coos+Bay+HSP+2018FEB20+update+2018MAR27.pdf

If LNG vessels are to remain off-shore in bad weather HOW DOES THIS MAKE US SAFE? **No Plan exists that I know of with respect to SAFE offshore anchoring or maneuvering of LNG tanker ships off of Coos Bay for periods when winds exceed 25 knots.** How do they plan to prevent another New Carissa grounding or WORSE?

GUIDELINES FOR SAFETY ARE NOT BEING FOLLOWED

Many of the guidelines for safety that are suggested in the gas industries own "*Society of International Gas Tanker & Terminal Operators"* (SIGTTO**)**[49] Information Paper No. 14 have been completely ignored in this terminal siting.

Examples of SIGTTO guidelines not addressed adequately include:

1) **Approach Channels. Harbor channels should be of uniform cross-sectional depth and have a minimum width, <u>equal to five time the beam of the largest ship</u>**
2) **Turning Circles. <u>Turning circles should have a minimum diameter of twice the overall length of the largest ship</u>, where current effect is minimal. Where turning circles are located in areas of current, diameters should be increased by the anticipated drift.**
3) **Tug Power. Available tug power, expressed in terms of effective bollard pull, should be sufficient to overcome the maximum wind force generated on the largest ship using the terminal, under the maximum wind speed permitted for harbor maneuvers and with the LNG carrier's engines out of action.**
4) **Site selection process should <u>remove as many risk as possible</u> by placing LNG terminals in <u>sheltered locations remote from other port users</u>. Suggest port designers construct jetties handling hazardous cargoes in remote areas where ships do not pose a (collision) risk and <u>where any gas escaped cannot affect local populations.</u> Site selection should limit the risk of ship strikings, limiting interactive effects from passing ships and reducing the risk of dynamic wave forces within mooring lines.**
5) **Building the LNG terminal on the outside of a river bend is considered unsuitable due to fact that a passing ship may strike the berthed carrier if the maneuver is not properly executed.**
6) **SIGTTO Examples given for reducing risk factors beyond normal operations of ship/shore interface include LNG terminal patrols of the perimeter of the offshore safety zones with guard boats and <u>to declare the air-space over an LNG terminal as being a restricted zone where no aircraft is allowed to fly</u> without written permission.**
7) **Restriction of the speed of large ships passing close to berthed LNG carriers.**

Also ignored were some of the safety guideline preventative measures found in the Sandia National Laboratories Report – "*Guidance on Risk Analysis and Safety Implications of Large Liquefied Natural Gas (LNG) Spill Over Water*" – Dec 04:

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[49] **Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14 -** Published by *Society of International Gas Tanker and Terminal Operators Ltd* / 1997

Guidelines (Pg 64) include: [50]

1) Appropriate off-shore LNG ship interdiction and inspections for explosives, hazardous materials, and proper operation of safety systems;
2) Appropriate monitoring and control of LNG ships when entering U.S. waters and **protection of harbor pilots and crews**;
3) **Enhanced safety zones around LNG vessels (safety halo) <u>that can be enforced</u>;**
4) **<u>Appropriate control of airspace over LNG ships</u>**; and
5) **Appropriate inspection and protection of terminal areas, tug operations prior to delivery and unloading operations.**

In addition, scientist have found that safety measures incorporated in the proposed Jordan Cove LNG terminal actually increase the chance of a catastrophic failure and present a far more serious public safety hazard than regulators have analyzed and deemed acceptable.[51] Jerry Havens , Distinguished Professor of Chemical Engineering at University of Arkansas, and James Venart, Professor Emeritus of Mechanical Engineering at University of New Brunswick, have asked specific questions to the FERC concerning these hazard issues. [52] Those questions need to be addressed properly. This would impact potential future industry and the Ports proposed Oregon Gateway cargo terminal to the East of the proposed LNG facility, which would not be allowed to operate in these hazard areas.

*―Once ignited, as is very likely when the spill is initiated by a chemical explosion, the floating LNG pool will burn vigorously…Like the attack on the World Trade Center in New York City**, there exists no relevant industrial experience with fires of this scale from which to project measures for securing public safety**.*" – Statement by Professor James Fay, Massachusetts Institute of Technology (Emphasis added.)

Sandia Laboratory's Dec 2004 Report; "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water",* states on page 83; "*... The distance from the fire to an object at which the radiant flux is 5 kW/m2 is 1.9 km"* (1.181 miles). **To clearly understand this one must understand that 5 kW/m2 is the heat flux level that can cause 2nd degree burns on exposed human skin in 30 seconds.**

An estimated 16,922 people would live in the hazardous zones of concern according to the former Jordan Cove Export Final EIS (page 4-1031) under CP13-483-000/CP13-492-000, and yet there is little concern given for their safety. Trees and burnable scrub brush cover our area. Secondary fires will be paramount and **most of our emergency responders are located in the LNG hazardous zones of concern**. The Coos Bay area has one hospital, it does not have a ―Burn Unit." We have yet to see an emergency response plan on how the medical response to even a minor LNG hazardous event could be handled in light of our area's obvious insufficiency of appropriate medical facilities and personnel.

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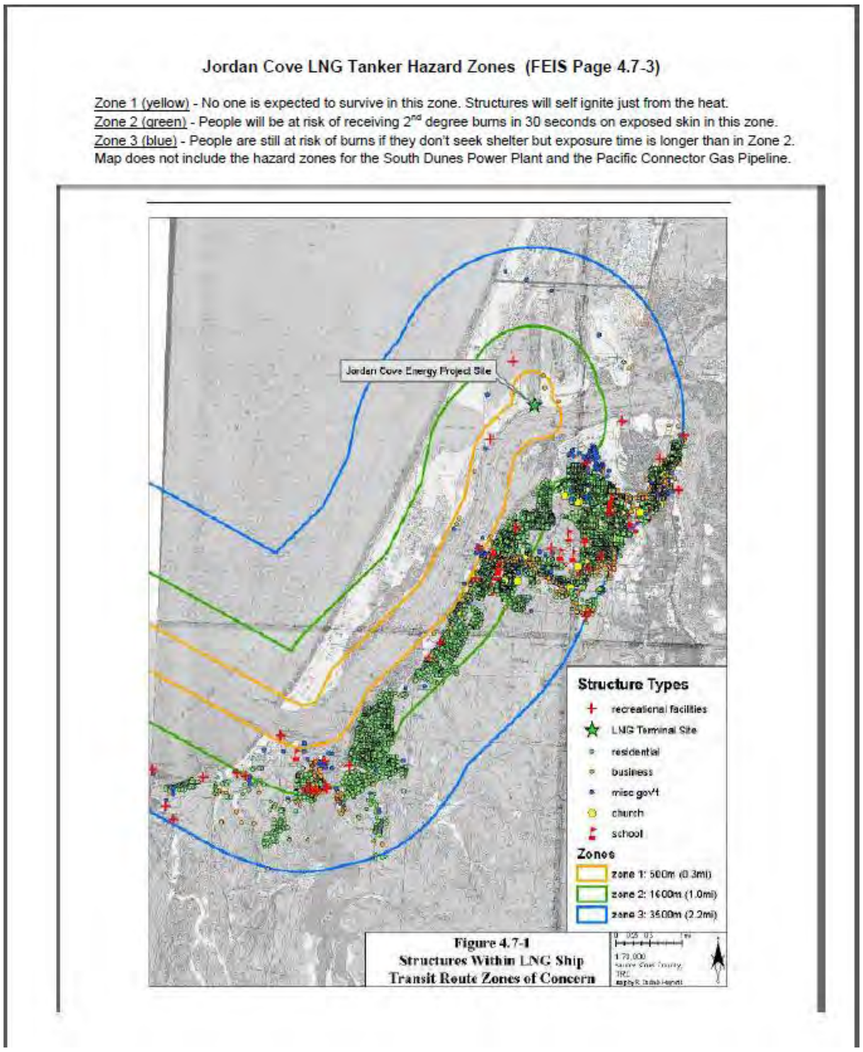
[50] Without an emergency response plan to review it is hard to know if some of these recommendations have been met.
[51] January 14, 2015 Report filed by Jerry Havens Ph.D and James Venart Ph.D. to FERC concerning *discrepancies and problems with Jordan Cove Energy Project hazard analysis* under CP13-483 et. al.
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150114-5038
[52] Feb 6, 2014 Follow-up Report/ *Questions concerning discrepancies and problems with Jordan Cove's hazard analysis* under CP13-483 et al.
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150206-5040

This was just one of many concerns that were raised in scoping comments to FERC that have yet to be addressed.



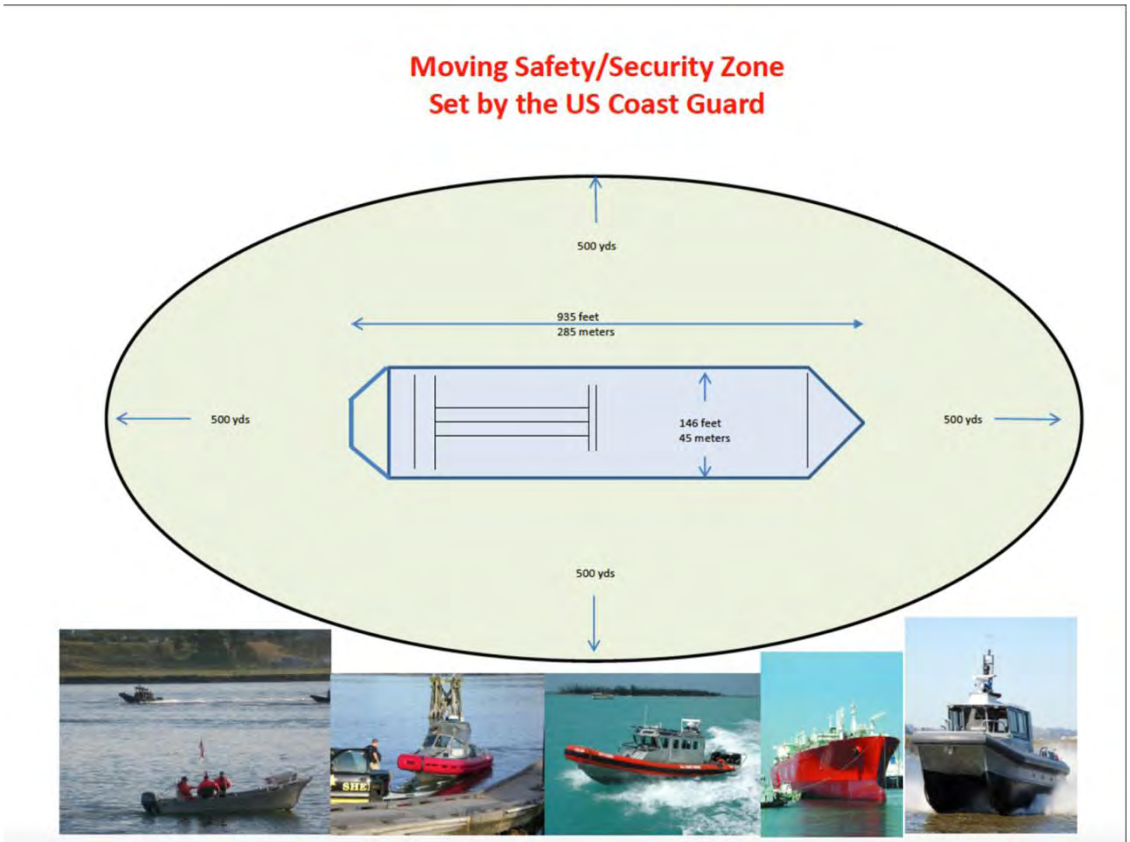
Above Diagram from Jordan Cove Import Final EIS page 4.7-3 under CP07-444-000/CP07-441-00.

Negative Impacts to other Bay Users

The Coast Guard WSA also established Safety / Security Zones for LNG vessels **both** while the vessels are moored and when they are not moored. When an LNG vessel is at the docking facility there is to be a 150 yard security zone around it, to include the entire terminal slip, and when there is no LNG vessel moored, the security zone will cover the entire terminal slip and extend 25-yards into the waterway. (See CG-WSA page 2) In addition, the Coast Guard has set a moving safety/security zone for the LNG tanker ship that extends 500-yards around the vessel but ends at the shoreline. **No vessel may enter the safety / security zone without first obtaining permission from the Coast Guard Captain of the Port who resides in the Portland, OR office**.[53] (See CG-WSA page 2)

This safety and security zone will encompass the entire bay in some areas and be a hindrance to other port users including recreational and commercial fishermen.

[53] Coast Guard - LOR / WSR / WSA for Port of Coos Bay / Jordan Cove Energy Project: https://homeport.uscg.mil/Lists/Content/DispForm.aspx?ID=1008



The Coast Guard WSA states on page 3 under Tug and Docking Assist:

> *…Based on the Ship simulation Study conducted by Moffatt & Nichol on March 17 -20, 2008, **vessels are limited to transiting during periods of high tide and 25 knot winds or less**. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.*

This is also optimal tides that the fishing fleet uses.

How close is too close for proposed transiting LNG Tanker Ships in Coos Bay? (***See Exhibit 32***)

Photos above are of cargo ships transiting our Coos Bay Harbor. These ships are considerably smaller than LNG ships. (See photo comparison below) The photo above on the left is the view from the deck of a local homeowner. The photo on the right is from the Boat House Auditorium in Charleston at a Coos County Board of Commissioners meeting held on July 10, 2012. A wood transport ship passes by in the Coos Bay Channel next to the Boat House Auditorium

Below a typical local cargo ship as compared to a smaller LNG ship

The LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. [Jordan Cove RR #1 page 25 & 26]

This amounts to 220 to 240 harbor disruptions per year during high slack tides which are also prime tides used currently by other bay users.

If the Coast Guard choses to not follow their own Water Suitability Assessment requirements designed to protect the safety and security zone around both a transiting and docked LNG tanker ship, they would be placing some 20,000 to 40,000 people in Coos Bay Area at extreme risk, including Coast Guard personnel.

NEGATIVE IMPACTS ON THE AIRPORT

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 18:

> ***Southwest Oregon Regional Airport***: *For safety reasons, the FAA limits the height of vessel transiting in front of the runway. Inbound and outbound vessel traffic near the Airport may affect procedures for aircraft landing and departing at the airport. Vessels with an air draft of 144 feet or greater present a potential obstruction to airspace that requires advisories be issued to aircraft by air traffic controllers, and in some cases, runway use may need to be restricted. See Special Navigational Conditions for more for more details.*

On May 7, 2018 the FAA released 13 determinations of PRESUMED AIRPORT HAZARD with respect to the proposed Jordan Cove Project.[54] Jordan Cove has not resolved these issues and

[54] See Part 8 of Jordan Cove response filing with the FERC that includes the 13 FAA documents: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180510-5165

they are __not able to be mitigated__. Nine of these FAA Presumed Airport Hazards involve transiting LNG tanker ships at various points within the Coos Bay Estuary**.** **(*See Exhibit 1 filed on June 10, 2019*) This would be devastating to the Southwest Oregon Regional Airport operations, navigation and fishing. It clearly violates __OAR 141-122-0020(5)(a)__ and __ORS 196.825(1)(a)(b);(3)(a)(e)__**

Presumed Airport Hazards are included in this document as follows:

- LNG Carrier Vessel - Stack, Transit Point 6 - 2018-ANM-720-OE
- LNG Carrier Vessel - Stack, Transit East Point - 2018-ANM-719-OE
- LNG Carrier Vessel - Stack, Transit West Point - 2018-ANM-718-OE
- LNG Carrier Vessel - Stack, Transit Point 5 - 2018-ANM-8-OE
- LNG Carrier Vessel - Stack, Transit Point 4 - 2018-ANM-7-OE
- LNG Carrier Vessel - Stack, Transit Point 3 - 2018-ANM-6-OE
- LNG Carrier Vessel - Stack, Transit Point 2 - 2018-ANM-5-OE
- LNG Carrier Vessel - Stack, Transit Point 1 - 2018-ANM-4-OE
- LNG Carrier Vessel - Stack - 2017-ANM-5418-OE
- Amine Regenerator - 2017-ANM-5389-OE
- Oxidizer - 2017-ANM-5388-OE
- LNG Tank North - 2017-ANM-5387-OE
- LNG Tank South - 2017-ANM-5386-OE

The Director of Dept of State Lands should deny the application due to the Project clearly being out of compliance with ORS 196.825(1)(a)(b);(3)(a)(e) and OAR 141-122-0020(5)(a):

> *~~—~~The Director of the Department of State Lands shall issue a permit applied for under ORS 196.815 (Application for permit) if the director determines that the project described in the application:*
>
> *(a) Is consistent with the protection, conservation and __**best use of the water resources of this state**__ as specified in ORS 196.600 (Definitions for ORS 196.600 to 196.655) to 196.905 (Applicability); and*
>
> *(b) __**Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation**__.*
>
> *   *   *   *
>
> *3) In determining whether to issue a permit, the director __**shall consider all of the following**__:*
>
> *(a) __**The public need**__ for the proposed fill or removal….*
>
> *   *   *   *
>
> *(e) Whether the proposed fill or removal conforms to sound policies of conservation and __**would not interfere with public health and safety**__.*
>
> *   *   *   *
>
> (Emphasis added)

OAR 141-122-0020 Policies

5) The Department ***will not grant an easement*** *if:*

(a) As a result of its circulation for public comment of the application for easement as described in OAR 141-122-0050(3) it determines that ***the proposed use or development would unreasonably impact uses or developments proposed or already in place within the requested area****; ...*

(Emphasis added)

The Southwest Oregon Regional Airport in North Bend is a key part of the Coos Bay area's transportation system that is **already in use**. United Airlines flies to San Francisco daily. United also offers a seasonal flight to Denver on Wednesdays and Sundays from June 10th to October 3rd.[55] The airport also continues efforts to also secure Portland air service.[56]

The Coos Bay Navigation Channel is located here between the North Spit and the end of the East/West runway of the Southwest Oregon Regional Airport. OTH

Photo below – Private jets facing north are lined up at Coos Aviation in Sept of 2015. The Bandon Dunes World Renowned Golf Course brings in a lot of private planes like this to our area.

[55] https://cooscountyairportdistrict.com/faq/

[56] https://cooscountyairportdistrict.com/airport-continues-efforts-to-secure-portland-air-service/

The proposed Jordan Cove project would unreasonably negatively impact the Southwest Oregon Regional Airport and likely cause loss of federal dollars that the airport depends on in order to maintain operations.

49 CFR § 193.2155 - Structural requirements.

*   *   *   *

> ***(b)*** *An LNG storage tank must not be located within a horizontal distance of one mile (1.6 km) from the ends, or 1/4 mile (0.4 km) from the nearest point of a runway, whichever is longer. The height of LNG structures in the vicinity of an airport must also comply with Federal Aviation Administration requirements in 14 CFR Section 1.1.*

Jordan Cove's *Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic Coos Bay, Oregon*, Prepared by KSEAS and Amergent Techs (February 2007) that was filed in with Jordan Cove's September 2017 application (RR #13 part2) to the FERC shows the 1 mile distance on page 163 of the report, which clearly includes the airport runway:

Jordan Cove Energy Project, L.P.

JORDAN COVE ENERGY PROJECT

SUITABILITY OF A WATERWAY FOR
LIQUEFIED NATURAL GAS (LNG) MARINE TRAFFIC

2. Zone 2: The area with less severe consequences than Zone 1 and is considered to extend from 500 meters (0.3 miles) to 1,600 meters (1 mile) for an intentional breech of an LNG carrier. The maximum extent of Zone 2 is one mile or .87 nautical miles.

FIGURE 41 - ZONE 2 OVERLAY (1 MILE RADIUS) OF JORDAN COVE ENERGY

Electronic page 107 of Jordan Cove DSL application states:

> ***6.2.3 Access and Utility Corridor***
> *An approximately 1-mile-long permanent access and utility corridor* ***will be constructed between Ingram Yard and the South Dunes site*** *to provide a conduit for the underground feed gas supply to the LNG Terminal and a number of underground utilities, as well as a location*

for permanent aboveground facilities, including fire water storage tanks for the LNG Terminal and the Fire Department facility. (Emphasis added)

A utility corridor on top of proposed fill may not necessarily be an increased airport hazard but a high-pressure/high-volume hazardous natural gas pipeline with its significant hazard zone would be an increased hazard since it would cross the approach surface overlay of the South West Oregon Regional Airport. The proposed Pacific Connector Gas Pipeline hazardous zone would extend out 800 to over 1,000 feet from the center of the proposed pipeline. **It would NOT be acceptable to locate a hazardous pipeline such as this in the approach surface of the airport runway.** This hazard must be dealt with by someone outside of the local planning jurisdiction since the Coos County Planning Department has not been addressing this hazard.

Jordan Cove is proposing that large volumes of LNG be stored in two (2) full-containment LNG storage tanks, each designed to store 160,000 cubic meters of LNG, along with LNG ships that would be transiting our narrow harbor capable of storing up to 148,000 cubic meters. LNG tankerships would pass within feet of the end of the airport runway and the two storage tanks are located within a mile of the runway. **This would NOT be in the public interest and violates safety recommendations for the safe siting of LNG ports and jetties.**

Planes also do not always fly down the centerline of the runway approach surfaces, as one can see in the photo below (looking across the Coos Bay towards the North Spit and Jordan Cove's property on Sept 20, 2014). Perhaps this planes direction was due to a missed approach or maybe it was just due to people doing some sightseeing along our Oregon Adventure Coastline.[57] A lot of people do that here.

[57] http://www.oregonsadventurecoast.com/

COOS BAY AREA FOG

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 18:

> ***4.1 Weather***
> *4.1.1 Fog*
> *The area is subject to fog conditions very similar to many west coast ports. Fog can be found anywhere within Coos Bay and its tributaries. Fog occurs mostly during summer and fall though is known to occur during other seasons too.*

Photos below are looking from the City of North Bend to the North at the Roseburg Chip Facility on the North Spit across the Bay from the Southwest Oregon Regional Airport.

July 30, 2014 - 10:00 a.m.

The same area July 30, 2014 - 2:00 p.m.

Photos below are looking from the City of North Bend to the North across the Southwest Oregon Regional Airport Runway at the proposed area for the Jordan Cove LNG Export facility that includes the proposed LNG marine terminal, liquefaction trains and two 255 foot high LNG storage tanks.

July 30, 2014 - 10:00 a.m.

The same area July 30, 2014 - 2:00 p.m.

Coos Bay area fog comes on rapidly and sometimes unexpectedly. Thermal heat plumes that would be coming from the proposed Jordan Cove facility would only increase this problem by causing even more fog clouds to form on cold days. **This increased hazard is not acceptable.**

JORDAN COVE'S THERMAL PLUMES

According to Jordan Cove's application they plan on liquefying a maximum of 7.8 mtpa (1,077 MMscf/d) of LNG production net, after deduction for Boil-Off Gas (―BOG") generation.[58] This requires an entirely different process from importing LNG that is considerably more hazardous. Liquefaction Trains that are currently proposed as a part of the Jordan Cove LNG Export facility would emit enormous amounts of heat into the atmosphere. This would contribute to thermal plumes and additional fog in the area. **This would create additional hazards to both navigation in the Bay and to the operation of the South West Oregon Regional Airport**.

Jordan Cove DSL application on electronic page 257 states:

> *The Black & Vetch PRICO® Process, which utilizes five liquefaction trains to produce 7.8 mtpa of LNG, was selected as the preferred technology and is described as part of the proposed Project in Resource Report 1*

Jordan Cove's Revised Sept 2017 RR#1 page 20 states:

> *The PRICO® LNG technology (see Figure 1.3-4) utilizes a single mixed refrigerant (―SMR") circuit with a two-stage compressor and a brazed aluminum refrigerant exchanger. The dry treated gas from the gas conditioning train is divided equally among the five liquefaction trains. In each liquefaction train, the dry treated gas stream flows into a refrigerant exchanger where it is turned into liquid by cooling it to approximately -260oF with the mixed refrigerant. The refrigerant exchanger consists of multiple brazed aluminum heat exchanger cores arranged in parallel inside a perlite insulated cold box.* ***An aerial cooling system (fin-fan) rejects heat from the mixed refrigerant that is gained from the liquefaction of feed gas and compression****. The cold box is purged with nitrogen gas to prevent moisture intrusion and eliminate the potential for a flammable atmosphere inside*

In with Jordan Cove's Application to the FERC filed on Sept 21, 2017[59] under Resource Report #13 Part 2 - JCEP RR13 Public 2 of 7.PDF [39 MB] is a Gexcon report entitled, ―*Facility Siting Hazard Analysis for the Jordan Cove Energy Project*.

The diagram below is from electronic page 696 (Page 9 of 115 of Gexcon report dated 8-28-2017):

[58] Jordan Cove Revised Draft Resource Report #1 page 20. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20181116-5198
[59] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20170921-5142

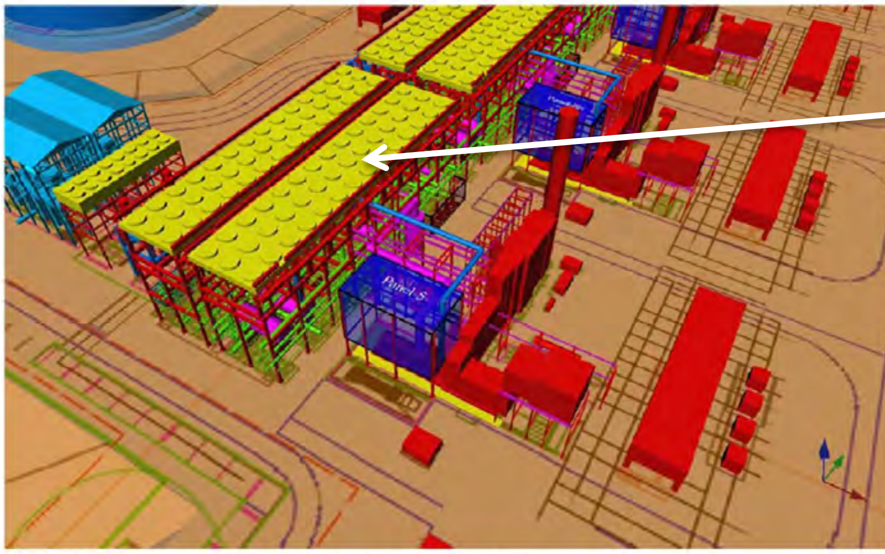


Figure 3. FLACS 3D geometry model of a PRICO liquefaction train.

These circular Lego looking shapes on the top of these childlike drawings of Jordan Cove's proposed liquefaction trains are in fact arrays of axial fans that would operate by pulling air from near ground level to flow through the pipe racks and discharge the hot air (thermal plumes) upwards and into the local atmosphere.

The liquefaction train implements air coolers whose purpose is to extract heat from the refrigerant and discharge it to the atmosphere. The air coolers consist of arrays of axial fans mounted on top of the main refrigerant piperacks. They operate by pulling air from near ground level to flow through the coolers and then discharge it upwards; as such, they generally contribute to the dilution of dense vapor clouds that migrate underneath the fans. However, the simulations included in this report were conservatively run by neglecting the ventilation introduced by the air coolers.

In an updated Gexcon Report Jordan Cove filed with the FERC on November 11, 2018, Gexcon has changed the wording under this diagram for reasons which are not entirely clear. In any event this does not change the hazard. The Diagram below is from page 9 of 112 Gexcon report dated 9-24-2018 filed with FERC 11-16-2018 [60]

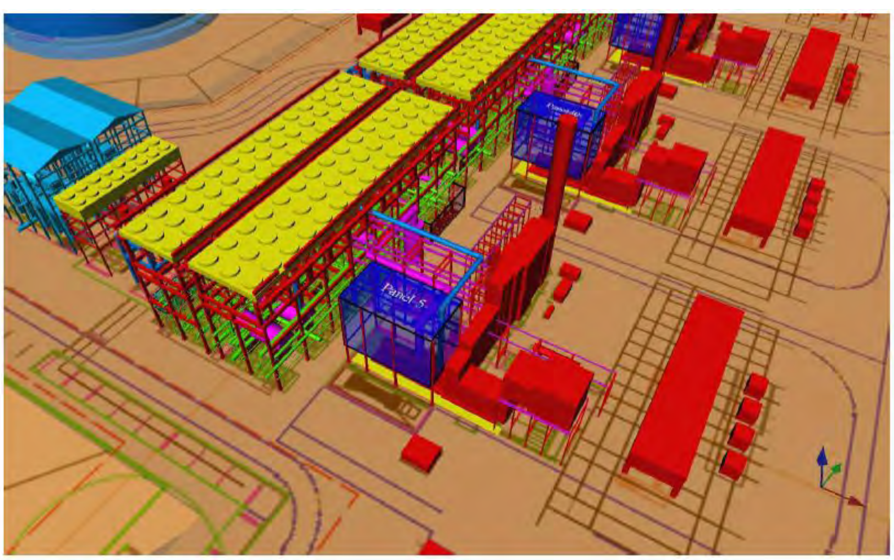


Figure 2-3. FLACS 3D geometry model of a PRICO liquefaction train.

The liquefaction train implements air coolers, the purpose of which is to extract heat from the refrigerant and discharge it to the atmosphere. The air coolers consist of arrays of axial fans mounted on top of the main refrigerant piperacks. They operate by pulling air from near ground level to flow through the coolers and then discharge it upwards; as such, they generally contribute to the dilution of dense vapor clouds that migrate underneath the fans. These dilution effects were included in the FLACS modeling, but only for scenarios that originate from a single liquefaction train in operation. Furthermore, only the fans on that operating train were assumed to be running. Scenarios that do not depend on a liquefaction train running did not include fan dilution effects in the FLACS model.

[60] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20181116-5198

Jordan Cove Energy Project's prior Hazard Analysis Report (GexCon-13-P65569-R1) clearly showed the air cooler placement on top of the liquefaction trains (page 14 and 15): [61]

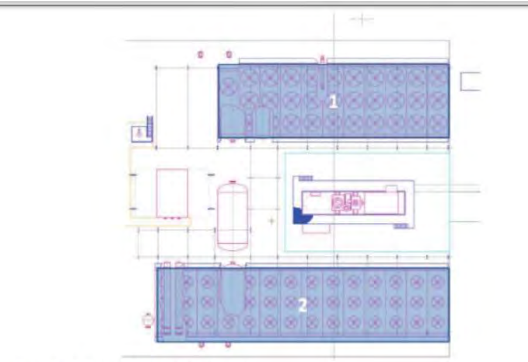


Figure 9. Liquefaction train air cooler arrays.

Table 5. Total air flow rates for each air cooler array (as grouped in Figure 9).

Air Cooler Array	No. of Bays	Total Air Flow Rate (SCFM)
1	11	4.34E+06
2	15	5.64E+06

> ***The PRICO liquefaction trains include air coolers whose purpose is to extract heat from the pipes carrying the refrigerants and discharge it to the atmosphere****. The air coolers consist of arrays of axial fans mounted on top of the main refrigerant piperacks (as labelled in Figure 3); they operate by pulling air from near ground level to flow through the pipe racks and then discharge it upwards. For simulation purposes, the air coolers are grouped in two arrays for each train, as outlined in Figure 9. The total air flow rates for the two air cooler arrays were calculated from data provided by B&V and are listed in Table 5.* (Emphasis added)

> ***The air coolers will be operating continuously while the train is active****;* ***they will continue running until they are stopped by operator intervention; this is to ensure that the refrigerant in the pipes is cooled even following the shutdown of the liquefaction process****, thus preventing pressure buildup in the refrigerant lines. Therefore, the vapor dispersion simulations from liquefaction process releases were performed assuming that the air coolers within the same train as the release would be operational for the duration of the release. The air coolers in the other trains were conservatively assumed not to be operational. The air cooler arrays were subdivided into a reduced number of ―FAN" sources in the FLACS simulations, uniformly distributed across the two air cooler arrays. The total volumetric flow rate of air through the FLACS fans in each array was approximately equal to the total flow rate for that array, as listed in Table 5.* (Emphasis added)

On January 21, 2015, the FAA put out a Memorandum concerning a *―Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations."* [62] (***See Exhibit*** 34)

Pilots in Troutdale, Oregon, have pointed out the hazards of such ―heat" plumes in front of airport approach surfaces. An article that came out on April 22, 2015 in the Willamette Week entitled, *―Hot Air*" stated the following: [63] (***See Exhibit 35***)

> *…Initially, pilots worried that a power plant at Troutdale would hamper visibility. Gas-fired generating plants work by boiling water to produce steam that drives turbines. When the water is cooled, the steam roiling out of the plant's cooling towers could fog pilots' flight paths and create a hazard.*

[61] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130919-5169
[62] https://www.faa.gov/airports/environmental/land_use/media/Technical-Guidance-Assessment-Tool-Thermal-Exhaust-Plume-Impact.pdf
[63] http://www.wweek.com/portland/article-24594-hot_air.html

But the bigger concern now is heat.

Earlier this year, the Federal Aviation Administration directed Troutdale users to an independent consulting firm to analyze the potential impact of the invisible plume of hot air that the combustion of gas by the plant would produce.

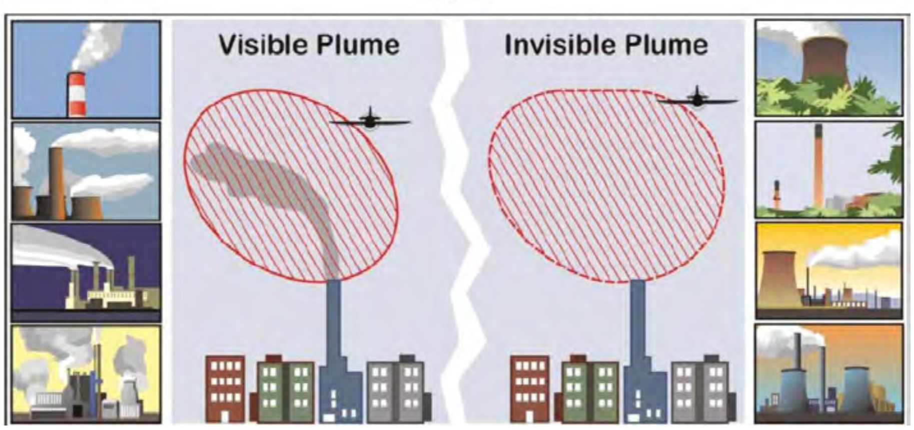
―You're putting a known but invisible hazard right into the path that pilots using Troutdale must fly," says Mary Rosenblum, a Canby resident and president of the Oregon Pilots Association.

Rosenblum says modeling shows the plume could suddenly lift one wing and flip a plane upside down.

―This would happen when the plane is 1,000 feet or less off the ground," Rosenblum says. ―At that altitude, you cannot recover."

The FAA consultant's initial analysis in March found that the invisible plumes could cause as many as a dozen planes to lose control and crash annually—with fatal consequences. A second run of the same model earlier this month found it could happen even more often. *Risk modeling done for the Troutdale Energy Center in 2013 found no such danger….* (Emphasis added)

FIG 7-5-2
Plumes



(***See Exhibits 36 and 37***)

The top of the 160,000 cubic meter LNG tank is very vulnerable as this is where the supply pipeline penetrates the tank for both the transfer of LNG and capture of boil off gases. Dr. James Venart raised issue with the fact that a worst case scenario tank top fire hazard had not been sufficiently analyzed in the hazard analysis of the Jordan Cove LNG Export project. The potential hazards would be far worse than what has been estimated by Jordan Cove. There is no comparison between a plane hitting a tree as has been previously suggested by Jordan Cove's consultants and a plane hitting a 160,000 cubic meter storage tank full of liquefied natural gas. A tree does not have the ability to cause cascading failures that could lead to some 17, 000+ people, who live, work and recreate in Jordan Cove's acknowledged hazardous burn zones, from being severely burned and/or killed.

Shanghai Wuhaogou LNG Expansion Project two new 50,000 m3 LNG storage tanks.

In an interview with Steve Curwood on NPR radio that aired in April of 2005, Robert (Bud) MacFarlane, former national security advisor to President Reagan and James Woolsey, former director of the CIA under the Clinton administration stated the following:

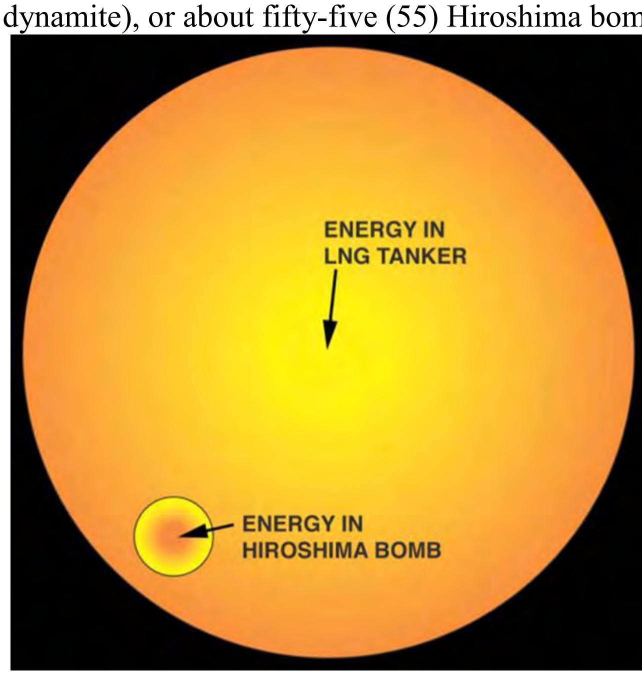
> *CURWOOD: Just to be clear, how vulnerable is vulnerable when you say that there are parts in the Persian Gulf that could be easily disrupted by a terrorist? How easy?*
> *WOOLSEY: Well, let me use only an illustration from Bob Baer, a former CIA officer that's written a book called, "Sleeping with the Devil," in which the opening scenario is a terrorist crashing a 747 into the sulfur cleaning towers up near Ras Tanura in northeastern Saudi Arabia. Since you have to get sulfur out of the Saudi oil that would take several million barrels, probably around five or six million barrels a day, off line for a year or more. And Bud here is an old artilleryman. He and I were talking the other day; I think he'll tell you you probably don't need a big 747 to do that. A pretty skilled guy with some orders could probably do it.*
> *CURWOOD: So, Bud MacFarlane, now the national security aspect of this?*
> *MACFARLANE:* ***Well, as Jim said, I was an artilleryman for 20 years and I can tell you with high confidence that I would have no problem at all in shutting down Ras Tanura on any given afternoon. Four-point-two inch mortar can go 4,000 yards very accurately and the ability of an Al-Qaeda terrorist to come within that distance is easy. There are other threats through shipping, through pipelines that are terribly vulnerable, easy targets and virtually impossible to defend. So, in short, back in the _70s we didn't have a declared enemy with that kind of capability, but today we do****....*[64]
> (Emphasis added)

Tom Bender, myself and several other citizens expressed concerns specific to this issue under FERC submittals 20150113-4002; 20141211-5046; 20141212-5017; 20141218-5046;

[64] http://loe.org/shows/segments.html?programID=05-P13-00013&segmentID=4

20150217-5145; among many others. **Accidental or intentional airplane crashes or dropping a fuel-air bomb would be virtually impossible to prevent or mitigate.**

According to a study called *Brittle Power, Energy Strategy for National Security*, originally prepared for the Pentagon, should the unthinkable happen, the energy content of ONE standard 125,000 cubic meter liquefied natural gas tanker, is equivalent to .7 megatons of TNT (that's 1.4 billion pounds of dynamite), or about fifty-five (55) Hiroshima bombs.



The gas industry March 2006 Cabrillo Port Liquefied Natural Gas Deepwater Port Revised Draft EIR determined that: (on page 4.2-38)[65]

[65] http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13982605

For the worst credible intentional or accidental event release of 53 million gallons (200,000 m^3) from two tanks of LNG, it was determined that a wind speed of 2 m/s (4.5 mph) resulted in ***the worst case in which the flammable vapor cloud extended about 6.3 NM (7.3 miles or 11.7 km)*** *downwind from the FSRU….*
(Emphasis added)

This would NOT BE IN THE PUBLIC INTEREST

NEGATIVE IMPACTS ON TOURISM - RECREATION – FISHING

Tourism spending accounted for 3,300 jobs in Coos County in 2017[66]. Those jobs would be negatively impacted as would also jobs in fishing, clamming, crabbing and oyster growing.

The Jordan Cove FERC Final EIS under Docket CP13-483-000 et al states on page 4-737:

> *According to a 2008 study by the Oregon State Marine Board (OSMB), recreational boaters in Coos Bay took a total of 31,560 boat trips the previous year. Nearly 90 percent of the boat use days involved fishing (including angling, crabbing, and clamming), 9 percent was for pleasure cruising, and the remainder was for sailing and water skiing. Sixty-eight percent of the boating activities in Coos Bay originated from the Charleston Marina and the Empire ramp, 19 percent at the California Avenue boat ramps, and 4 percent at the North Spit ramps.*

In the photo below, boats line the harbor during fall fishing runs on a sunny September afternoon in the lower Coos Bay in front of the area of the proposed LNG terminal. Recreational fishing is a big industry here with lots of events centered on the sport that go on throughout the year. ***See Exhibit 38*** for an example of one such event.

[66] http://www.deanrunyan.com/doc_library/ORImp.pdf

According to Roy Elicker, director of the Oregon Department of Fish and Wildlife —In the coastal counties up to 20 percent of the total net earnings in those counties come from fisheries ... commercial fisheries, in particular." [67]

Project Would Negatively Impact Current Coos Bay Estuary Dependent Industries.

Kayaking in Coos Bay has increased in recent years.

The proposed site of the Jordan Cove LNG terminal, seen here in the background, would border a National Recreation Area.

Terrestrial wildlife may not lose significant amounts of habitat in acres with the project. However, it is wrong to conclude their displacement to other areas is non-impacting. We take exception to the statement that the South Slough would not be impacted. Waterfowl and shorebirds and their natural cohorts displaced by construction or disturbed by vessel operations in the estuary will move away, likely to the South Slough. Displaced human uses such as clamming, crabbing, wildlife observation, fishing, and hunting would likely move these activities and conflict with the existing human uses in that area. Displacement of tourist activities could actually thwart future visitation numbers, negatively affecting the local economies.

Many local industries depend on a healthy bay and estuary. The Coos Bay Estuary currently supports many different types of industries such as fishing, crabbing, oyster growing, clamming, wildlife observation, shipping of wood and other products, recreation, tourism, etc. These all work in

[67] *Wildlife officials confirm economic position of coast's fishing industry* By Steve Lindsley, The Umpqua Post Aug 25, 2014; https://theworldlink.com/news/local/wildlife-officials-confirm-economic-position-of-coast-s-fishing-industry/article_aa056b02-2c7b-11e4-adb5-0019bb2963f4.html

conjunction with one another. The proposed Jordan Cove LNG export terminal appears to have impacts that would be a vast deterrent from that trend.

A report prepared for the Oregon Department of Fish and Wildlife listed the following estimates of expenditures for Fishing, Hunting, Wildlife Viewing, and Shellfishing in Coos County and Oregon in 2009[68]:

Coos County Local Recreation Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$904,977	2.90%	N/A
Fishing	$2,551,433	3.30%	N/A
Wildlife Viewing	$1,637,158	4.90%	N/A
Shellfishing	$1,080,963	20.60%	N/A
Total	$6,174,531	4.20%	N/A

Coos County Travel-Generated Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$2,534,940	2.40%	1.40%
Fishing	$12,253,254	4.60%	6.70%
Wildlife Viewing	$14,110,950	3.10%	7.70%
Shellfishing	$4,552,379	14.70%	2.50%
Total	$33,451,523	3.90%	18.30%

Birds swim just off of tidal sand areas at low tide and several

[68] “Fishing, Hunting, Wildlife Viewing, and Shellfishing in Oregon - *2008 State and County Expenditure Estimates*”; Prepared for the Oregon Department of Fish and Wildlife - Travel Oregon; DeanRunyan Associates; May 2009 http://www.dfw.state.or.us/agency/docs/Report_5_6_09--Final%20%282%29.pdf

species leave footprints in the wet tidal sands where the LNG slip dock is proposed to be built.

According to the World Newspaper; Monday, November 02, 2009:

> ―*Coos Bay got a bit of a tourism boost over the last several days,* ***as 200 or so birders came to the bay to see a rare brown booby that is hanging out near Charleston.*** *People came to scope out the tropical bird from places including Eugene, Portland, Bend, McMinnville, Coos Bay and Washington. The rare tropical bird showed up last week and is the fourth verified sighting of this species of bird in Oregon. The last local sighting was in October 2008, when a dead female washed ashore at Lighthouse Beach."*[69]

The Weyerhaeuser site is arguably one of the best birding destinations in Coos County and attracts a multitude of breeding, migrant and vagrant species year-round. There are species like Wilsons Phalarope and Ring necked Duck. This is a crucial stop-over location for shorebirds during migration where they can rest and refuel, building fat reserves to last them on the next leg of their migration flight. Oregon has lost much of its shorebird habitat through urban development and filling in wetlands and this site is one of the last significant ―refueling stations" left on the Oregon Coast. Shorebirds by the thousands feed in late summer and fall here.

There are many efforts currently underway in Oregon to restore flow restoration priorities for recovery of anadromous salmonids in Coast Basins.[70] (***See Exhibit 39***) The Jordan Cove / Pacific Connector project would be counterproductive and in fact detrimental to these efforts. This is an important issue to both commercial and recreational fishermen on the South Coast of Oregon. Recreational boaters average about 31,560 trips per year in Coos Bay, the majority of which are for fishing. (FEIS under CP13-483 page ES-11) **Total direct visitor travel spending in Coos County has gone from $95.8 million in 2009 to $271.1 million in 2017**.[71]

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[69] ―***Flocking to see a rare bird***"; The World Newspaper; Monday, November 02, 2009 http://www.theworldlink.com/articles/2009/11/02/news/doc4aef7304e1c5b861714126.txt

[70] South Coast Basin – Rivers and Streams – Flow Restoration Priorities for Recovery of Anadromous Salmonids in Coastal Basins -; http://nrimp.dfw.state.or.us/nrimp/information/streamflow/17southcoast/17stream.pdf

[71] http://www.deanrunyan.com/ORTravelImpacts/ORTravelImpacts.html# and http://www.deanrunyan.com/doc_library/ORImp.pdf

FEIS under CP13-483 page 4-734 states:

> *The ODNRA* [Oregon Dunes National Recreation Area] *contains the largest expanse of coastal sand dunes in North America, as well as a coastal forest and over 30 lakes and ponds. Recreational opportunities at the ODNRA include OHV use, hiking, camping, horseback riding, angling, canoeing, sailing, waterskiing, and swimming.*

Photo to Left:
People clamming at low tide in the Lower Coos Bay along Cape Arago Hwy.

Photo to Right:
Evidence of Clams in the tidal areas where the LNG slip dock is proposed to be built.

FEIS under FERC Docket CP13-483 page 4-827 states

> *DIA study by the COE in 2002 found that recreational marine activities along the Oregon coast and river ports generated $42 million in personal income and supported 1,700 jobs. This included spending on marina rental slips, boat ramp users, and other visitors to ports in Oregon. It was estimated that 735,000 party days a year resulted in $79 million in trip spending in the state (Chang and Jackson 2003). In the South Coast (Coos and Curry Counties), 106,000 saltwater fishing trips were counted in 2008, with $8.4 million in expenditures in Coos County. The OSMB counted 32,774 recreational boat fishing trips in Coos Bay in 2007. Ocean recreational fishing for salmon out of Coos Bay generated $693,000 in 2012 (The Research Group 2013a).*

Please consider these vital industries which will be negatively affected when making your decisions.

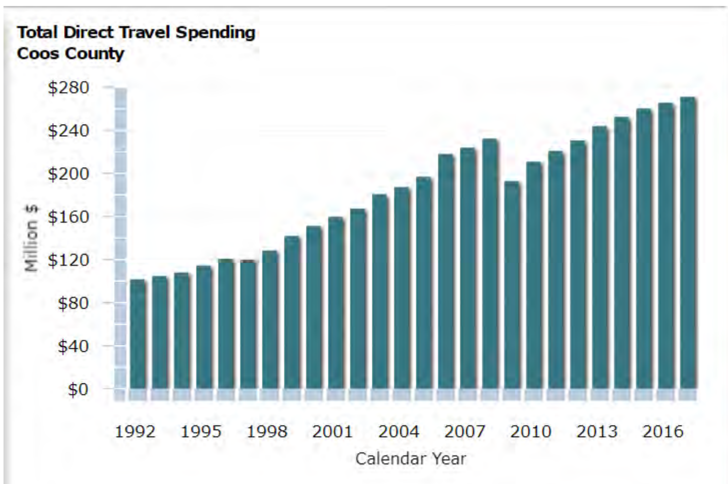
The FERC 2015 Final EIS states that there would be ballast water impacts in the estuary from Jordan Cove's LNG ships which would have their engines running the entire time they are in Port (***See Exhibit 40***). This would negatively impact not only the estuary but surrounding habitat and shorelands, along with recreation.

Jordan Cove states in the Sept 2017 RR#2 page 26

> *…The discharge velocities for the ballast water are low enough that it is not anticipated that any larger organisms (fish, marine mammals, and reptiles or amphibians) will be adversely affected by the ballast discharge. Some smaller organisms may be temporarily displaced by the discharge flow, but the displacement should be negligible in the confines of the slip.*

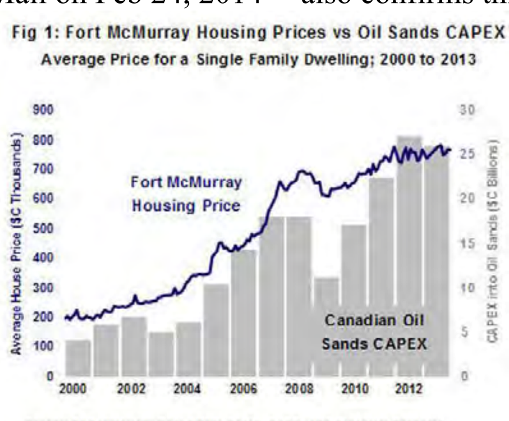
This is not a reasonable assumption. Ignoring the potential invasive species problem and the warming of the water in the lower bay due to the release of ballast water from LNG ships will not make these problems go away.

Dean Runyan has reported the following for Total Direct Travel Spending since 1991 and as you can see it has gone up almost every year. [72]



In Oct of 2007 Sunset Magazine listed the North Spit as one of the top 10 Beach Strolls (***See Exhibit 41***). In September 2008 the National Geographic listed Coos Bay as one of the top 50 places to live. (***See also Exhibit 41***). Jordan Cove would damage those remarkable attributes about our special area which would greatly harm recreation and tourism dollars coming into the area.

Housing and rent prices in the Coos Bay Area would most definitely go up as they have done in other areas. **This would not be in the public interest.** The following graph published in the Globe and Mail on Feb 24, 2014 [73] also confirms this to be the case:



[72] http://www.deanrunyan.com/index.php?fuseaction=Main.TravelstatsDetail&page=Oregon

[73] *Fort McMurray's house prices vs. capital spending in the oil sands*
Special to The Globe and Mail; Published Monday, Feb. 24 2014
http://www.theglobeandmail.com/report-on-business/fort-mcmurrays-house-prices-vs-capital-spending-in-the-oil-sands/article17066573/?from=17066648

Pollution / GHG / Ocean Acidification / Domoic Acid Impacts

Increased LNG Shipping Impacts would not be in the Public Interest.

Increased volumes of LNG being exported would mean increased volumes of actual shipments. DEQ representatives stated at a February 18, 2015 public meeting held in Coos Bay, Oregon, that the **LNG ships were not a part of their permit analysis**.[74] Despite this statement, Jordan Cove's LNG ships and all their necessary support vessels would contribute to a significant additional air pollution impact on local residents in the North Bend/Coos Bay area and would also contribute to an increase in the risk of LNG hazards to our area. Jordan Cove has totally downplayed these impacts and the information found in the Oil Change International report (***See Exhibit 55***), despite the fact that particulate pollutants from the life cycle impact of the Jordan Cove LNG export project would increase respiratory and immune health problems in the local community. Children and elders are especially at risk.[75] Many people have moved here to get away from such impacts. A local (now retired) medical doctor who specialized in allergies has submitted several letters over the years expressing his concerns with Jordan Cove's air particulates and the affect it would have on the local population here. Those particulates would increase with increased export volumes.

Increased Impacts on Shellfish / Food Production / Greenhouse Gasses / Domoic Acid would not be in the Public Interest

Increasing LNG export volumes would increase lifecycle greenhouse gas (GHG) emission volumes as a direct result of the LNG project. This would contribute to increased planet warming impacts, increased droughts, wildfires and ocean acidification. Droughts have already negatively affected our U.S. west coast states and our food production.[76] **Ocean Acidification has already cost the Oregon and Washington shellfish industries $110 million, and endangered some 3,200 jobs**.[77] (***See Exhibits 44, 45 and 46***)

George Waldbusser, an Oregon State University marine ecologist and biogeochemist, said the spreading impact of ocean acidification is due primarily to increases in greenhouse gases. Waldbusser recently led a study that documented how larval oysters are sensitive to a change in the "saturation state" of ocean water - which ultimately is triggered by an increase in carbon dioxide. The inability of

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[74] *Oregon DEQ: Jordan Cove pollution estimates not accepted on blind faith - LNG opponents urge DEQ to consider impact of Jordan Cove's projected greenhouse gas emissions;* Chelsea Davis ; The World ; Feb 18, 2015

[75] ● Dr. Joseph T Morgan Oct 9, 2012, testimony concerning pollutants and the JCEP project: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20121018-5150

● ―*An Exploratory Study of Air Quality near Natural Gas Operations*" - Peer-reviewed and accepted for publication by Human and Ecological Risk Assessment (November 9, 2012).
Theo Colborn, Kim Schultz, Lucille Herrick, and Carol Kwiatkowski
http://www.endocrinedisruption.com/files/HERA12-137NGAirQualityManuscriptforwebwithfigures.pdf

[76] ● ―*Drought prompts cuts to farm irrigation in California, Oregon"* Portland, Ore**.** | By Courtney Sherwood
http://www.reuters.com/article/2015/05/15/us-usa-drought-farming-idUSKBN0O02BL20150515

● *Oregon Governor Expands Drought Declaration* **-** Reuters 04/06/2015 By Courtney Sherwood
http://www.huffingtonpost.com/2015/04/06/oregon-drought_n_7014406.html

● *Kitzhaber declares drought emergency for four southern Oregon counties, opens up assistance*
By Bruce Hammond; Feb 14, 2014;
http://www.oregonlive.com/environment/index.ssf/2014/02/kitzhaber_declares_drought_eme.html

[77] *Study outlines threat of ocean acidification to coastal communities in the U.S.*; Feb 23, 2015
http://today.oregonstate.edu/archives/2015/feb/study-outlines-threat-ocean-acidification-coastal-communities-us

ecosystems to provide enough alkalinity to buffer the increase in CO_2 is what kills young oysters in the environment.

> "*This clearly illustrates the vulnerability of communities dependent on shellfish to ocean acidification," said Waldbusser, a researcher in OSU's College of Earth, Ocean, and Atmospheric Sciences and co-author on the paper. "We are still finding ways to increase the adaptive capacity of these communities and industries to cope, and refining our understanding of various species' specific responses to acidification*."
>
> "Ultimately, however, **without curbing carbon emissions, we will eventually run out of tools to address the short-term and we will be stuck with a much larger long-term problem**," Waldbusser added. [31] (Emphasis added)

Researchers and fishermen worry ocean acidification *could* be impacting Dungeness crab life cycles already. Dungeness crab represents the most valuable fishery on the West Coast, generating $167 million[78] in ex-vessel value in California in 2011. Like oysters, Dungeness crabs are a key driver of the fishing industry, so lucrative that many fishermen rely on them to guarantee an annual income. Fishermen have seen increased closures due to elevated levels of domoic acid, directly linked to lower ocean Ph levels as temperatures rise.[79] (***See Exhibit 46***) These closures have been devastating to the fishing industry. As reported on Feb 19, 2018,[80] the industry was already in a volatile state due to the latest start to a crab season most Oregon fishermen have ever remembered. These problems are likely to get worse in the coming decades.

Commercial crabbers in Oregon and California are suing 30 fossil fuel companies, claiming they are to blame for climate change, which has hurt their industry. The Pacific Coast Federation of Fishermen's Associations filed a lawsuit in November of 2018 with the California State Superior Court in San Francisco against gas and oil companies including Chevron and Exxon Mobil. [81] In October, **the Pacific Coast Federation of Fishermen's Associations successfully sued the U.S. Environmental Protection Association to protect salmon and steelhead trout populations in the Columbia River basin from warm water temperatures caused by dams and climate change**. (***See Exhibit 47***)

Researchers have found that **elevated concentrations of CO2 in seawater can disrupt numerous sensory systems in marine fish**. This is of particular concern for Pacific salmon because they rely on olfaction during all aspects of their life including during their homing migrations from the ocean back to their natal streams.[82] (***See Exhibit 48***)

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[78] https://www.psmfc.org/crab/2014-2015 files/DUNGENESS_CRAB_REPORT_2012.pdf
[79] https://newfoodeconomy.org/ocean-acidification-oysters-dungeness-crabs/
[80] http://theworldlink.com/news/local/new-legislation-to-localize-domoic-acid-closures/article_6933a960-59bd-5949-a9cc-c6191ae31de8.html
[81] *Oregon and California crabbers sue fossil fuel companies* Updated Nov 27, 2018 https://www.oregonlive.com/pacific-northwest-news/index.ssf/2018/11/oregon_and_california_crabbers.html
[82] Williams CR, Dittman AH, McElhany P, et al. *Elevated CO2 impairs olfactory‐ mediated neural and behavioral responses and gene expression in ocean‐ phase coho salmon (Oncorhynchus kisutch)*. Glob Change Biol. 2018;00:1–15. https://doi.org/10.1111/gcb.14532 November 2018

NEGATIVE IMPACTS ON OTHER RURAL BUSINESSES

Seneca Jones Timber Company LLC is a family owned company that owns forest land to supply fiber to its sawmill facilities that provides living wage jobs for <u>over 300 employees</u>. This is twice as many jobs as what Jordan Cove is proposing. Their business operations extend and employ a multitude of independent contractors and contribute importantly to the local economies in Lane, Douglas and Coos counties. The proposed Pacific Connector pipeline would affect nearly 2,600 acres of their forest lands that would be negatively affected in several ways by the PCGP. Seneca Jones filed a Motion with the FERC where they have discussed in detail the detrimental consequences on their business from loss of timber, increase in invasive species and wildfires. The potential for invasive species to spread to their property requires mitigation to maintaining tree growing sites and increases their operational costs. (***See Exhibit 49***) Fred Messerle and Sons, along with Yankee Creek Forestry, also explained the many problems with the proposed Pacific Connector Gas pipeline on rural independent timber companies in documents submitted to Coos County under File No. HBCU-10-01. (***See Exhibit 50 and 51***)

Bill Gow, a Rancher and impacted landowner, has also written about multiple problems with the proposed pipeline and what it would do to his working ranch. His business, home and wetlands would clearly suffer harm. (***See Exhibit 52***) More permanent jobs are being put at risk than what the Jordan Cove project is offering. This is a clear violation of:

OAR 141-122-0020 Policies:

*5) The Department **<u>will not grant an easement</u>** if:*

*(a) As a result of its circulation for public comment of the application for easement as described in OAR 141-122-0050(3) it determines that **<u>the proposed use or development would unreasonably impact uses or developments proposed or already in place within the requested area</u>**;* ... (Emphasis added)

PROJECT DOES NOT HAVE INDEPENDENT UTILITY

The Jordan Cove Project does not have Independent Utility as required under 141-085-0565 (3)(a)

141-085-0510 Definitions:

(43) ―Independent Utility" as used in the definition of ―project," means that the project accomplishes its intended purpose without the need for additional phases or other projects requiring further removal-fill activities.

A project is considered to have independent utility if it would be constructed absent the construction of other projects in the project area. Portions of a multi-phase project that depend upon other phases of the project <u>do not have independent utility</u>. Phases of a project that would be constructed even if the other phases were not built can be considered as separate single and complete projects with independent utility. The Jordan Cove project would require a 229 transmission pipeline, channel navigational alterations, a utility corridor, and several mitigation projects, one in another estuarine district. The project also requires substation upgrades, a worker camp, a safety and resource center along with a multitude of other project components. It does not have independent utility.

Jordan Cove's DSL Application on electronic page 676 states:

- *Approximately 38 acres at the Port Laydown site will be utilized for temporary laydown during construction.*

The Oregon International Port of Coos Bay Strategic Plan from July 2015 [83] shows the area of the Port's proposed Oregon Gateway project on electronic page 155:
(Page 27 of 54 BergerABAM, A14.0083.00 Facility Condition Assessment for Strategic Business Plan May 2015)

Photograph reference: Google Earth

Figure 2. North Spit properties

At Electronic page 61 of the Port's Strategic Plan also list the Port's proposed Oregon Gateway Multipurpose / Multimodal Cargo Terminal project:
(Page 48 of BergerABAM, A14.0083.00 Strategic Business Plan July 2015 DRAFT)

Oregon Gateway[a] Multipurpose/ Multimodal Cargo Terminal.	2015 - 2020	TBD	Timing of multipurpose/multimodal cargo terminal depends on Jordan Cove: this site will be used for construction laydown for Jordan Cove project	North Spit

This clearly states that ―*Timing of multipurpose/multimodal cargo terminal depends on Jordan Cove: this site will be used for construction laydown for Jordan Cove project*."

The Port of Coos Bay's budget that was published on May 19, 2017,[84] states on page 9 :

The Department's 2017-18 primary focus will be on:

1. Manage the Coos Bay 204(f) Ship Channel Modification Permitting Project.
2. Safety and Security for Port assets and staff.
3. Conduct evaluation of Port properties and infrastructure within the Bay.

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83 https://static1.squarespace.com/static/569e6f1176d99c4f392858c4/t/58b489d89f74562a52de8425/1488226796269/Strategic+Business+Plan+web.pdf

84 Port of Coos Bay FY 2017/2018 Budget Message by Hans Gundersen, CFO; May 19, 2017 https://static1.squarespace.com/static/569e6f1176d99c4f392858c4/t/594affd4ff7c50974dc3044d/1498087382779/Adopted+Budget+2017-18.pdf

4. ***<u>Support operational objectives for the Jordan Cove LNG project</u>***.
5. *Support permitting for Port projects.*

*The Port Operations Department main project is included in the Special Projects Fund (The Coos Bay Channel Modification Study). Projected expenses are $4.1 million for the upcoming year, and is provided by a combination of State of Oregon grants **<u>and a project reimbursement agreement with the Jordan Cove LNG Project</u>**.* (Emphasis added)

The Port of Coos Bay is stating very clearly that their objectives are to ―*Support operational objectives for the Jordan Cove LNG project*" and while they are doing this, other, more appropriate developments are NOT being supported or helped. All the dollars that come into our area from travel, fishing, crabbing, clamming and recreation are being harmed in this process.

PacificCorp has filed a land use application for a Substation Replacement Project on Jordan Cove‗s property under Coos County File No. ACU-18-050. This obviously is being done for the Jordan Cove project but many people may not even know about it because the application is under PacificCorp‗s name.

REASONABLE PROJECT ALTERNATIVES WERE NOT CONSIDERED

A wide range of alternatives should have been considered and analyzed in a viable EIS process that was completed prior to this application being processed by Coos County. Reasonable Alternatives were detailed in scoping comments submitted to the FERC in July of 2017 (***See Exhibit 53***). The EIS analysis should include a vast array of renewable energy alternatives to the LNG Project,[85] along with alternative pipeline routes, terminal designs and locations.[86]

Why should Coos County allow such an extensive Removal-Fill permit for a project that IS NOT PROVEN TO BE VIABLE or that has not been determined by Environmental Review under NEPA to be the best alternative?

On August 31, 2018, FERC Issued Environmental Schedules for 12 Pending U.S. LNG Terminal Applications.[87] All of the LNG projects affected by FERC‗s August 2018 issuances of regulatory schedules could be a reasonable alternative to the Jordan Cove project. They are listed as: Freeport Train 4 (CP17-470), Port Arthur (CP17-20), Driftwood LNG (CP17-117), Corpus Christi (CP18-512), Texas LNG (CP16-116), Gulf LNG (CP15-521), Rio Grande LNG (CP16-454),

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[85] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20170710-5423:
026FERC_Exb8_100_Oregon_Wind_Water_Solar-by-2050.PDF
026FERC_Exb9_Renewable_Energy_Alternative_Options.PDF
[86] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20170710-5423:
026FERC_Exb20_Braddocks_Power Point Slide #17 to NWPPA.PDF
026FERC_Exb21_Weyerhaeuser_Hunting_Map.PDF
026FERC_Exb22_Alternative_PCGP_Route_Ver1_Weyco.PDF
026FERC_Exb23_Alternative_PCGP_Route_Ver2_Weyco.PDF
026FERC_Exb24_Alternative_PCGP_Route_Ver3_Weyco.PDF
026FERC_Exb25_Alternative_PCGP_Route_Ver4_SoOre.PDF
026FERC_Exb26_Alternative_JCEP_PCGP_Route_Ver5.PDF
026FERC_Exb27_AlternativeJCEPSitingLocation_Ver6.PDF
[87] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180831-3076

Jacksonville Eagle (CP17-41), Annova LNG (CP16-480), Plaquemines (CP17-66), Jordan Cove (CP17-495), and Alaska LNG (CP17-178).

In September the LNG Law Blog published a notice that the Alaska LNG project and Exxon Mobil had signed agreements for Alaska LNG Supplies.[88] According to the press release, the parties anticipate finalizing long-term gas sales agreements to purchase Exxon Mobil‘s share of 30 Tcf of gas from the Prudhoe Bay and Point Thomson units. The Prudhoe Bay field is one of the largest oil and gas fields in North America. The proposed Alaska LNG Project consists of an 800-mile pipeline, a liquefaction facility, and an LNG export terminal, among other things.

Other LNG projects already in the works include the development of the Sempra Energy Energía Costa Azul (ECA) liquefaction-export project in Baja California, Mexico. Sempra Energy announced in November 2018 that they had entered into a Memorandum of Understanding (MOU) that provides the framework for cooperation in the continued development of the Cameron LNG liquefaction and export project under construction in Cameron Parish, La., and the Energía Costa Azul (ECA) liquefaction-export project.[89]

In Oct 2018 LNG Canada announced that its joint venture participants – Shell, Petronas, PetroChina, Mitsubishi Corporation and KOGAS – had taken a Final Investment Decision (FID) to build the LNG Canada liquefaction and LNG export facility in Kitimat, British Columbia.[90]

So why does Pembina, a Canadian pipeline company with no experience in exporting LNG, think they will be able to outmaneuver all these seasoned LNG industry players in a flooded International LNG gas market?

Increasing exports of hydro-fracked Canadian gas would not be in the public interest.

Jordan Cove‘s February 6, 2018 U.S. Department of Energy Amendment Application page 4 and 5 states:

> *JCEP also hereby informs DOE/FE of a change in corporate ownership from what was described in the Applications. On October 2, 2017, Pembina Pipeline Corporation (―Pembina"), a Canadian corporation, acquired 100 percent of the outstanding shares of Veresen Inc.,* ***JCEP‘s parent entity. JCEP is now a wholly owned subsidiary of Pembina****.* (Emphasis added)

For some time now Pembina has been trying to develop a West Coast export facility in order to export Canadian oil and gas products. Pembina‘s CEO Michael (Mick) Dilger has publicly stated that the purpose of their company is to get **Canadian hydrocarbons to the rest of the world**. [91] Dilger feels

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[88] *Alaska and ExxonMobil Sign Agreement for Alaska LNG Supplies* Posted on Sep 12, 2018 https://www.lnglawblog.com/2018/09/alaska-and-exxonmobil-sign-agreement-for-alaska-lng-supplies/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

[89] *Sempra Energy Signs MOU with Total S.A. for LNG Terminal Development* Posted on Nov 7, 2018 https://www.lnglawblog.com/2018/11/sempra-energy-signs-mou-with-total-s-a-for-lng-terminal-development/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

[90] *LNG Canada Announces a Positive Final Investment Decision* Posted on Oct 2, 2018 https://www.lnglawblog.com/2018/10/lng-canada-announces-a-positive-final-investment-decision/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

[91] *Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world* ;By Claudia Cattaneo;

the shorter travel time to Asian markets versus the U.S. Gulf Coast would mean lower transportation costs for its LNG. (***See Exhibit 54***) He has become frustrated by Canada's infrastructure gridlock and sees the U.S. as a way to get Canadian gas and oil projects to Asia. His company would be in direct competition with U.S. Gulf Coast LNG terminals that are already in operation.

In December a joint venture of Pembina Pipeline Corp., Calgary, and Petrochemical Industries Co. KSC (PIC) of Kuwait was announced which involves a proposed 1.2 billion-lb/year grassroots, integrated propane dehydrogenation and polypropylene (PP) complex in Sturgeon County, Alberta, Canada.[92] In November Pembina announced construction of a $260M propane export facility on B.C.'s Watson Island.[93] The facility, which still requires regulatory and environmental approvals, would use rail cars, not pipelines, to transport propane to the facility from Alberta and B.C.. It is expected to be in service by mid-2020. Pembina dropped a proposal in February of 2016 to build a $500 million propane oil terminal in Portland, Oregon, after the City of Portland determined Pembina had not made a strong enough case as it relates to meeting Portland's environmental standards.[94]

The same could be said for the proposed Jordan Cove project. In January 2018, a new report released by Oil Change International, which looked at a full accounting of greenhouse gas emissions, found that the Jordan Cove Project would result in over 36.8 million metric tons of carbon dioxide equivalent (CO_2e) per year.[95] (***See Exhibit 55***) This is some 15.4 times the emissions from Oregon's last remaining coal-fired power plant, the Boardman Coal plant, which is set to be retired by 2020 due to climate and air pollution concerns. When only considering the in-state emissions alone, **the Jordan Cove project would end up being the largest source of greenhouse gas emissions in the state by 2020**. The project would make it impossible for Oregon to achieve Governor Kate Brown's goal to have Oregon's climate reductions line-up with the targets of the Paris Accords, as well as the emission reduction goals enshrined by the Oregon legislature in 2007. The Oil Change Briefing paper found no evidence to support an assumption that gas supplied by the LNG project would replace coal in global markets

The fact is renewable energy is challenging both coal and gas-fired power generation on a cost-of-energy-produced basis. A peer-reviewed study published in the international journal Energy[96] found that LNG exports from the U.S. could raise emissions in destination markets by triggering additional energy demand rather than displacing coal, and by diverting capital from renewable energy development. According to the U.S. Department of Energy, **exporting natural gas from the U.S. to Asia could end up being worse from a greenhouse gas perspective than if China simply built a**

February 16, 2018; http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

[92] *Canada Kuwait Petrochemical advances Alberta PP complex*; By Robert Brelsford – Houston; Dec. 5, 2017; https://www.ogj.com/articles/2017/12/canada-kuwait-petrochemical-advances-alberta-pp-complex.html

[93] *Pembina Pipeline approves construction of $260M propane export facility on B.C. island*; The Canadian Press; November 30, 2017 ; http://calgaryherald.com/business/energy/pembina-pipeline-approves-construction-of-260m-propane-export-facility-on-b-c-island

[94] *Pembina officially pulls away from $500M Portland propane terminal* By Andy Giegerich - Portland Business Journal; Feb 29, 2016 https://www.bizjournals.com/portland/blog/sbo/2016/02/pembina-officially-pulls-away-from-500m-portland.html

[95] *Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing*; Oil Change International; January 2018 http://priceofoil.org/content/uploads/2018/01/JCEP_GHG_Final-Screen.pdf

[96] *US liquefied natural gas (LNG) exports: Boom or bust for the global climate*?; Energy Volume 141, 15 December 2017, Pages 1671-1680; https://www.sciencedirect.com/science/article/pii/S0360544217319564?via%3Dihub

new power plant and burned its own coal supplies.[97] In addition, Oil Change International found that due to wind and solar now being cheaper than coal and gas in many regions, new gas capacity often displaces new wind and solar rather than old coal.[98]

This would not be in the public interest!

The International Gas Union (IGU) reported in their 2018 World LNG Report (***See Exhibit 56 for select pages***)[99] that a record 293.1 million tonnes (MT) of LNG was traded in 2017. This marks an increase of 35.2 MT (+12%) from 2016; while global liquefaction capacity reached 369 million tonnes per annum (MTPA) as of March 2018. Despite a 75.9 MTPA of excess LNG being produced over what was traded, an additional 92.0 MTPA of liquefaction capacity was under construction as of March 2018.

According to the IGU World Gas LNG Report – 2018 Edition page 5:

> *…In engineering progress, the first floating liquefaction (FLNG) project came online in Malaysia, with additional FLNG projects set to come online during 2018 and beyond. Although no new liquefaction capacity had been added in Russia since Sakhalin 2 LNG T2 in 2010, the first train of Yamal LNG achieved commercial operations in March 2018 and* ***is expected to ultimately add 17.4 MTPA of liquefaction capacity****.* (Emphasis added)

Even with an increase of 8.5% a year in export trading capacity (a 5% increase occurred from 2015 to 2016 (13.1 MT) and a 12% increase occurred from 2016 to 2017 (35.2 MT)), it would take 6.7 years for an average 8.5% increase per year (5% + 12% / 2 years = 8.5% average) (75.9MTPA + 92.0 MTPA = 167.9MTPA excess LNG divided by 25.MTPA (293.1 MTPA in 2017 x 8.5% = 25.MTPA yearly increase) = 6.7yr) until the current excess of LNG volumes would likely be absorbed into the international LNG export markets. The current excess of LNG available for export would take until 2024 to be absorbed using these calculations (2018 + 6yr = 2024), and that is _without' the addition of other projects that are currently in the works ahead of Jordan Cove.

For example, in May of 2018 Petronas bought a 25% share of LNG Canada Project a year after it cancelled its own proposed Pacific NorthWest LNG project at Port Edward, British Columbia due to market conditions. Now that the deal is completed, LNG Canada's ownership interests are Shell at 40%, Petronas at 25%, PetroChina at 15%, Diamond LNG Canada (an affiliate of Mitsubishi Corporation) at 15%, and Kogas Canada LNG at 5%.[100] LNG Canada announced in October 2018 that it would go ahead with its $40-billion export facility on the West Coast.[101] Given the players involved,

[97] https://www.washingtonpost.com/news/wonk/wp/2014/06/09/exporting-u-s-natural-gas-isnt-as-clean-as-you-think/?utm_term=.6abe89578728

[98] *BURNING THE GAS _BRIDGE FUEL' MYTH;* Oil Change International; November 2017; This analysis provides five clear reasons why fossil gas is not a "bridge fuel." It shows that even with zero methane leakage, gas is not a climate change solution.;

[99] https://www.igu.org/sites/default/files/node-news_item-field_file/104747-IGU-Book-Final_062818.pdf

[100] *Petronas Buys 25% Share of LNG Canada Project* Posted on May 31, 2018 https://www.lnglawblog.com/2018/05/petronas-buys-25-share-of-lng-canada-project/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

[101] *$40B LNG facility is the light at the end of a long tunnel for Canada's natural gas sector*
Struggling gas industry faces several more years of low prices until new Asia export project is built
Kyle Bakx · CBC News · Posted: Oct 03, 2018 https://www.cbc.ca/news/business/lng-canada-gmp-firstenergy-arc-1.4847377

the LNG Canada west coast LNG project has a far greater chance of development over the Jordan Cove Project. Jordan Cove does not have the financial means necessary to build a greenfield LNG project, nor the experience. Pembina, Jordan Cove's parent company, has already announced that it intends to seek partners for both the pipeline and liquefaction facility thereby reducing its 100 percent ownership interest to a net ownership interest of between 40 and 60 percent. [102]

According to the IGU World Gas LNG Report – 2018 Edition, page 65:

> ***Will LNG Contracting and Liquefaction FIDs Take Shape This Year? Investment decisions on new LNG supply have come to a near standstill over the last two years. In 2017, only one large-scale LNG project reached FID – the 3.4 MTPA Coral South FLNG in Mozambique – marking the lowest volume of sanctioned LNG in nearly twenty years***. *This follows the trend established in 2016, when only two projects reached FID for a combined sanctioned capacity of 6.3 MTPA. This contrasts with the high level of FIDs in 2011–15, when annual sanctioned capacity exceeded 20 MTPA. The slowdown in investments is partly a reflection of the wider trend of cutting back capital expenditure across the oil and gas industry during the commodity downturn, but can also be attributed to the lack of contracting activity from buyers hesitant to sign long-term deals in the face of growing near-term LNG supply.* ***Without long-term contracts, new liquefaction projects will find it challenging to proceed***
>
> ***The total volume and number of LNG contracts signed has declined consistently for the past three years***. *In 2017, only one firm long-term contract was signed that was tied specifically to a proposed project working toward FID (Edison's SPA at Calcasieu Pass LNG), as the majority of deals completed were portfolio contracts (67% of all firm deals signed). The lower total volume of contracts is not only a result of fewer contracts being signed, but is also tied to the trend of smaller volume contracts – the average size of contracts signed has dropped, which means that marketing timelines extend as they seek to fill the entire capacity…*

The IGU World Gas LNG Report – 2018 Edition, page 19 states:

> *Projects planning to reach an FID in the near term are competing for customers willing to sign foundational contracts ahead of the large near-term buildup in supply, leading to a general slowdown in contracting activity over the last several years. Demand uncertainty, capital budget constraints, and a desire for shorter-term contracts are challenges facing project sponsors, many of which are emphasising their cost structures and location-specific advantages in an attempt to move forward.*

The IGU World Gas LNG Report – 2018 Edition, page 26 states:

> *Expectations of a well-supplied market in the near term, greater demand uncertainty, and lower oil and gas prices have reduced the number of FIDs and long-term foundational contracts that have been signed over the past two years. A number of projects were delayed or cancelled in 2016 and 2017 owing to project economics and partner alignment challenges in the current market environment.* ***Given the large number of projects aiming to reach an FID in 2018, further culling of projects is expected***. (Emphasis added)

[102] *Pembina Pipeline Corporation Announces 2019 Capital Program and Guidance;* By Pembina Pipeline Corporation Dec 10, 2018; https://www.prnewswire.com/news-releases/pembina-pipeline-corporation-announces-2019-capital-program-and-guidance-300762358.html

Page 29 states:

> ***Only one US project – Calcasieu Pass LNG – signed a binding long-term contract in 2017, with Italy's Edison. Shell, the project's first customer, signed an SPA for 1 MTPA in 2016 and agreed in February 2018 to purchase an additional 1 MTPA****. Two binding contracts between Cheniere and China's CNPC were also signed in early 2018. In conjunction with a contract signed with Trafigura in early 2018, the deals are expected to support an FID at Corpus Christi LNG T3. The CNPC agreements stem from a memorandum of understanding (MOU) signed last November and* ***are the first long-term deals signed between a US LNG developer and Chinese companies***

The IGU World Gas LNG Report – 2017 Edition[103] stated that there was 879 MTPA of proposed liquefaction capacity, as of January 2017: (page 5)

> *New Liquefaction Proposals: Given abundant gas discoveries globally and the shale revolution in the US, proposed liquefaction capacity reached 890 million tonnes per annum (MTPA) by January 2016. This figure fell slightly to 879 MTPA at end-January 2017 in an attempt at rationalization with market demand.* ***More of these projects will not go forward as demand remains far below this ambitious target****; particularly as ample pipeline supply - by Russia and Norway to Europe, and the US to Mexico - reduce the need for LNG in those markets. Additionally, Egypt will experience a drastic reduction in LNG demand as the Zohr field comes on-line and preferentially supplies the domestic market. In fact, there is potential for Egypt to again be a significant LNG exporter. The areas with the largest proposed volumes include the US GOM, Canada, East Africa, and Asia-Pacific brownfield expansions.*

The IGU World Gas LNG Report – 2017 Edition, page 27 states:

> *Apart from high liquefaction costs, greenfield projects proposed in Western Canada and Alaska require lengthy (300 miles or more) pipeline infrastructure. Integrated Western Canadian projects have announced* ***cost estimates of up to $40 billion****, while in Alaska the estimate was revised downward in 2016 to approximately $45 billion from $45-65 billion previously*

The IGU World Gas LNG Report – 2017 Edition, page 31 states:

> *Eleven[18] projects have now moved through the FERC environmental review process, including four in 2016: Cameron LNG T4-5, Elba Island, Golden Pass, and Magnolia LNG. While there is greater clarity regarding expected timelines and costs, FERC also denied approval of an LNG export project for the first time in 2016.* ***FERC did not approve the 6 MTPA Jordan Cove LNG project and its associated pipeline, citing concerns that the pipeline had not demonstrated sufficient commercial need to outweigh landowner concerns****. After an unsuccessful appeal, the sponsor plans to submit a new application.* ***Most other projects in the continental US do not require significant new pipeline infrastructure and so may be less likely to face the same obstacles****.* (Emphasis added)

[103] https://www.igu.org/sites/default/files/103419-World_IGU_Report_no%20crops.pdf

The IGU World Gas LNG Report – 2017 Edition, page 60 states:

> **How will existing LNG contracts come under pressure in 2017?**
> * * * *
> *Gas demand has slowed quicker than anticipated in some importing markets – particularly in Asia Pacific. As a result, buyers in those countries have to be creative to manage over-commitments.* ***China has been over-contracted since 2015*** *and this may continue in 2017 given the large additions of Australian capacity and associated contracts with the Chinese NOCs. Beyond the NOC's, smaller LNG players in China – e.g., ENN Energy, Beijing Gas, Jovo Group – are becoming more active players.* ***In the same way, other Asian LNG buyers in Japan and South Korea are potentially overcommitted in the near term and many have formed trading businesses to manage their portfolios****.*

INTERNATIONAL MARKET DOES NOT SUPPORT HIGHER LEVELS OF U.S. LNG EXPORTS

There are too many competitors in the international market currently and there is a glut of LNG that will last for many years. Due to this fact a higher level of scrutiny and independent review **is required in order to prevent an overbuild of pipelines and LNG facilities**, particularly when considering the negative impact these facilities can have on U.S. Manufacturing, jobs in other industries, American landowners and rural / low-income communities. The FERC, U.S. Department of Energy and the DSL should fully consider the American public interest and need and not just what is best for corporations who may or may not have the best interest of Americans.

It should be very clear that liquefied natural gas export plans face years of oversupply.[104] In addition, the press reported in August of 2016 that Japan's JERA had plans to cut long-term LNG contracts by 42 percent by 2030.[105]

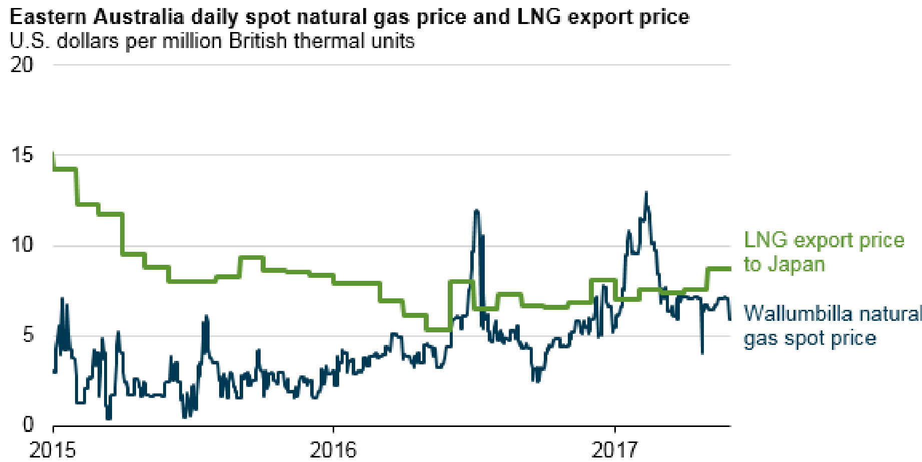
The U.S. Energy Information Administration (EIA) reported on October 20, 2017 in an article titled, ―*Australian domestic natural gas prices increase as LNG exports rise"* that:

> *Australia became the world's second-largest exporter of liquefied natural gas (LNG) in 2015 and is likely to overtake Qatar as the world's largest LNG exporter by 2019.* ***As Australia's LNG exports have increased, primarily from LNG projects in eastern Australia, the country has had natural gas supply shortages in eastern and southeastern Australia and an increase in domestic natural gas prices****...*[106] (Emphasis added)

[104] Liquefied Natural Gas Export Plans Face Years of Oversupply (July 18, 2017) https://www.bna.com/liquefied-natural-gas-n73014461925/

[105] Japan's Jera plans 42 percent cut in long-term LNG contracts by 2030 (August 10, 2016) https://wwwreuters.com/article/us-lng-jera/japans-jera-plans-42-percent-cut-in-long-term-lng-contracts-by-2030-idUSKCN10L117

[106] EIA Australian domestic natural gas prices increase as LNG exports rise Oct 20, 2017 https://www.eia.gov/todayinenergy/detail.php?id=33412#



The EIA October 20, 2017 Report also states:

> *The U.S. experience with growing LNG exports is unlikely to be similar to Australia's.* ***More than half of Australia's total natural gas production was exported in 2016****. Australia's Energy Market Operator expects Australia's LNG exports will account for 80% of domestic production by 2020. Despite the rapid LNG export capacity growth, EIA's latest Annual Energy Outlook 2017 (AEO2017) Reference case—which reflects current policies and regulations—projects U.S. LNG exports to amount to only about 9% of total domestic natural gas production by 2020.* (Emphasis added)

This EIA statement above concerning U.S. impacts is misleading due to the fact that as of April 9, 2018 the U.S. Dept of Energy (DOE) had accepted applications for **LNG export volumes totaling 57.14 Bcf/d to Free Trade Agreement Nations and 54.46 Bcf/d to Non-Free Trade Agreement Nations**.[107] Most of these volumes have already been approved either directly or conditionally.

The U.S. EIA reported in an August 9, 2017 article titled, *United States expected to become a net exporter of natural gas this year* [108] that:

> *Natural gas production in the* ***United States increased from 55 billion cubic feet per day (Bcf/d) in 2008 to 72.5 Bcf/d in 2016****. Most of this natural gas—about 96% in 2016—****is consumed domestically****.* (Emphasis added)

The U.S. EIA was wrong to not consider in their analysis that the U.S. DOE has ALREADY APPROVED LNG Exports in excess of the EIA projected U.S. production and is HEADING THE U.S. FOR WORSE THAN WHAT IS HAPPENING IN AUSTRALIA where unfettered LNG Exports have tripled natural gas prices, harmed domestic consumers and caused manufacturing plants that rely on natural gas to close, throwing people out of work.[109]

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[107] https://www.energy.gov/sites/prod/files/2018/06/f53/Summary%20of%20LNG%20Export%20Applications_0.pdf
[108] EIA *United States expected to become a net exporter of natural gas this year* - August 9, 2017
https://www.eia.gov/todayinenergy/detail.php?id=32412
[109] • *Everyone's a Loser in Australia's LNG Boom* By David Fickling March 26, 2017
https://www.bloomberg.com/gadfly/articles/2017-03-26/everyone-s-a-loser-in-australia-s-lng-boom
• *IECA to Congress: Australians' Gas Bills Soar Amid LNG Export Boom*
(view letter to U.S. House / Senate) October 3, 2014
http://www.ieca-us.com/wp-content/uploads/10.03.14_Australia-LNG-Article_Senate1.pdf
http://www.ieca-us.com/wp-content/uploads/10.03.14_Australia-LNG-Article_House2.pdf

This is NOT IN THE PUBLIC INTEREST.

On July 11, 2017, The Industrial Energy Consumers of America (IECA) President, Paul N. Cicio, issued the following statement following a July 11, 2017 Wall Street Journal story titled ―*How Energy-Rich Australia Exported Its Way Into an Energy Crisis*.‖[110]

> ―*We applaud the Wall Street Journal on their story on how the Australian government failed the public and their manufacturing sector by failing to put consumer safeguards in place. Foreign consumers benefited from LNG exports, while Australian consumers saw natural gas prices skyrocket. Shortages forced power plant outages and manufacturers were forced to cut back production or shutdown. Manufacturers continue to leave the country, resulting in the loss of good paying jobs.*
>
> ―*The U.S. is following the same failed policy. There are no consumer protections in place on U.S. LNG exports. Currently, a breathtaking volume equal to 71 percent of 2016 U.S. natural gas supply has been approved for exports.*
>
> ―*The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2017 forecasts that cumulative demand in 2050, only 33 years away, indicates that 56 percent of all U.S. natural gas resources in the lower 48 states will be consumed. Natural gas is unique and a valuable resource for manufacturing jobs and investment, for which there is no substitute.*
>
> ―***The U.S. still has time to put common-sense consumer safeguards in place now**.‖* [111] (Emphasis added)

On August 16, 2017, the Industrial Energy Consumers of America (IECA) sent a letter to Secretary Perry which outlines how the previous Administration failed to properly conduct public interest determinations on LNG application volumes for export to non-free trade agreement (NFTA) countries, as required under the Natural Gas Act (NGA).[112] On August 22, 2017, the Industrial Energy Consumers requested that the DOE conduct a legal review of this matter.[113] **We continue to stand in**

• *Australian Nitrogen Fertilizer CEO Confirms Unfettered LNG Exports Have Tripled Natural Gas Prices*
April 15, 2014
http://www.ieca-us.com/wp-content/uploads/04.15.14_Australia-Congressional-Communication_Incitec-Pivot.pdf

[110] The Wall Street Journal ―*How Energy-Rich Australia Exported Its Way Into an Energy Crisis*‖
The world's No. 2 seller abroad of liquefied natural gas holds so little in reserve that it can't keep the lights on in Adelaide—a cautionary tale for the U.S. By Rachel Pannett; July 10, 2017
On a sweltering night this February, the world's No. 2 exporter of liquefied natural gas didn't have enough energy left to keep its own citizens cool.
A nationwide heat wave in Australia drove temperatures above 105 degrees Fahrenheit around the city of Adelaide on the southern coast. As air –conditioning demand soared, regulators called on Pelican Point, a local gas –fueled power station running at half capacity to crank up….
https://www.wsj.com/articles/how-energy-rich-australia-exported-its-way-into-an-energy-crisis-1499700859

[111] IECA Press Release ―*WSJ Story Illustrates How Australian LNG Exports Resulted in a Domestic Shortage for Consumers*‖ July 11, 2017 http://www.ieca-us.com/wp-content/uploads/07.11.17_WSJ_Australian-LNG-Story-Press-Release.pdf

[112] Manufacturers Justify LNG Export Approval Moratorium: 58 to 71 Percent of all Natural Gas Could be Consumed by 2050 (view press release) Aug 16, 2017 http://www.ieca-us.com/wp-content/uploads/08.16.17_Perry-Two-Exports-Scenarios-Letter_FINAL.pdf

[113] Manufacturers Request DOE to Conduct Legal Review of LNG Export Applications to NFTA Countries (view press release) Aug 22, 2017 http://www.ieca-us.com/wp-content/uploads/08.22.17_Letter-to-DOE-Legal.pdf

solidarity with the Industrial Energy Consumers of America (IECA) and fully support their urgent request for a legal review. See ***Exhibit 28*** for IECA's January 30, 2019 report, ―*Excessive Liquefied Natural Gas (LNG) Exports to NFTA Countries are not in the Public Interest and Increase Natural Gas and Electricity Prices to Consumers.*"

On March 1, 2018 Reuters reported in an article titled ―*U.S. trade group urges halt to further LNG export applications*"[114]

> *A U.S. manufacturing trade group on Thursday urged the U.S. Department of Energy not to approve further liquefied natural gas (LNG) export applications, citing concerns that* ***the country was consuming and exporting the fuel at a faster clip than it was finding new resources****.*
>
> ***The agency's approval of LNG export volumes equal almost 70 percent of 2016 U.S. demand for periods of 20 to 30 years, which cannot possibly be in the ―public interest****," the Industrial Energy Consumers Of America (IECA) said….* (Emphasis added)

Why on earth would we harm our American manufacturing base like this, not to mention American consumers, property owners and rural and low income communities?

THE U.S. MUST AVOID THE ENERGY MISTAKES OF THE PAST

> ―*Those who cannot remember the past are condemned to repeat it.*" - Philosopher George Santayana

In the 1970's, the Washington Public Power Supply System (WPPSS, aka ―whoops") began the largest nuclear power plant construction project in U.S. history: reactors 1, 2, and 4 at Hanford, and reactors 3 and 5 at Satsop, west of Olympia. By 1983, cost overruns, delays, a slowing of electricity demand growth, concerns over nuclear power, and several other factors, one having to do with geology, led to cancellation of two plants and a construction halt on two others. The agency in the end defaulted on $2.25 billion of municipal bonds, which is still the largest municipal bond default in U.S. history. The monumental court case which followed took nearly a decade to fully resolve. At Satsop, construction was well along on plants 3 and 5, with plant number 3 being about 85% complete, with the reactor in place when the default occurred. **Cooling towers, 480 feet tall, never saw a breath of steam, and demolition costs are estimated to be in the hundreds of millions. Ironically, the energy blackouts predicted by the industry to justify the building of the plants never occurred after the projects were stopped**.

[114] https://www.reuters.com/article/us-lng-tradegroup/u-s-trade-group-urges-halt-to-further-lng-export-applications-idUSKCN1GD6FY

Photo above: Defunct Satsop Nuclear Power Plant sits as an eyesore on the horizon – April 2017 [115]

The New York Times
Failure of Power Project Creates a Blank Canvas[116]
By Carey Goldberg
Published: March 09, 1997

> *—...A colossal white elephant that cost several billion dollars but was never finished, the plant was part of the boondoggle that led to the biggest municipal bond default in United States history, when the Washington Public Power Supply System — known locally as Whoops — defaulted on $2.25 billion in bonds in 1983.*
>
> *The plant has been sitting here in limbo since then — too expensive to tear down, too unwieldy to be bought, too costly to maintain in mothballs forever.* ***<u>There is no demand for the expensive energy it would have produced, and proposals to turn it into everything from a nuclear weapons demolition plant to a theme park have come and gone</u>****...”* (Emphasis added)

The New York Times / Elma Journal
Can Unused A-Plant Become a Princess?[117]
By Jessica Kowal
Published: April 21, 2006

> *—. ELMA, Wash. — The stillborn Satsop nuclear plant,* ***<u>a product of cheap-power fantasies run amok</u>*** *here a quarter-century ago, stands ominously on a hill in this economically depressed corner of western Washington.*

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[115] https://www.youtube.com/watch?v=ZxW7_jPB4CE By marantz2010; Published on Apr 10, 2017
[116] http://www.nytimes.com/1997/03/09/us/failure-of-power-project-creates-a-blank-canvas.html?pagewanted=all&src=pm
[117] http://www.nytimes.com/2006/04/21/us/21nuke.html

<u>Because local officials cannot afford to tear the plant down, they are trying to market their nuclear lemon as job-creating lemonade. Sometimes, though, even they sound doubtful</u> *…."* (Emphasis added)

Clean Energy Development Creates Far More Jobs Than Fracked Gas Developments.

Each dollar invested in clean energy creates two to seven times as many jobs as spending that dollar on fossil fuels.[118] Businesses, elected officials, and community residents in Oregon have been working together to speed our transition to cleaner energy like solar and to greater energy efficiency. The export of fracked gas threatens all the progress we are making.

CUMULATIVE IMPACTS NOT CONSIDERED

Cumulative Impacts with other proposed Projects must be considered.

- Port of Coos Bay dredging proposal for Channel Deepening and Widening involving the removal of 18 mcy of dredge material under Corps review
- City of North Bend California Street Boat Ramp Replacement including dock and piling replacement under Corps 47964 / DSL APP0061371[119]
- City of North Bend Pacific Connector Gas Pipeline application under North Bend File No. FP2-18 and CBE 3-18 and also DSL permits.
- Southport Forest Products LLC / R/F for 5 mooring dolphins adjacent to Barge Berth (Piling, RemFill) / DSL APP0061629[120]
- City of Coos Bay R/F for replacing 498 feet of existing sewer line parallel to Coal Bank Slough. (ErosionCon,Pipeline,RemFill,Util) / DSL APP0061778[121]
- Various other recent DSL projects at www.statelandsonline.com

The Port of Coos Bay channel modification project would include a new vessel turning basin with a designed length of 1,400 feet, width of 1,100 feet, and depth of -37 feet; constructed approximately between River Miles 7.3 to 7.8.

Obviously, the proposed Jordan Cove LNG Export Project would benefit greatly from the Port of Coos Bay's proposed Channel Modification project including the proposed new vessel turning basin. I do not understand, however, why the Port would propose deepening and widening the Coos Bay shipping channel to -45 feet and then develop a turning basin that is only -37 feet. The -37 foot turning basin negates the need for the shipping channel to be any deeper than the -37 feet that it currently

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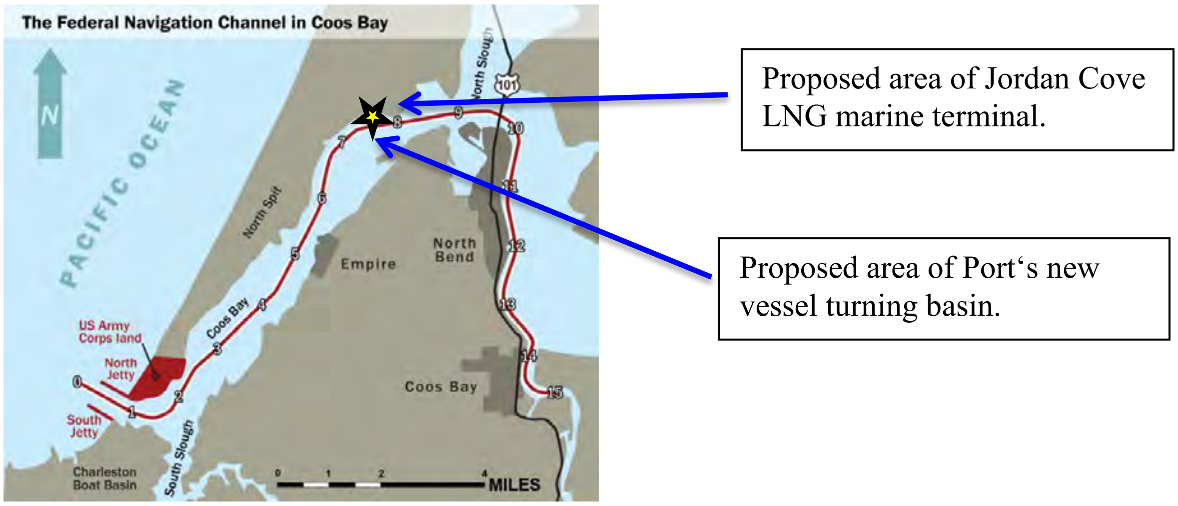
[118] http://www.sightline.org/2016/02/16/why-oregon-needs-the-healthy-climate-act/
[119] http://statelandsonline.com/index.cfm?fuseaction=Comments.AppDetail&id=61371
[120] https://lands.dsl.state.or.us/index.cfm?fuseaction=Comments.AppDetailLF&id=61629
[121] https://lands.dsl.state.or.us/index.cfm?fuseaction=Comments.AppDetailLF&id=61778



Immense Dredging would have Negative Impacts on the Coos Bay and Bay Users.

It is still not clear as to whether the Oregon International Port of Coos Bay and Jordan Cove have made enough dredge disposal site allowance needed for maintenance dredging as was indicated in a June 8th 2009 and an August 18, 2015 comment letter(s) that were sent to the FERC from the United States Environmental Protection Agency, REGION 10, Seattle, WA 98101-3140.[122] (***See Exhibit 58** for the August 2015 letter*.)

TURBIDITY MODELING FLAWED

Jordan Cove did not actually do test of the static tidal action with respect to sedimentation transport; they used computer modeling that is obviously severely flawed. The modeling methodology used by Moffatt & Nichols (the contractor hired to do the modeling) is fundamentally flawed for a number of reasons. The most important reason is they treat Coos Bay as a 2D problem when it is in fact 3D due to vertical variability in temperature, salinity, and sediment concentrations in the water column. This will affect how and where suspended sediment is transported by the currents in the bay, it will also affect the concentration of the suspended sediment.

Their flawed modeling makes it look like the sediments will only go a short distance out from the dredging activity when that would NOT be the case. In addition, deepening of the tidal channels actually increases estuarine circulation and suspended sediment concentration (SSC). **(*See Exhibit 59*)** At what point is a critical amount of dredging performed which raises deposition levels beyond an acceptable criterion? The negative impacts from dredging can sometimes last for many months and even in some cases years (***See Exhibits 60, 61 and 62***)

A covering of less than 50 microns (1/500th of an inch) is enough to impair the attachment of O. lurida larvae to hard substrate. It has long been known that a thin layer of sedimentation impairs the attachment of oyster larvae to hard substrate. According to the U.S. Army Corps of Engineers:
U.S. Army Corps of Engineers (December 1998) "Technical Note DOER-E2: Environmental Windows Associated with Dredging Operations."

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[122] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20090617-0016 and http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150901-0057

—Although a thin layer (several mm) of sediments may not be fatal to adult oysters, it may affect reproduction. Because larval oysters require hard substrata for settlement, the presence of even a few millimeters of sediment covering an oyster reef may inhibit larval recruitment (Galtsoff 1964; McKinney et al.1976).''[123]

Tidal Action in the Coos Estuary is extremely swift. In October of 2014 a construction worker died when he apparently accidentally drove his pickup truck off a work platform at the North Bend McCullough Bridge.[124] His body was found a few hours later some 4 miles from where his truck had entered the water. If a human male body can move that far just from Coos Bay's tidal action, it makes sense to assume that much lighter weight sediments would also move with the swift tidal action in the Coos Bay and essentially would impact the entire estuary. This is another example why independent review by other experts should be brought in by Coos County to confirm these findings being presented by Jordan Cove.

In 1999 Clausen Oysters lost 70 to 75 percent of their oysters when a freighter known as the New Carissa grounded on Horsfall beach about a mile north of the North Spit. The tides brought oil that escaped from the New Carissa into the Coos Bay and in addition to oysters more than 200 birds were killed along with immeasurable damage to local sea organisms. [125] (***See Exhibit 63***)

The Department of Agriculture continually stops oyster harvesting in the bay when certain bacteria levels reach a certain level. It can take anywhere from several days to several weeks for the bay to clear. **Unless appropriate modeling is used it is impossible to make projections of how dredging is going to impact water circulation which affects bacteria levels and how long it takes for it to clear out, among other critical issues**.

Proper testing of tidal muds and dredging soils has also not occurred. Past shipping contaminants including Tributyltin (TBT), arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs) could be re-suspended into the Coos Bay harming marine life and business that depend on that marine life. (***See Exhibit 62***) As far as I can tell there are no plans to test for all these contaminants (See Table 9-2 found on electronic page 524 of DSL application). The Roseburg Chip facility berth was tested in 2009 and TBT was detected above the SL1 in the west part of the berth; discrete re-sampling did not detect TBT but dredging was restricted to the eastern portion of the berth anyway. (See electronic page 1015 of Jordan Cove's DSL application.) So these contaminates ARE there in areas right next to the planned project area and proper testing by an independent analysis has yet to be done.

Coos County should consider carefully the analysis that was done by sedimentation expert Thomas Ravens on Jordan Cove's Vladimir Shepsis's Coast Harbor and Engineering report (***See Exhibit 29***) A properly completed EIS / analysis should not just rubber stamp the industry's data.

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[123] U.S. Army Corps of Engineers (May 2005) "Sedimentation: Potential Biological Effects of Dredging Operations in Estuarine and Marine Environments."

[124] —*Florence man killed in McCullough Bridge accident*" By Kurtis Hair, The World Oct 23, 2014; https://theworldlink.com/news/local/florence-man-killed-in-mccullough-bridge-accident/article_2661e38e-5aca-11e4-8e8e-07378b90963a.html

[125] *Shell shock* , June 14, 2010, By Nate Traylor, Staff Writer - The World https://theworldlink.com/news/local/shell-shock/article_389a9be8-77dc-11df-9127-001cc4c03286.htm

Dr. Thomas Ravens who has been modeling hydrodynamics and sediment transport in estuarine environments for 18 years found serious deficiencies in Dr. Vladimir Shepsis's modeling work. Dr. Thomas Ravens states the following on page 2 of his November 13, 2011 report:

> *―Chapters 10 and 11 of Exhibit 4 (entitled Jordan Cove Energy Project and Pacific Connector Gas Pipeline - Volume 2) present sediment transport calculations which purport to show that sediment transport impacts of the proposed dredging project in Haynes Inlet would have minimal impacts. <u>However, close scrutiny of Exhibit 4 shows that there are serious deficiencies in the methodology employed in the sediment transport modeling. Consequently, the finding that there would only be limited impacts is lacking a solid foundation</u>….*" [126/127] (*Emphasis added*)

Dr. Thomas Ravens goes on to outline in his report the most serious flaws under the following subheadings:

> *1. Use of un-validated sediment transport model to establish background conditions.*
> *2. Assumption of spatially uniform sediment size despite data indicating significant heterogeneity.*[5]

INCREASED LNG VESSEL TRANSITS = INCREASED TURBIDITY

Physical movement of LNG vessels 950 feet in length and 150 feet wide and drafting 40 feet of water will greatly disturb the channel and its physical structure. The two - three 80 ton tugboats pulling or pushing the vessel will cause even more turbidity and erosive wave action.

The LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. [Jordan Cove RR #1 page 25 & 26] **This amounts to 220 to 240 harbor disruptions per year during high slack tides which are also prime tides used currently by other bay users.**

The 240 trips up and down the seven and one-half mile channel that are predicted by the applicant would cause the estuary to become more turbid. According to a study done by the Jordan Cove Energy Project,[128] propeller wash velocities from the LNG vessels and tugs would be of similar magnitude to tidal currents in the navigation channel but the potential propeller wash velocities would be somewhat higher than the typical maximum tidal currents in the channel. Compounding negative effects, such as erosion of intertidal lands and shorelines would continually degrade water quality as vessels moved in and out of the bay. Increases in turbidity would negatively impact aquatic plant life, shellfish, and benthic organisms. **It appears these disturbances cannot be abated to the overall detriment of the Coos Bay estuary.**

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[126] When Dr. Ravens refers to ‗Exhibit 4,' he is referring to ―Technical Report Volume 2 - Jordan Cove Energy Project and Pacific Gas Connector Pipeline, Coastal Engineering Modeling and Analysis, dated March 9, 2011, prepared by Coast & Harbor Engineering, Inc

[127] <u>November 14, 2011</u>: Mark Chernaik, Ph.D., Surrebuttal Report submitted into the record by e-mail on Jan 12. 2015. Exhibit 3: *―Limitations of the Haynes Inlet sediment transport study,"* by Tom Ravens, Ph.D., Professor, Department of Civil Engineering, University of Alaska, Anchorage; November 13, 2011; Page 2,4

[128] 8.0 Summary ; *―Jordan Cove Energy Project - ―Jordan Cove LNG Terminal Shoreline Erosion Study - Recommendation #15"* M&N Project No. 6753; Document No. 6753RP0002 Rev: 0; (Page 48) Docket No. CP07-444-000 http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20081205-5122

HISTORICAL SITES AND CULTURAL RESOURCE IMPACTS

The export facility is proposed on the traditional territory of the Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians. The Tribes have known cultural resources at this location and are attempting to monitor and work to the best of their ability to protect those. Construction of the two berth slip, off loading facilities, tanks, and power plant may destroy cultural resources. The linear north-south hill along the east boundary of the proposed facility most likely would have been used by Native Americans for burial sites. **Federal law dictates no impact to such by any federal permitting process, regardless of land ownership.** The adjacent shoreline is littered with historic remnants; it is difficult to understand why no value is attributed.

Photo to right is of a glass artifact found in the tidal areas of the proposed LNG marine terminal in May of 2018. It is unknown what may be just below the surface from past Tribal people that lived in these areas.

Conde B. McCullough Memorial Bridge

The Conde B. McCullough Memorial Bridge, is a cantilever bridge that spans Coos Bay on U.S. Route 101 near North Bend, Oregon. When completed in 1936 it was named the Coos Bay Bridge. In 1947 it was renamed in honor of Conde B. McCullough who died that year. This and 10 other major bridges on the Oregon Coast Highway were designed under his supervision.

The Conde B. McCullough Memorial Bridge replaced ferries that had formerly crossed the bay. The bridge is outstanding for its attention to form and detail, and **has been placed on the National Register of Historic Places in recognition of its design and cultural and economic importance**. Placing a potential pipeline bomb directly under the bridge would not be in line with the protection the bridge has as a registered historical site. The main towers of the Conde B. McCullough Memorial Bridge rise 280 feet (85 m) above the water surface, with curved sway bracing in a Gothic arch style. **The open-spandrel concrete approach arches vary in span from 265 feet (81 m) to 151 feet (46 m)**. The ends of the bridge are marked by pedestrian plazas meant to provide a viewing point for the bridge and to provide access to the shoreline. These plazas are detailed with Art Moderne motifs and are provided with built-in benches. The stairs are descend in sweeping curves to the park below.

Due to the high operating pressure, the proposed Pacific Connector Gas Pipeline hazardous zone would extend out 800 to over 1,000 feet from the center of the proposed pipeline. **It would NOT be acceptable to locate a hazardous pipeline such as this under a historically registered bridge.**

Pacific Connector Gas Pipelines Resource Report #1 that was filed with the FERC on September 21, 2017 states on page 10 the pipeline maximum allowable operating pressure will be increased from 1480 to 1600 psig.

Pacific Connector's 2017 FERC application under 18. GENERAL OPERATING PROVISIONS states:

> *18.3 Pressure Obligations at Receipt Points*
> *Shipper is responsible for ensuring that Scheduled Quantities are delivered to Transporter at the specified Receipt Points at pressures sufficient to allow the Gas to enter the facilities of Transporter,* ***<u>but not at pressures below eight hundred-fifty (850) psig or in excess of the maximum allowable operating pressure</u>*** *of Transporter's facilities at such Receipt Points, unless a lower pressure is otherwise mutually agreed to between Shipper and Transporter with such pressure specified for such Receipt Point in Exhibit A of such Shipper's firm Service Agreement.*

Pacific Connector Gas Pipeline's Gas Quality and Interchangeability Chart filed in with their FERC application also shows the minimum pressure to be 850 psig. By using the graph provided in ***Exhibit 64***, a 36-inch pipeline operating at 850 psig would have a hazard radius of approximately that same distance.

On December 3, 2011, a Williams-Transco pipeline ruptured in Alabama.[129] The explosion was heard more than 30 miles away and flames shot up nearly 100 feet in the air for 90 minutes after the pipeline was shut off. The pipe was a 36″ diameter gathering line. A 43 foot long section blew up and became a missile that landed 190 feet away from the blast site and traveled over the tops of 70 to 80 foot high trees to get to its final resting place. The accident left a crater more than 50 feet wide, destroyed 65 acres of trees and left 5 acres of soil that is like fired clay pottery. The cause was never announced. There was no construction going on so it was assumed to be caused by corrosion.[130] (See photo's below) Since 2006, Williams-Transco has had 35 PHMSA reportable accidents.

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[129] http://www.texassharon.com/2012/01/02/pictures-acres-of-devistation-from-williams-gas-pipeline-explosion-in-alabama/

[130] http://spectrabusters.org/2014/01/26/a-36-inch-pipeline-blews-up-in-alabama/

 

Due to the high operating pressure, the proposed Pacific Connector Gas Pipeline hazard zone would be far greater than the accident noted above.

EARTHQUAKE / TSUNAMI HAZARD ISSUES

The Jordan Cove facility resides in the Cascadia subduction zone and Jordan Cove's LNG Hazardous Burn Zones have been underestimated according to top LNG hazard experts.[131] There is no Evacuation Plan and/or Emergency Response Plan for the facility, particularly if the Transpacific Parkway highway connecting the facility to Highway 101 fails. The LNG storage tanks, power plant and gas processing facility would be constructed on what is currently dredging spoils so its foundation would be on weak foundation soils that are likely to liquefy in the event of a Cascadia subduction earthquake event occurring off our coast here. A 13 year study completed by researchers in 2012 at Oregon State University, and published by the U.S. Geological Survey, concluded that **there is a 40 percent chance of a major earthquake in the Coos Bay, Ore., region during the next 50 years**. <u>And that earthquake could approach the intensity of the Tohoku quake that devastated Japan in March of 2011</u>.[132] (***See Exhibit 26***)

There are no plans on how Jordan Cove or their Fire and Safety Center would protect the Cities across the Bay that would be negatively impacted due to their increase in population and Jordan Cove's

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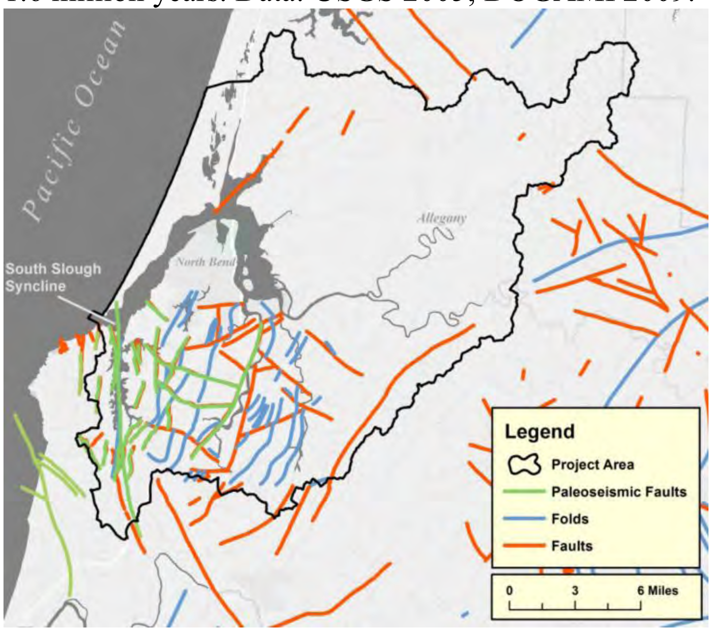
[131] 1-14-2015 - Jerry Havens Ph.D and James Venart Ph.D under CP13-483
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150114-5038
2-6-2015 - Supplementary Comment with Questions by Jerry Havens and James Venart under CP13-483.
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150206-5040

> Professor Havens and Professor Venart found significant discrepancies and problems with Jordan Cove's hazard analysis and determined the hazards had been significantly underestimated. Safety measures incorporated in the proposed Jordan Cove LNG terminal actually increase the chance of a catastrophic failure and present a far more serious public safety hazard than regulators have analyzed and deemed acceptable. In their Feb 6, 2015, filing with the FERC, Professor Havens and Professor Venart asked specific questions to the FERC that have yet to be answered.

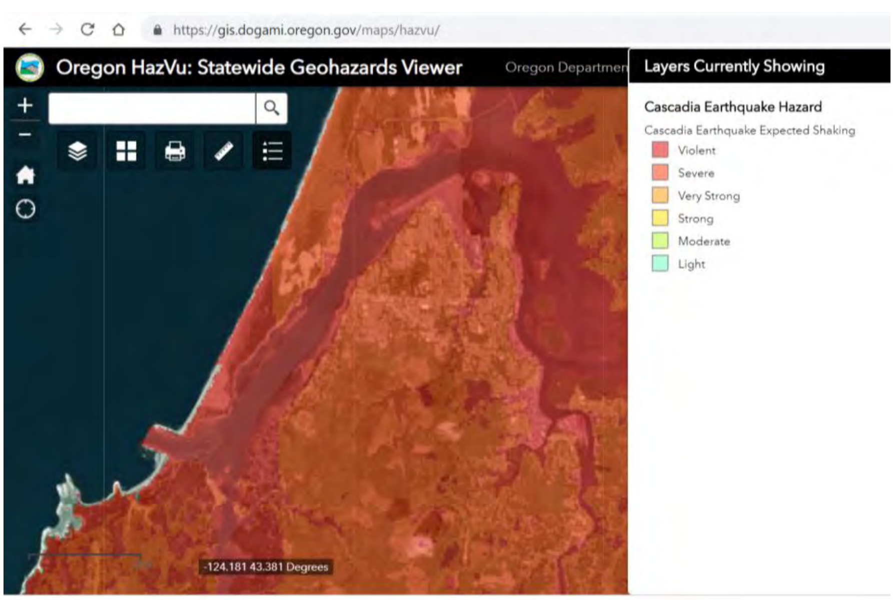
[132] 13-Year Cascadia Study Complete – And Earthquake Risk Looms Large
http://oregonstate.edu/ua/ncs/archives/2012/jul/13-year-cascadia-study-complete-%E2%80%93-and-earthquake-risk-looms-large
Study Link: *Turbidite Event History—Methods and Implications for Holocene Paleoseismicity of the Cascadia Subduction Zone* - By Chris Goldfinger, C. Hans Nelson, Ann E. Morey, Joel E. Johnson, Jason R. Patton, Eugene Karabanov, Julia Gutiérrez-Pastor, Andrew T. Eriksson, Eulàlia Gràcia, Gita Dunhill, Randolph J. Enkin, Audrey Dallimore, and Tracy Vallier - http://pubs.usgs.gov/pp/pp1661f/

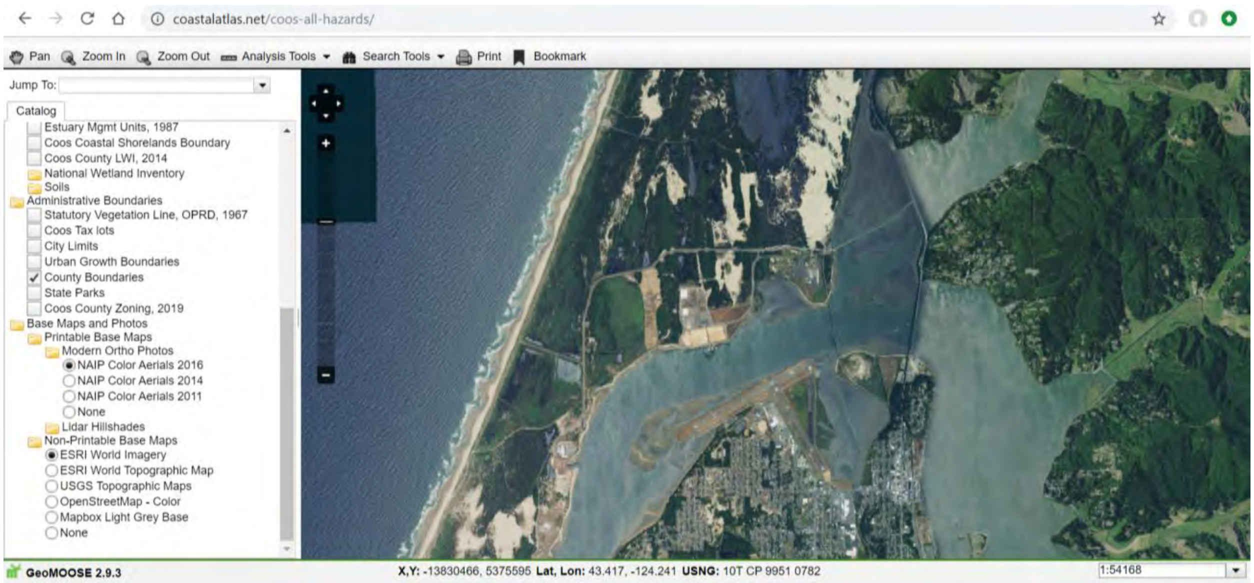
proposed LNG hazards. There are no plans for Jordan Cove to hire extra emergency response personnel and in fact the Cities of North Bend and Coos Bay have both indemnified Jordan Cove from any hazard liability.

The Figure below shows faults and folds occurring within project boundaries. Paleoseismic faults are highlighted, designating faults that were the source of significant earthquake (6.0 or greater) in the past 1.6 million years. Data: USGS 2005; DOGAMI 2009. (***See Exhibit 25***)

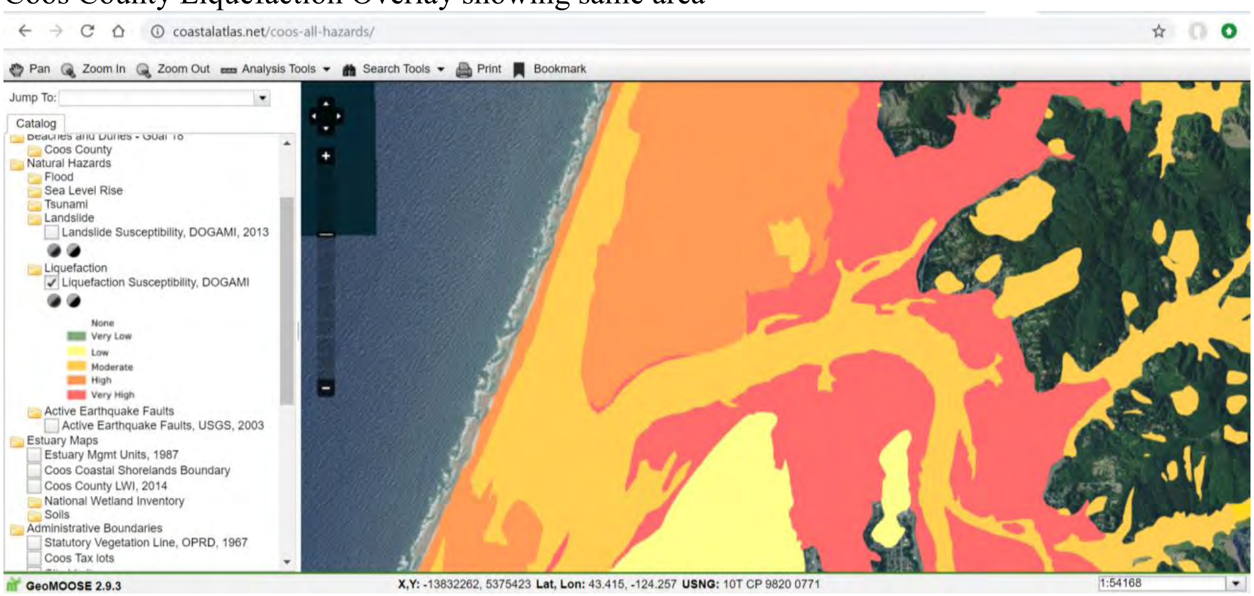


Earthquake Hazard Diagrams below were taken from the Department of Geology and Mineral Industries (DOGAMI) on-line Geohazards Viewer http://www.oregongeology.org/hazvu/

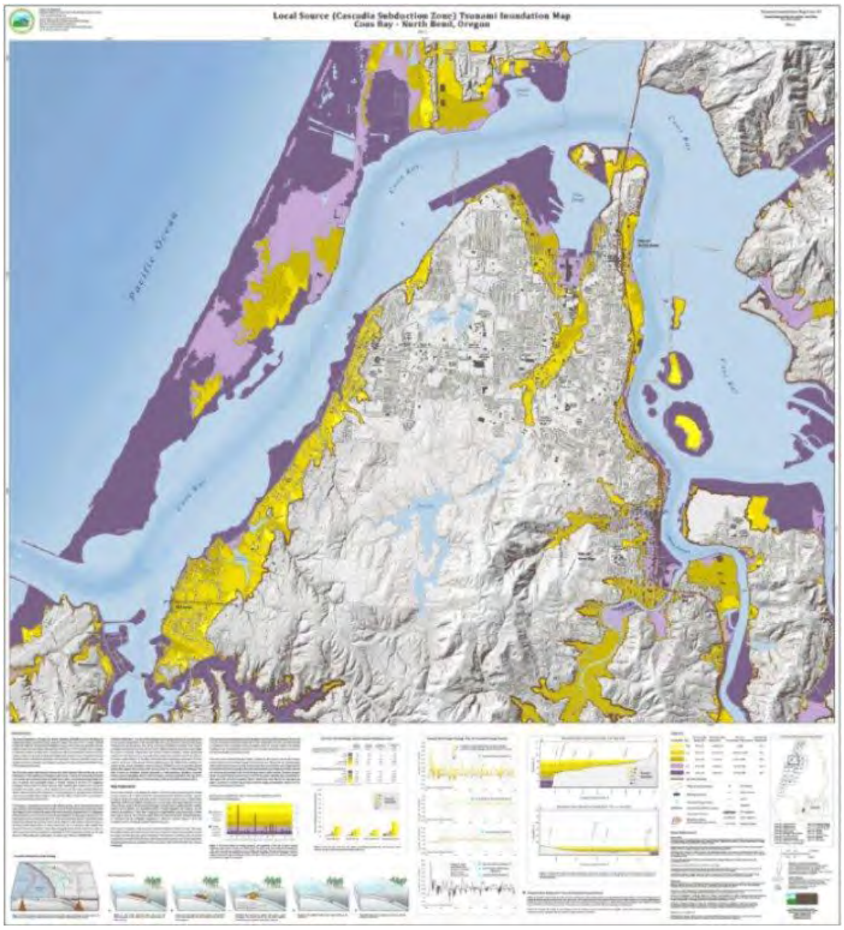




Coos County Liquefaction Overlay showing same area



Statewide Planning Goal 7 does not allow the building of hazardous facilities in natural hazard zones. It also requires that applicants consult with the Oregon Department of Geology and Mineral Industries (DOGAMI). The DOGAMI determined in a letter dated November 6, 2017 that Jordan Cove's Resource Reports were incomplete and deficient in scientific and engineering analyses related to geologic hazards and were not adequate to insure public safety. (***See Exhibit 65***) Below find DOGAMI tsunami inundation map of the Coos Bay Estuary:

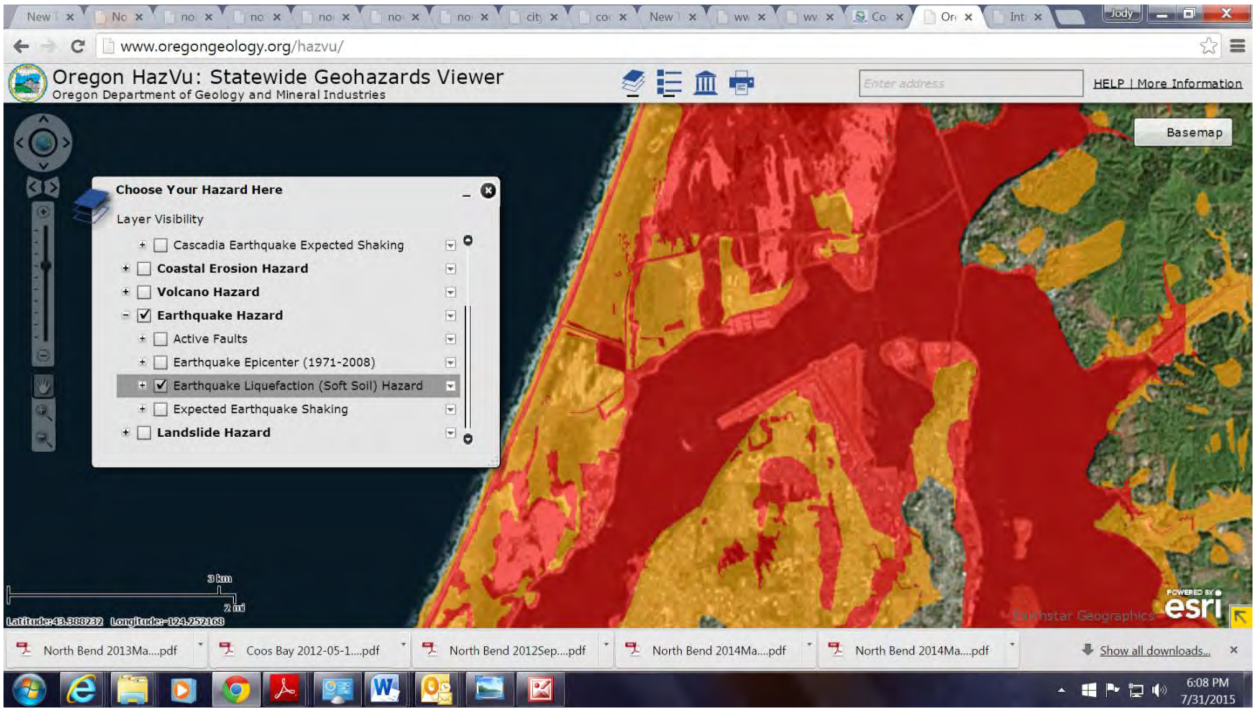


The Jordan Cove / Pacific Connector Project would increase water volume in the Coos Bay which would increase tsunami and flooding hazards. Jordan Cove's tsunami study shows the increased tsunami hazards due to their proposed removal fill on the North Spit. (***See Exhibit 67***) It only makes sense that this would **also** be the case due to their dredge disposal dumping on the APCO sites in North Bend and their Kentuck Mitigation site plans. (***See Exhibits 6 and 66***)

The tsunami that inundated Japan in 2011 proved that tsunami wave heights can and likely will go up much higher than what Jordan Cove is preparing for. USA today reported that:

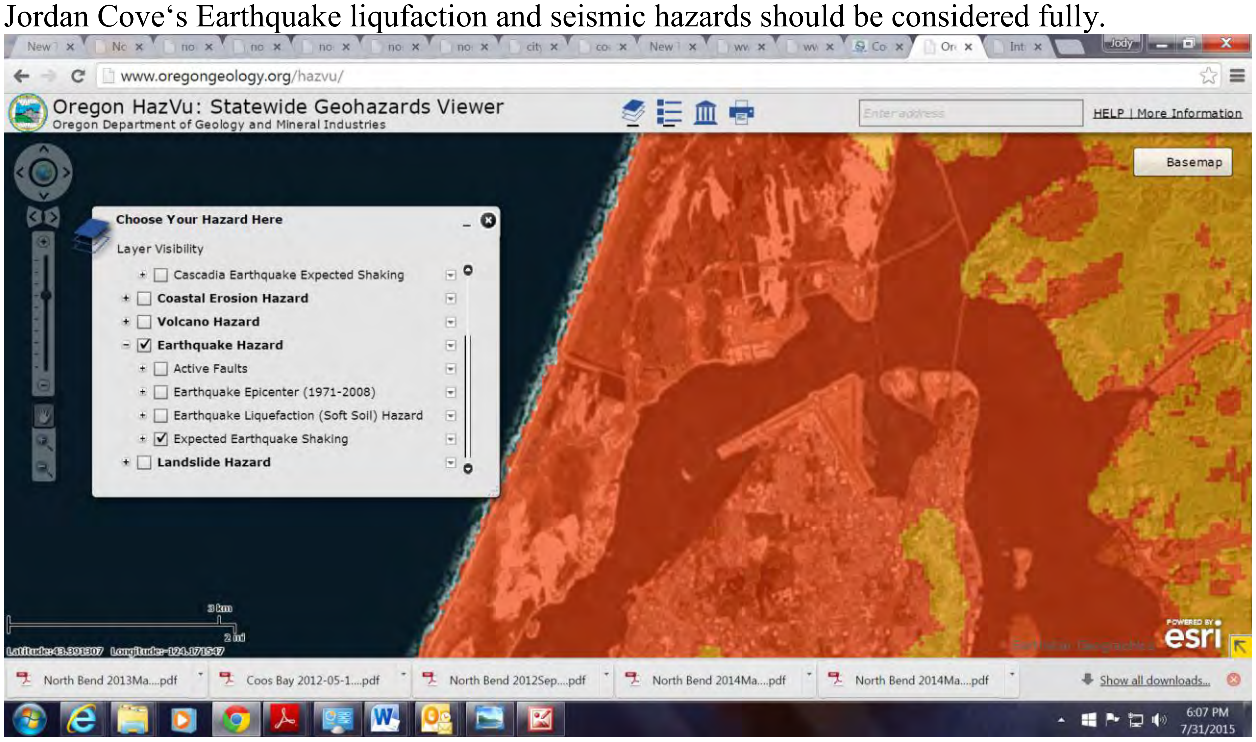
> ***Tsunami waves topped 60 feet or more*** *as they broke onshore following Japan's earthquake, according to some of the first surveys measuring the impact along the afflicted nation's entire coast.* ***Some waves grew to more than 100 feet high, breaking historic records****, as they squeezed between fingers of land surrounding port towns.*[133] (Emphasis added)

[133] *Japan's tsunami waves top historic heights*; By Dan Vergano, USA TODAY; 4/25/2011 http://usatoday30.usatoday.com/news/world/2011-04-24-Japan-record-tsunami-waves.htm



http://www.oregongeology.org/hazvu/

Jordan Cove's Earthquake liqufaction and seismic hazards should be considered fully.



http://www.oregongeology.org/hazvu/

When one also considers that the entire LNG facility would be built on fill and dredging spoil sand that water can easily and quickly penetrate, this confirms the instability of the soils which would liquefy and subside during the projected Cascadia subduction event. The Oregon Resilience Plan that was prepared for the 77th Legislative Assembly on February 2013 reported on earthquake and tsunami impacts from a Cascadia event and **showed subsidence levels of 5 to 9 feet in the Coos Bay area**.

This adds to the extreme hazard and need for there to be a far better evacuation plans in order for lives to be saved. Workers and citizens should not be placed at extreme risk due to by improper planning. An LNG export terminal poses far too much risk and hazard to be built here. (***See Exhibit 27***)

The New Yorker magazine reported on July 20, 2015 the following concerning the projected Cascadia subduction event that is scheduled to occur at any time off our coast here in an article by Kathryn Schultz entitled, ***―The Really Big One - An earthquake will destroy a sizable portion of the coastal Northwest. The question is when***." [134]

> *…**By the time the shaking has ceased and the tsunami has receded, the region will be unrecognizable**. Kenneth Murphy, who directs FEMA's Region X, the division responsible for Oregon, Washington, Idaho, and Alaska, says, ―**Our operating assumption is that everything west of Interstate 5 will be toast**."…*
>
> *…**FEMA projects that nearly thirteen thousand people will die in the Cascadia earthquake and tsunami**. Another twenty-seven thousand will be injured, and the agency expects that it will need to provide shelter for a million displaced people, and food and water for another two and a half million. ―This is one time that I'm hoping all the science is wrong, and it won't happen for another thousand years," Murphy says.*
>
> *In fact, the science is robust, and one of the chief scientists behind it is Chris Goldfinger. Thanks to work done by him and his colleagues, we now know that the odds of the big Cascadia earthquake happening in the next fifty years are roughly one in three. The odds of the very big one are roughly one in ten. **Even those numbers do not fully reflect the danger—or, more to the point, how unprepared the Pacific Northwest is to face it**….*
>
> *…Those who cannot get out of the inundation zone under their own power will quickly be overtaken by a greater one. **A grown man is knocked over by ankle-deep water moving at 6.7 miles an hour. The tsunami will be moving more than twice that fast when it arrives. Its height will vary with the contours of the coast, from twenty feet to more than a hundred feet**. It will not look like a Hokusai-style wave, rising up from the surface of the sea and breaking from above. It will look like the whole ocean, elevated, overtaking land. Nor will it be made only of water—not once it reaches the shore. It will be a five-story deluge of pickup trucks and doorframes and cinder blocks and fishing boats and utility poles and everything else that once constituted the coastal towns of the Pacific Northwest….*
>
> *…OSSPAC estimates that in the I-5 corridor it will take between one and three months after the earthquake to restore electricity, a month to a year to restore drinking water and sewer service, six months to a year to restore major highways, and eighteen months to restore health-care facilities. **On the coast, those numbers go up. Whoever chooses or has no choice but to stay there will spend three to six months without electricity, one to three years without drinking water and sewage systems, and three or more years without hospitals. Those estimates do not apply to the tsunami-inundation zone, which will remain all but uninhabitable for years**….*

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[134] *The Really Big One - An earthquake will destroy a sizable portion of the coastal Northwest. The question is when.*
By Kathryn Schulz; The New Yorker; July 20, 2015
http://www.newyorker.com/magazine/2015/07/20/the-really-big-one

An Oregonian article that was published on June 26, 2014, entitled, ~~"~~**Jordan Cove LNG terminal at Coos Bay designed for Cascadia quake, tsunami though hazards remain**," stated among many other things the following:

> *…"It should be an assumption that this will happen during the lifetime of the facility," said Chris Goldfinger, a seismologist at Oregon State University and leading authority on subduction zone earthquakes. "You can engineer anything to survive anything if you put enough money into it, but I've seen a lot of very well-engineered stuff destroyed as if it were Legos."*
>
> ***"From my perspective, and the probabilities, I would certainly have reservations about building one of these terminals down there,"*** *he said…*
>
> *…**"I would say every one of us would be reluctant to suggest a liquefied natural gas terminal on the coast here,"** said Anne Trehu, an OSU geologist who studies the Cascadia Subduction Zone….*
>
> *…Run-up and subsidence estimates were considerably less for the smaller, more likely, earthquake scenarios that Zhang modeled. In either case, the study concluded that the height of the proposed design "exceeds the design level tsunami event."*
>
> *Yet Zhang also says "**all the results need to be taken with a grain of salt**." Before the Japanese quake in 2011, he said**, geophysicists had concluded that 15-meter-high waves <u>were not possible at Fukushima</u>**.*
>
> ***Yet that's exactly what happened, resulting in cascading series of failures that ultimately resulted in the meltdown of three nuclear reactors***.[135] (Emphasis added)

Statewide Planning Goal 7 does not allow the building of hazardous facilities in natural hazard zones. It also requires that applicants consult with the Oregon Department of Geology and Mineral Industries (DOGAMI). The DOGAMI determined in a letter dated November 6, 2017 that Jordan Cove's Resource Reports were incomplete and deficient in scientific and engineering analyses related to geologic hazards and were not adequate to insure public safety. (***See Exhibit 65)***

EARTHQUAKE AND WEAK FOUNDATION SOILS

Jordan Cove's GRI Report is flawed due to not including all the earthquake faults lines that are in our area, particularly those near the proposed Jordan Cove facility.

Page 130 of Jordan Cove's 1-12-2016 submittal into the Coos County HBCU-15-05 land use proceeding is from their GRI report and shows the following Earthquake Faults that were included in their study with respect to the LNG terminal only:

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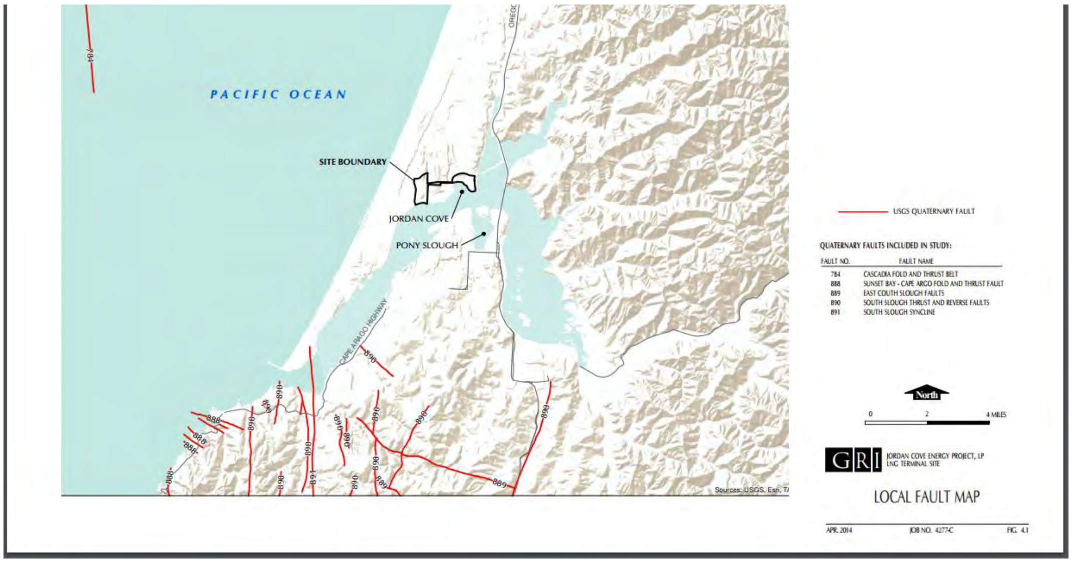
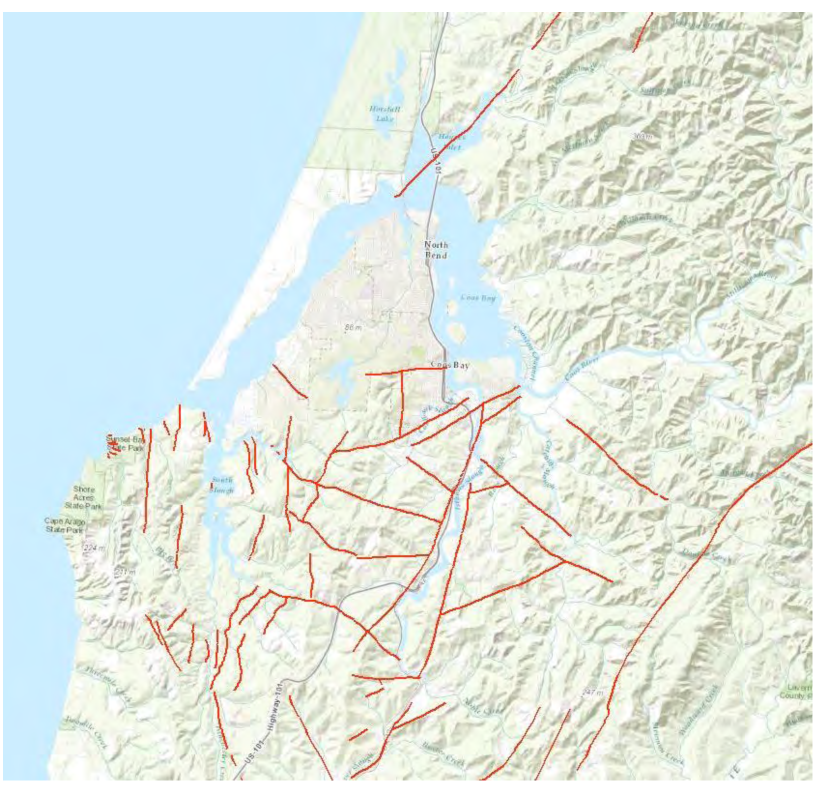
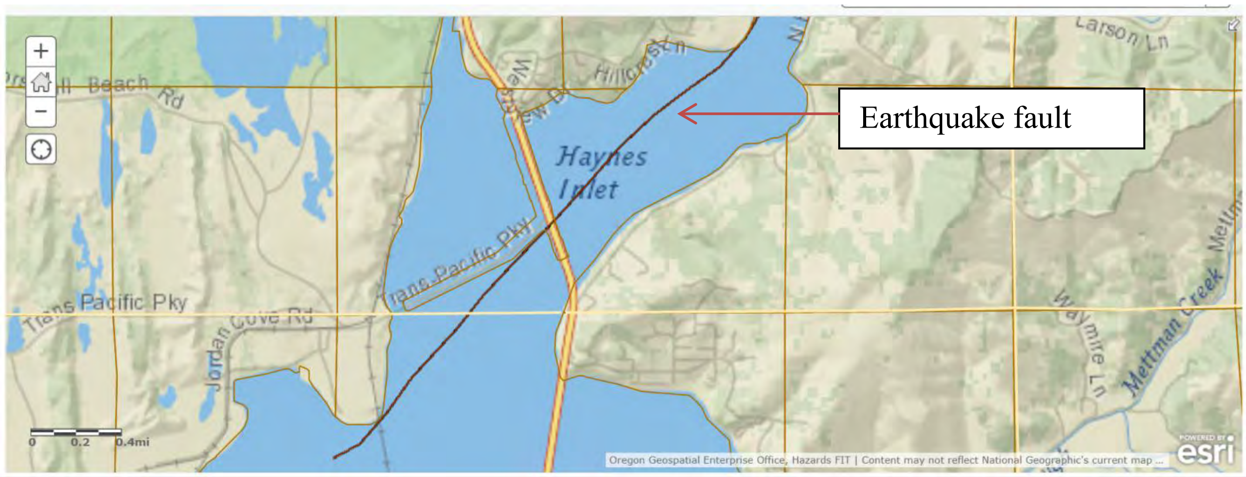
[135] *Jordan Cove LNG terminal at Coos Bay designed for Cascadia quake, tsunami though hazards remain*
By Ted Sickinger - The Oregonian - June 26, 2014
http://www.oregonlive.com/business/index.ssf/2014/06/coos_bay_lng_terminal_designed.html#incart_river



The Jordan Cove GRI study did not include the impact from the earthquake fault line that is in the Haynes Inlet area along with several others that are near where the proposed LNG export facility would be built. The diagram below comes from the Department of Geology and Mineral Industries (DOGAMI) and shows additional earthquake fault lines in the Coos Bay area in 2009:

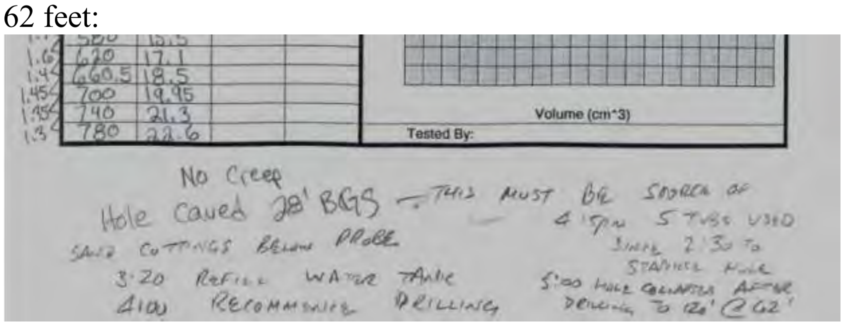


As you can see, some key earthquake fault lines were not included in Jordan Cove's GRI study which would affect the study's analysis and determinations. In addition, Jordan Cove's Pacific Connector feeder line would directly cross an earthquake fault line as it goes under the Bay. This would be in violation of Oregon Statewide Planning Goal #7,[136] and also applies to the Jordan Cove facility in general also.



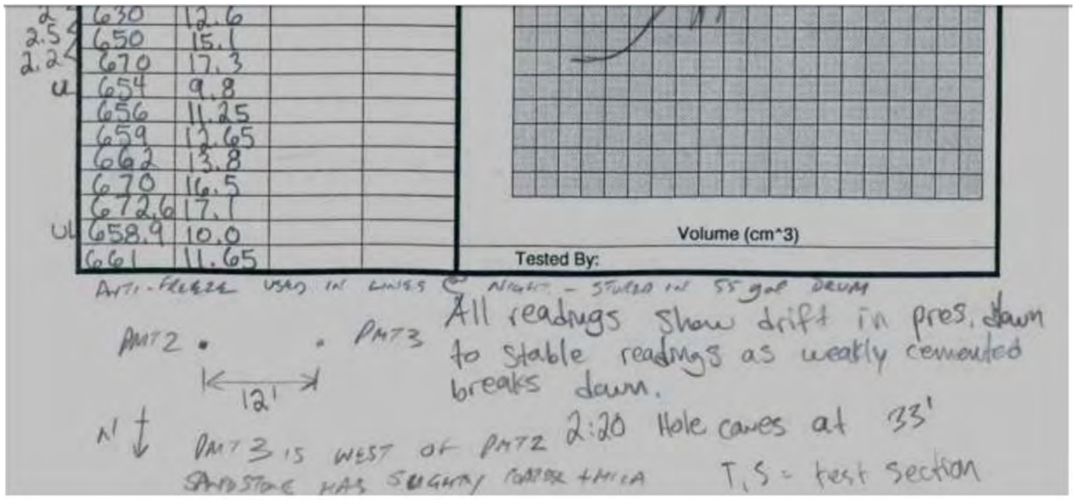
Jordan Cove's GRI report noted above also shows that there is weakness in the soils in the area of the LNG storage tanks.

On page 682 of Jordan Cove's 1-12-2016 submittal under Coos County File No. HBCU-15-05[137] it states that the test hole caved at 28 feet and also at 5:00 the hole collapsed after drilling to 120 feet at 62 feet:



[136] http://www.oregon.gov/LCD/docs/goals/goal7.pdf
[137] http://www.co.coos.or.us/Departments/Planning/2015Applications.aspx

Page 683 of Jordan Cove's 1-12-2016 submittal states that all readings showed a drift and that at 2:20 the hole caved at 33 feet.



Page 739 of Jordan Cove's 1-12-2016 submittal under Coos County File No. HBCU-15-05 states the following:

6. Conclusion

We are here in a site with quite stiff sandy soil. According to the geotechnical baseline report, we can assume shallow foundations are feasible below these 160,000 m3 LNG tanks.

Due to seismic considerations, some ground improvements should however be required on site so as to improve the wet fill layer and maybe deeper sand pockets. A new site investigation made with CPT tests and SPT is about to begin on site so to get an accurate idea concerning the soil improvement needed or not.

Realized calculations with the FEM model and the double raft shows us:
- Absolute settlement below the tank will be inferior to 30 cm during the operating period of the tank (among 10 cm during the construction),
- Deflection will always be inferior to 1/300.

An independent review on if these soils to determine if they are adequate to build on is in order to protect the public health, safety and welfare of Coos County citizens.

MITIGATION ISSUES AND INSUFFICIENCIES

Aquatic habitats are marine, intertidal, riverine, and wetland. Direct losses from construction of the project to intertidal habitat are supposed to be mitigated by flooding the Kentuck Golf and Country Club grounds. It makes no sense to us to destroy existing land and freshwater habitat to "ameliorate" the negative impacts of trenching a portion of the estuary for the proposed slip and pipeline. Improving existing tidal flat areas in the bay would be far superior mitigation effort toward recovering biological productivity. The South Slough recovery amply demonstrates the social and natural rewards of wise stewardship.

Riverine and wetland aquatic habitats are nationally recognized as critical habitats; thereby, federal laws have been extensively developed and refined since the 1970's to protect them. Strict environmental review to deal with adverse effects to riverine or wetland habitats require setting stringent terms and conditions. For example, avoidance of impact from pipeline development could certainly be obtained by utilizing existing Department of Transportation (DOT) and utility corridors. Also, the existing rail spur on the North Spit is capable, via tanker cars, to move LNG or natural gas to any destination.

Terrestrial habitats impacted are lowland and upland shrub and forest, bottomland pastures and riparian. The seral stage of the habitat basically identifies its former or present use by man or natural process of restoring its viability. The linear north-south hill where the facility would be developed did show a healthy, vigorous upland habitat type. Also, along the proposed pipeline, a great deal of pristine habitat exists (not trammeled by man). The Right of Way (ROW) is purposely planned narrower in width (especially on federal lands) to avoid negative impacts. This measure increases the safety risk and potential for increased maintenance and repair. **Clearing trees for the ROW will change fierce wind patterns.** Wetland and riparian associated timber will exasperate problems of pipeline corridor maintenance. These trees have shallow root zones and will blow over. We suggest that narrowing the proposed ROW will not reduce the environmental or safety consequences of the pipeline rather, increase the project costs. There would be no likely manner to remedy this change.

The surrounding mitigation sites that were previously developed by Weyerhaeuser on the North Spit do not appear to have been successful and have had very little upkeep and oversight. There is very little wildlife present there. **Any mitigation effort must prove to be successful beyond a 5 year time span.** The Weyerhaeuser mitigation site failure proves that mitigation efforts are not always successful. We cannot afford any more failures. Monitoring efforts need to be established that go beyond 5 years and a bond should be set up ahead of time to ensure that any mitigation that is proposed ends up being successful and not just a useless effort by the applicant in order to obtain their permits.

If wetlands are destroyed or degraded even by temporary workspace, depending on mitigation, they may never recover to their former character or it may take 5 years or more to do so. The loss of primary productivity and nutrient distribution is permanent and not temporary. **<u>If a potential risk to the survival or recovery of a threatened or endangered species exists, the applicant must redesign or relocate the facility to avoid that risk or propose appropriate mitigation measures</u>**.

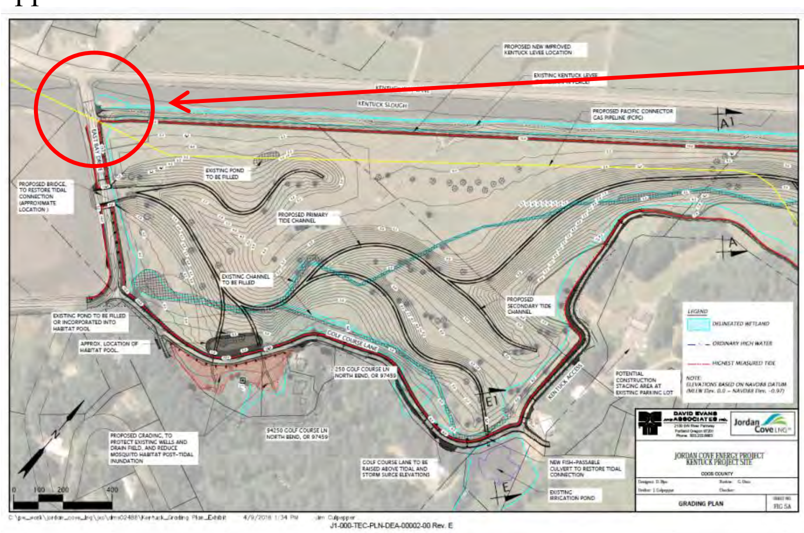
Mitigation Insufficient / Lacking. Dredging / Temporary Dredge Pipeline would impact Eelgrass and other habitat areas.

Jordan Cove has yet to prove a need for their dredging project that outweighs the negative impacts to fishing, recreation and navigation. They have provided no plans to mitigate habitat areas and marine life that would be destroyed by their proposed dredging plans. Jordan Cove's proposed eelgrass mitigation site also lacks sufficient proof that it would be successful.

Jordan Cove's proposed dredging, eelgrass mitigation site, and temporary pipeline would directly impact known eelgrass areas in the Coos Bay as documented by the letter from Shon Schooler, Ph, D and as shown in the following diagrams. (***See Exhibit 10***) No evidence has been provided as to how these impacted areas would be successfully restored after being impacted. In addition, Jordan Cove's 2007 Coos Bay Estuary Mitigation permit has long since expired. (CBDC **17.130.140**) It is unclear how they plan to successfully mitigate eelgrass areas that would be destroyed by their dredging plans.

In addition, due to improper hydrology studies being done by Jordan Cove, the proposed mitigation site up the Kentuck inlet is highly likely to cause increased flooding in the inlet. (***See Exhibit 66***)

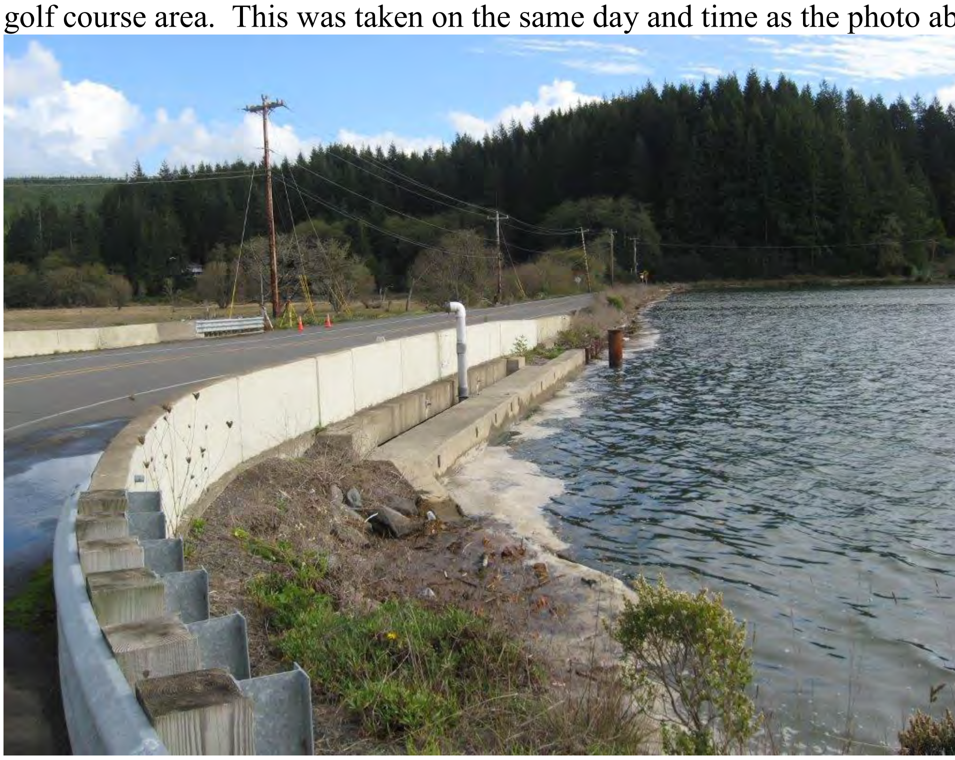
The following diagram is shown in the current 401 application of the proposed mitigation site. Jordan Cove plans on running their Pacific Connector Gas Pipeline under the current Kentuck tidegate that links the Coos Estuary to several upland streams and spawning areas. This is a fish passage area and could spell total disaster and instability to this particular tide gate. Alternative pipeline routes could have been considered that did not impact the estuary at all. This is why an EIS should have been completed first before Coos County, the Army Corp, DEQ and DSL processed Jordan Cove's applications



The current Pacific Connector Gas Pipeline Route goes directly under the East support for the current operating Kentuck Inlet tide gate.

The photo below was taken on Oct 6, 2015, and shows the existing dike that runs along the Kentuck slough that separates it from the former golf course that is currently being proposed as a wetland mitigation site for Jordan Cove. This photo below is on the North side of the East Bay Drive where it crosses the Kentuck Slough and the former golf course area. As the photo shows, the existing dike is not high enough to retain the water levels and volumes that Jordan Cove is proposing for their mitigation project.

Photo below: South side of the East Bay Drive where it crosses the Kentuck Slough and the former golf course area. This was taken on the same day and time as the photo above.



At the hearing on December 18, 2015, Barbara Gimlin, former Jordan Cove Environmental lead, testified as to the flooding issues **that are already occurring on Kentuck Slough** to the North of the East Bay Drive due to Main Rock's placement of fill next to the Slough without proper hydrology studies and approvals. Jordan Cove's Feb 2, 2014 Supplement to Technical Memorandum – Tsunami Hydrodynamic Modeling report (***See Exhibit 67***) clearly shows the upland stream impacts from placing fill on the North Spit property:

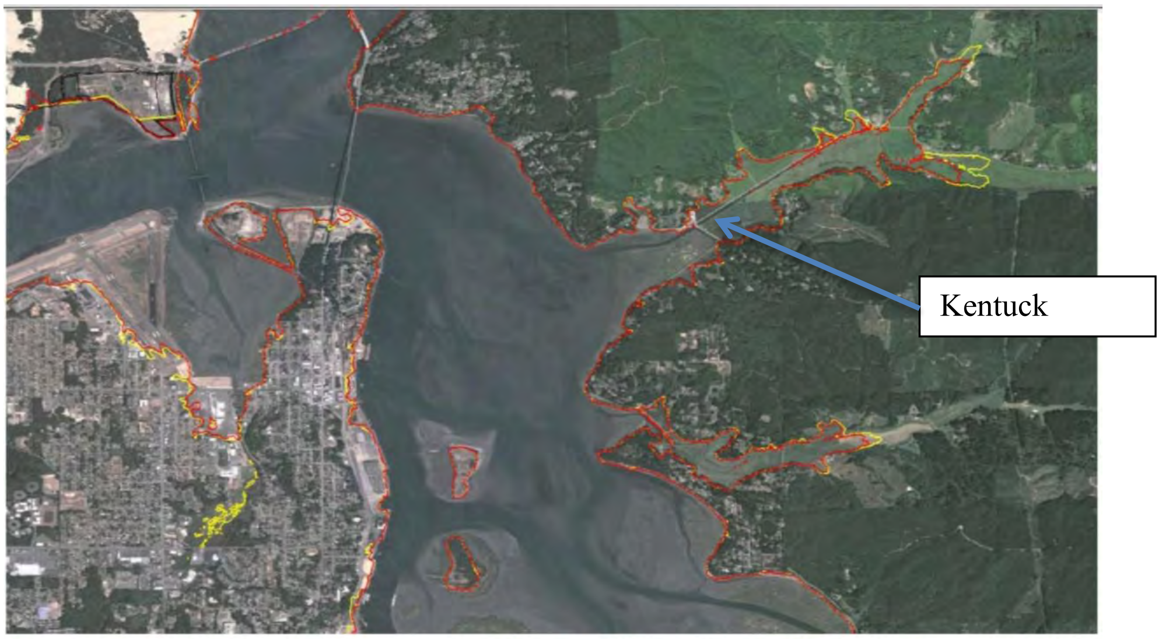
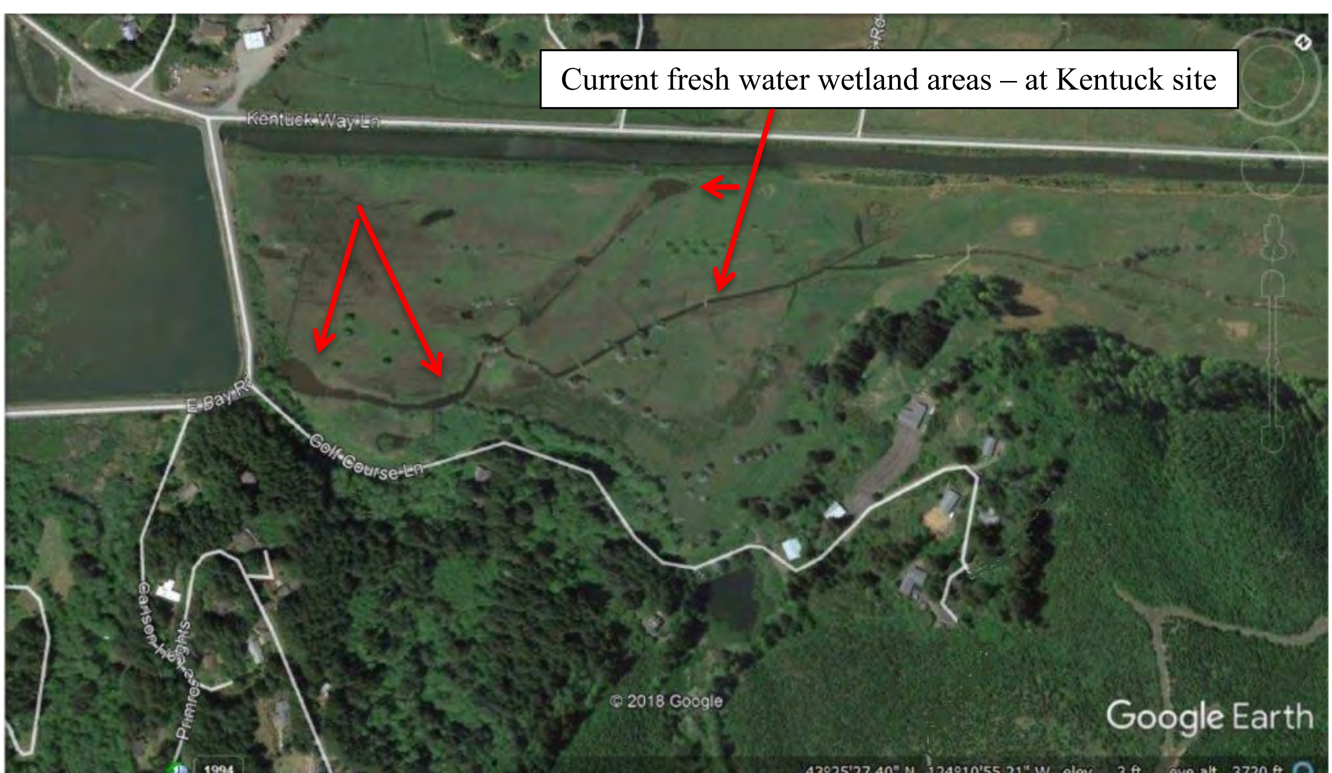


Figure 3. Extent of tsunami wave inundation for L1 Scenario further east of project site for modified landscape obtained from Zhang (2012) study, shown in yellow and CHE (2013b) study, shown in red

Fresh water wetlands and habitat already existing at the Kentuck Golf course mitigation site would be lost along with existing habitats currently located there. These impacts are not being mitigated properly. The proposed flooding of the golf course that JC has planned would also affect Golf Course lane and properties that depend on this road for access to East Bay Drive.

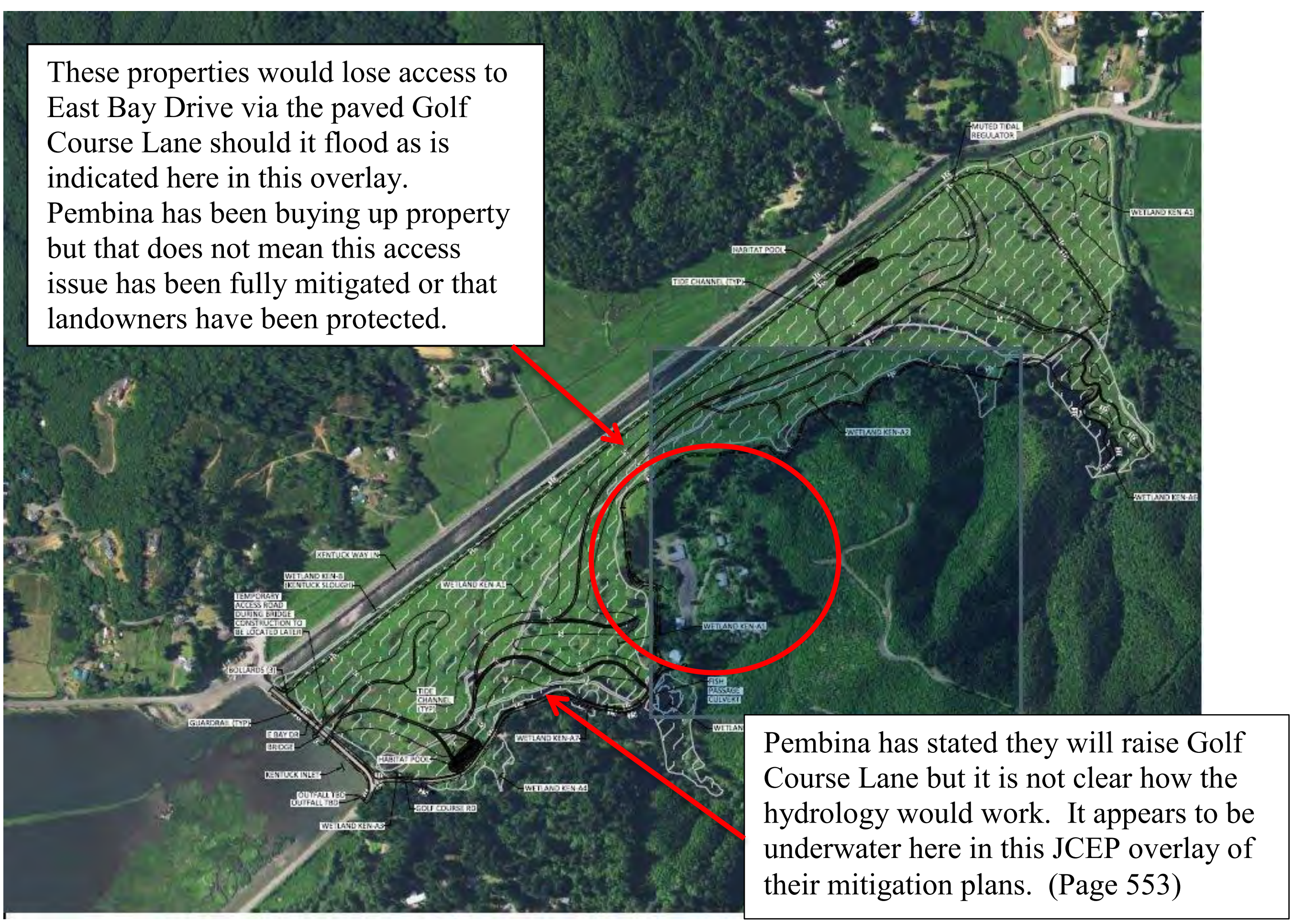


Jordan Cove's proposed mitigation is insufficient mitigation and in some cases is not even located in the same watershed. **Mitigation should remain in the same watershed that is being impacted**. It is irresponsible to allow Jordan Cove to destroy the Coos Bay Estuary lower bay and then do a mitigation project in the upper bay where different habitats exist or at Gardiner some 22 miles North or in Bandon some 30 miles to the South.

Below from electronic page 553 of Jordan Cove's DSL application shows areas that would be flooded with tidal salt marsh AFTER Jordan Cove's mitigation plan. Jordan Cove has been buying up property in this area but not everyone on Golf Course Lane has sold their property to them. This is some of the most desirable property in our area and it is really a shame that they are doing this. **The Kentuck Golf Course was previously used heavily by the locals here as it had reasonable fees and supported local fundraising golf events.** Locals could afford to golf there but now it will be gone and a significant amount of landowners who live around the former golf course may end up not having access to those properties should Jordan Cove proceed.

Jordan Cove is currently in the process of obtaining a 15-year tax abatement. Money will instead flow into a private non-profit. Jordan Cove is currently buying up large sections of property In Coos County that I have to assume will be taken off the tax rolls. They currently have not been paying the same tax rate as the rest of the people who currently live in Coos County pay.

This is NOT IN THE PUBLIC INTEREST.



The Eelgrass Mitigation site that would be located in Coos Bay, adjacent to the Southwest Oregon Regional Airport, is likely to conflict with the airport's planned expansion project noted in the diagram below on the left from Southwest Oregon Regional Airport Master Plan:[138]

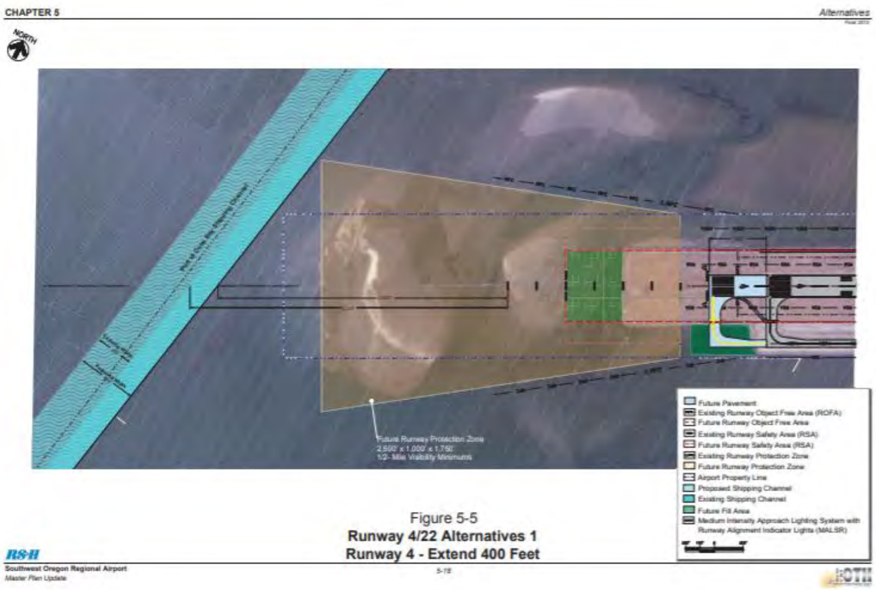


Figure 5-5
Runway 4/22 Alternatives 1
Runway 4 - Extend 400 Feet

Above from DSL Application page 1173

The turbidity caused from dredging in an area that is already right next to an eel grass mitigation site is likely to be detrimental to the eel grass beds that are located there. (***See Exhibit 61***)

Jordan Cove's temporary dredge transfer line appears to impact the entire lower bay of the Coos Estuary. The impact of that line on eel grass beds is uncertain. It is also unclear if the habitat and marine life that would be present in or near the proposed dredge removal sites are being properly mitigated for. Marine life that may be inadvertently sucked into the transfer pipe would end up with a death sentence and no hope of recovery. These critical impacts need to be FULLY considered and at the very least mitigated.

SAFETY ISSUES

- Industry SIGTTO Guidelines,[139] Sandia National Laboratory Guidelines[140] and GAO Report Guidelines[141] are not being followed. **The Application does not address the project's notable departures from industry standards or our scoping comments on those departures.**

[138] http://cooscountyairportdistrict.com/files/uploads/2015/06/OTH_Chapter_5_Alternatives.pdf
[139] –*Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14*" - Published by Society of International Gas Tanker and Terminal Operators Ltd / 1997
[140] SANDIA REPORT –*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*"; Mike Hightower, Louis Gritzo, Anay Luketa-Hanlin, John Covan, Sheldon Tieszen, Gerry Wellman, Mike Irwin, Mike Kaneshige, Brian Melof, Charles Morrow, Don Ragland; SAND2004-6258; Unlimited Release; Printed December 2004; http://www.fossil.energy.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf
[141] United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; –*Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf

- Airport airspace and Presumed Hazard issues are not being addressed properly. These issues are also not addressed in the Coast Guard's LOR or Jordan Cove's Memorandum of Understanding (MOU).

- Coast Guard WSA ignored the Gas Industry SIGTTO guidelines and recommendations; ignored Sandia National Laboratories guidelines and recommendations; did not account for many LNG potential hazards in the waterway, air and shoreline; failed to consider or mention hazard issues listed in the Coos County Natural Hazards Mitigation Plan; and included no plans for handling tsunami's and earthquakes.

- Emergency Response is inadequate with most Emergency Responders located in the Hazard Zones of Concern of the Facility and Tanker transit.

PROPOSED LNG FACILITY / VESSEL TRANSITS VIOLATE INDUSTRY GUIDELINES FOR SAFETY (As noted above on pages 38 and 39)

Jordan Cove Energy Project | **M&N Project No. 6753**
Jordan Cove LNG Terminal | **Document No. 6753RP0002 Rev: 0**
Shoreline Erosion Study - Recommendation #15 | **Page 9 of 25**

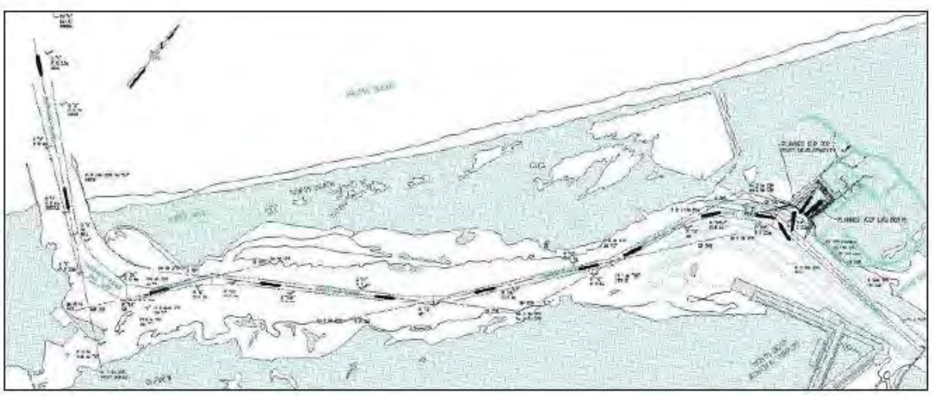


Figure 4-1: Location Map

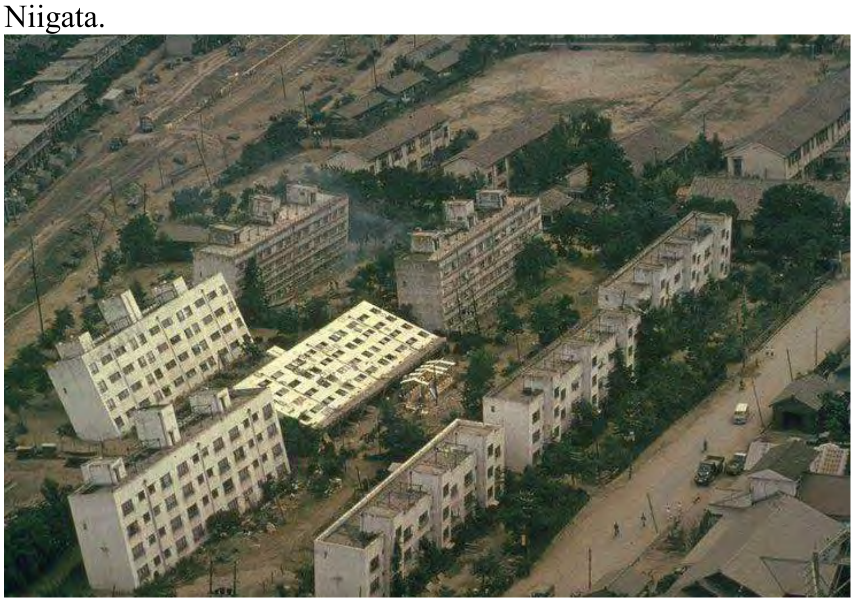
To insure the safety and security of the LNG project, big steps making new rules would be essential. Security for the vessels, facility, and the pipeline would likely shut down public use of those areas influenced, along the ROW, North Spit access road, and in and along the channel. The ship will be docked at the terminal approximately 17 - 22 hours to completely load its cargo according to the applicant. The time could be more depending on the change of tide, weather, harbor clearance, etc. Security for the vessel would not only be the 90 minutes to 2 hours it would take for travel in or out of Port, but the entire time of dockage. Using the applicant's estimate of 120 LNG vessel visits per year, the amount of time safety and security measures would be increased is alarming. A 24-hour turn around, which would include night operations, utilizing the applicants estimated 120 transits, would need 240 days for LNG commercial use of the bay. More likely, a 24-hour turn around would be necessary to avoid risks of nighttime operations. Tugboat operators require good visibility to pull laden vessels in the channel and using high tides would be the only way the deep drafted LNG vessels could be moved. If this scenario became the standard of operation, it is easy to see 300 or even as much as 365 days per year would be required and new safety and security limits would need to be enforced pretty much all the time. **This future shows a major detrimental impact to present recreational and commercial users of the seven and one-half miles of Coos Bay and that profound change cannot be mitigated.**

Additional details concerning this have been explained more fully on pages 38 to 40 above.

16,922 people live in the hazardous zones of concern according to the former Jordan Cove Export Final EIS (page 4-1031) under CP13-483-000/CP13-492-000, and yet there is little concern given for their safety. Trees and burnable scrub brush cover our area. Secondary fires will be paramount and most of our emergency responders are located in the LNG hazard zones of concern. The Coos Bay area has one hospital, it does not have a ―Burn Unit." We have yet to see an emergency response plan on how the medical response to even a minor LNG hazardous event could be handled in light of our area's obvious insufficiency of appropriate medical facilities and personnel. This was just one of many concerns that were raised in scoping comments to FERC that have yet to be addressed.

1964 Niigata earthquake, Japan

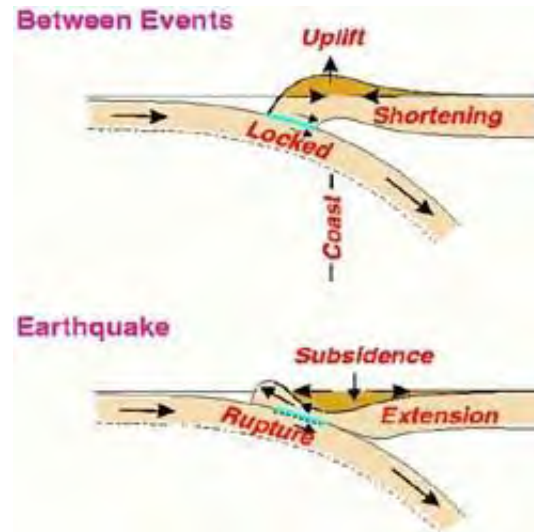
The Niigata earthquake of June 16, 1964 had a magnitude of 7.5 and caused severe damage to many structures in Niigata. The **destruction was observed to be largely limited to buildings that were founded on top of loose, saturated soil deposits**. (*General report on the Niigata earthquake 1964*). A tsunami, triggered by movement of the sea floor associated with the fault rupture, totally destroyed the port of Niigata.



During the Niigata earthquake a remarkable ground failure occurred near the Shinano riverbank where the Kawagishi-cho apartment buildings suffered bearing capacity failures and tilted severely. (Photo above.)[142]

[142] http://www.ce.washington.edu - http://www.ce.washington.edu/~liquefaction/html/quakes/niigata/niigata.html

It is highly unlikely that the Jordan Cove Facility (Built on 30+ feet of fill) along with its Pacific Connector Gas Pipeline, would be able to withstand such ground movements. In addition, floating objects, barges, vessels, etc, can be a significant issue in a tsunami along with bridges that would be needed to evacuate the area. ODOT estimates they'll need $3 billion to prepare Oregon's bridges to withstand a major earthquake along the coast, far more money than they have. **Without such repairs, a 9.0 temblor would leave U.S. Highway 101 impassable and state highways 38 and 42 in disrepair.**



The Pacific Connector Pipeline

The Pacific Connector Gas Pipeline (PCGP) is an approximately 229-mile, 36-inch high-pressure gas pipeline operating at 1,600 PSI. PCGP is proposed to transport 1 billion cubic feet a day of gas to the Coos Bay LNG site from a connect at Malin, Oregon. **The hazard zone for this pipeline goes out approximately an 800 to 1,000 foot radius from the center of the pipe,[143] up to 2,000 feet across, which impacts many landowners who may not even be aware they are living or have property in a pipeline hazard zone**. Pacific Connector appears only to be notifying landowners whose property is impacted directly by proposed gas pipeline itself.

Even though construction would impact 95+ feet, landowners would only be compensated for a 50 foot permanent easement and <u>there is no compensation listed for hazard zone property value devaluation.</u>

The freshwater streams crossed by proposed pipeline route include 6 major subbasins of rivers in southern Oregon, the Coos, Coquille, South Umpqua, Upper Rogue, Upper Klamath and Lost River subasins. **Most of the major streams, and many of the minor streams crossed, contain salmon and steelhead, some of which are federally listed as threatened fish species.**

It could take many decades for conditions within these wetlands to restore to preconstruction conditions.

For the sake of the thousands of people who are at risk in the Coos Bay area, we ask Coos County and DSL to require a thorough independent review before considering any approval of Jordan Cove's Removal/Fill Clean Water and Coastal Zone Management permit applications, particularly since the dredging of 6.3 million cubic yards (5.7 mcy for marine terminal + .6 mcy for navigational alterations) would not only change drastically the water velocity and flow of the tidal cycle in and out of the Coos Bay, but could contribute to additional dire consequences in the area in the event of an earthquake and/or tsunami. In addition, the proposal would mean the removal of an 100 foot high forested sand dune that is currently one of the few safety areas in this part of the North Spit where one could go to for protection should a tsunami occur.

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[143] GRI-00/0189 / C-FER Report 99068, ―*A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*" Topical Report prepared by Mark J Stephens, C-FER Technologies, for Gas Research Institute, Contract No 8174, Oct 2000

CONCLUSION

Permit Should Be Denied.

There is no way as citizens we can go through the volume of permit material that is being thrown at us on a weekly basis in order for us to write substantive comments on these various permit applications for Jordan Cove. The land use processes on the Jordan Cove project have yet to be completed and those CUP permits approved. Why is the State and Coos County processing their permits prematurely? Citizens are having to prepare briefs for appeals on land use decisions while at the same time write comments to State and Federal Agencies who have decided to process their permits on the Jordan Cove project or review their regulations that would affect the project, all at the same time. This is a clear violation of the National Environmental Policy Act (NEPA).

In addition, Federal regulators have ruled Oregon's plan for reducing coastal pollution due to runoff from logging, agriculture, stormwater runoff and other sources is insufficient. The January 30, 2015 decision[144] by the National Oceanic and Atmospheric Administration and the U.S. Environmental Protection Agency found Oregon too weak in four forest management areas:

- Riparian protection for medium and small fish-bearing streams and non fish-bearing streams
- Practices that reduce runoff from old, unused forest roads
- Practices to reduce runoff from landslide-prone areas
- Assurances that herbicides are properly applied to reduce impact on waterways.

Dennis McLerran, region 10 administrator for the EPA, said in a news article[145] that the agencies are working with Oregon to create a timeline for the state to address its shortcomings. How can we be assured that proper reviews are being done on the Jordan Cove project and if Oregon's program is currently in line with the Federal guidelines?

Jordan Cove submitted a very incomplete application which has forced us citizens have to bring up and critique issues that have not been properly presented. The application is not in compliance with the Coos County Ordinance and Coos Bay Estuary Management Plan and should be denied.

Sincerely,

/s/ Jody McCaffree

Jody McCaffree

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[144] *NOAA/EPA Finding That Oregon Has Not Submitted A Fully Approvable Coastal Nonpoint Program* – January 30, 2015
http://coast.noaa.gov/czm/pollutioncontrol/media/ORCZARAdecision013015.pdf

[145] *—Feds reject Oregon's coastal pollution plan, could impose financial sanctions"* January 30, 2015 - By Kelley House
http://www.oregonlive.com/environment/index.ssf/2015/01/feds_reject_oregons_coastal_po.html

Index for Exhibits

October 14, 2019

McCaffree / Citizens For Renewables / CALNG

For Jordan Cove / Pacific Connector

HBCU-19-003

<u>Exhibit 1</u>: May 7, 2018 the Federal Aviation Administration (FAA) issued 13 NOTICES OF PRESUMED HAZARD on components of the Jordan Cove LNG project,

<u>Exhibit 2</u>:
- Oregon Dept of State lands (DSL) March 5, 2019 notice that they extended their review time on the Jordan Cove project's removal-fill permit application until September 2019; and
- April 10, 2019 DSL *Overview of Decision Process and Need for Additional Information request* issued to Jordan Cove Re: DSL Removal-Fill Permit Application No. 60697-RF.

<u>Exhibit 3</u>: March 11, 2019, Oregon DEQ request for additional information from the Jordan Cove Project which included, among other things that the project conduct a benthic macroinvertebrate assessment to comply with the Biocriteria water quality standard (Oregon Administrative Rule 340-0410-0011).

<u>Exhibit 4</u>: May 6, 2019 News Release of the DEQ denial of Jordan Cove's application for 401 Water Quality Certification.

<u>Exhibit 5</u>: December 16, 2014 Public Comment by **Barbara Gimlin** on Jordan Cove Energy Project, L.P., Draft Environmental Impact Statement expressing concerns with respect to **contaminated soils on the Jordan Cove property** under CP13-483-000 via CP07-444-000.

<u>Exhibit 6</u>: February 13, 2015 Public Comment by **Barbara Gimlin** on Jordan Cove Energy Project, L.P., DEQ Water Quality permit process under FERC CP13-483-000.

<u>Exhibit 7</u>:
- Oct 15, 2014 Motion to Intervene Out of Time by **Clausen Oyster Company and Lilli Clausen** expressing concerns with **pipeline and sediment impacts to their Oysters**
- Feb 28, 2015 Motion to Intervene Out of Time by **Coos Bay Oyster Company and Jack Hampel** expressing concerns with **pipeline and sediment impacts to their Oysters**.

<u>Exhibit 8</u>: Feb 21, 2014 **Motion to Intervene Out of Time by Clam Diggers Association of Oregon** expressing concerns with LNG project **sedimentation and estuary impacts on clams**

<u>Exhibit 9</u>: ***Potential Impact of Jordan Cove LNG Terminal construction on the Nursery Habitat of Dungeness crab*** by Sylvia Yamada Ph.D. January 2019 for DSL and oral comment outline provided on January 15, 2019 under APP0060697 at Salem Hearing.

<u>Exhibit 10</u>: Letter from Shon Schooler, Ph.D., Research Coordinator with the South Slough National Estuarine Research Reserve concerning Eelgrass (March 2019)

Exhibit 11: Select pages from ***Oregon Travel Impacts Statewide Estimates 1992 - 2017p Report***; June 2018 ; Dean Runyan Associates **(Coos County Impacts)**
http://www.deanrunyan.com/doc_library/ORImp.pdf

Exhibit 12: May 21, 2010 and **Sept 17, 2007 testimony from Ron Sadler** placed into Jordan Cove and Pacific Connector Conditional Land Use Permit processes in Coos County concerning **sedimentation impacts in the Coos Estuary**.

Exhibit 13:

- ODFW – **Threatened / Endangered Species List** http://www.dfw.state.or.us/wildlife/diversity/species/threatened_endangered_candidate_list.asp
- **NOAA – Oregon Coast Coho protected species:** http://www.westcoast.fisheries.noaa.gov/protected_species/salmon_steelhead/salmon_and_steelhead_listings/coho/oregon_coast_coho.html
- **NOAA - Green Sturgeon protected species:** http://www.westcoast.fisheries.noaa.gov/protected_species/green_sturgeon/green_sturgeon_pg.html
- **NOAA – Pacific Eulachon protected species** http://www.westcoast.fisheries.noaa.gov/protected_species/eulachon/pacific_eulachon.html
- **ESA listed Marine Mammals** http://www.westcoast.fisheries.noaa.gov/protected_species/marine_mammals/esa.html
- **ESA listed Sea Turtles** http://www.westcoast.fisheries.noaa.gov/protected_species/sea_turtles/marine_turtles.html
- **Point Reyes bird's-beak** – Oregon Dept of Agriculture - Endangered http://www.oregon.gov/oda/shared/Documents/Publications/PlantConservation/CordylanthusMaritimusPalustrisProfile.pdf

Exhibit 14:

- Evidence of Shell's Sakhalin II LNG project in Russia and the Environmental Impacts to Avina Bay along with devastating upland impacts.
- Pipeline Impacts from Shell's Sakhalin II LNG project in Russia
- Fortune article "Shell shakedown" By Abrahm Lustgarten, Feb 1, 2007

Exhibit 15:

- Nation & World - ***Ocean salmon seasons in jeopardy off southern Oregon;*** Originally published March 5, 2018; The Associated Press https://www.seattletimes.com/nation-world/ocean-salmon-seasons-off-southern-oregon-coast-in-jeopardy/
- ***West Coast senators join call for salmon disaster declaration****;* Saphara Harrell - The Umpqua Post; Jun 13, 2017 http://theworldlink.com/news/local/west-coast-senators-join-call-for-salmon-disaster-declaration/article_3690f87f-44b8-5f19-a385-7557776543b0.html

Exhibit 16: **Oregon Shorebird Festival Bird List** Compiled from all field trips August 26-28, 2011

Exhibit 17: ***7,500 songbirds killed at Canaport gas plant in Saint John*** - Migrating birds, some possible endangered species, flew into gas flare CBC News Posted: Sep 17, 2013 http://www.cbc.ca/news/canada/new-brunswick/7-500-songbirds-killed-at-canaport-gas-plant-in-saint-john-1.1857615

Exhibit 18: The Irish Times - ***Gas flaring at Corrib plant 'frightening', says resident***; Jan 1, 2016 ; By Lorna Siggins; http://www.irishtimes.com/news/ireland/irish-news/gas-flaring-at-corrib-plant-frightening-says-resident-1.2482377

Exhibit 19: Zoning Information for JCEP proposed dredging / fill sites within the Coos Estuary

Exhibit 20: November 27, 2017 Oregon LUBA-No. 2016-095 *Oregon Shores vs Coos County* Final Opinion and Order

Exhibit 21: March 9, 2017 Coos County file No. ACU-17-009 application for extended RV park at Boxcar Hill camping area.

Exhibit 22: Coos County File No. ACU-17-009 Notice of Decision and Staff Report for extended RV park at Boxcar Hill camping area.

Exhibit 23: Dec 4, 2018 letter to the FERC under Docket Nos. CP17-494-000 and CP17-495-000 adding to Service list Natalie Eades, Manager, Environment, Jordan Cove Energy Project L.P. Pacific Connector Gas Pipeline, L.P. / contact NEades@pembina.com

Exhibit 24:

- Articles about the 2004 LNG Explosion in the Algeria Liquefaction Industrial Zone.
- Five killed in Connecticut power plant blast February 7, 2010 10:06 p.m. EST

Exhibit 25: ***Geology of the Coos Estuary and Lower Coos Watershed*** from Partnership for Coastal Watersheds Report https://www.partnershipforcoastalwatersheds.org/geology-of-the-coos-estuary-and-lower-coos-watershed/

Exhibit 26: ***13-Year Cascadia Study Complete – And Earthquake Risk Looms Large*** http://oregonstate.edu/ua/ncs/archives/2012/jul/13-year-cascadia-study-complete-%E2%80%93-and-earthquake-risk-looms-large

Exhibit 27: Select pages from ***The Oregon Resilience Plan Reducing Risk and Improving Recovery for the Next Cascadia Earthquake and Tsunami***; Report to the 77th Legislative Assembly from Oregon Seismic Safety Policy Advisory Commission (OSSPAC); Feb 2013

Exhibit 28: Industrial Energy Consumers of America "***Excessive Liquefied Natural Gas (LNG) Exports To NFTA Countries Are Not In The Public Interest And Increase Natural Gas And Electricity Prices To Consumers***" - January 30, 2019

Exhibit 29: ***Limitations of the Haynes Inlet sediment transport study*** by Tom Ravens, Ph.D., Professor, Dept. of Civil Engineering University of Alaska, Anchorage

Exhibit 30: U.S. Coast Guard ***July 1, 2008, Water Suitability Assessment (WSA) Report*** for the Jordan Cove project.

Exhibit 31: ***Coos Bay Harbor Safety Plan*** by Coos Bay Harbor Safety Committee, February 2018

Exhibit 32: ***Coos Bay Channel Entrance - Distances and Buoy Markings***. Proximity of Channel Buoys to the Shoreline.

Exhibit 33: ***DEQ hits Clausen Oysters with $25,000 fine*** By Gail Elber, Staff Writer Aug 25, 2010https://theworldlink.com/news/local/deq-hits-clausen-oysters-with-fine/article_9fb57e0c-b070-11df-8cc0-001cc4c03286.html

Exhibit 34: FAA Memorandum Re: "***Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations";*** January 21, 2015

Exhibit 35: "*Hot Air"* Pilots say the Port of Portland's plans to sell land for a power plant next to the Troutdale Airport include a fatal flaw; April 22, 2015; Willamette Week http://www.wweek.com/portland/article-24594-hot_air.html

Exhibit 36: *"**Position Paper - Safety Concerns of Exhaust Plumes**"* -Prepared by: Federal Aviation Administration - Airport Obstructions Standards Committee Working Group; July 8, 2014

Exhibit 37: Potential Flight Hazards 8-22-13 AIM: *"7-5-15.* ***Avoid Flight in the Vicinity of Thermal Plumes (Smoke Stacks and Cooling Towers)"***

Exhibit 38: September 6, 2014 Newspaper **Ad announcing the 15th annual Coos Basin Salmon Derby** in Coos Bay, Oregon Sept 13 & 14th 2014

Exhibit 39: South Coast Basin - **Flow Restoration Priorities** for Recovery of Anadromous Salmonids in Coastal Basins

Exhibit 40: September 15, 2015 Jordan Cove Final EIS under CP13-483-000 et al pages 4-370 to 4-739 having to do with **Ballast Water**

Exhibit 41:

- North Spit listing in"**Top 10 Beach Strolls**" Sunset Magazine, Vol. 219, Issue 4, October 2007
- Coos Bay, Oregon listing in **50 Best Places to Live National Geographic Adventure Magazine** - September 2008

Exhibit 42: ***After a year of planning, Coos Bay has new marine patrol boat dock*** by KCBY; Wednesday, March 16th 2016; https://kcby.com/news/local/after-a-year-of-planning-coos-bay-has-new-marine-patrol-boat-dock

Exhibit 43: June 24, 2015 Letter from attorney's Motschenbacher and Blattner LLP concerning **Jordan Cove leasing the Boxcar Hill Campground**.

Exhibit 44: Study outlines threat of ***ocean acidification to coastal communities in the U.S***.; Oregon State University; Feb 23, 2015 http://today.oregonstate.edu/archives/2015/feb/study-outlines-threat-ocean-acidification-coastal-communities-us

Exhibit 45: ***Vulnerability and adaptation of US shellfisheries to ocean acidification****;* By Julia A. Ekstrom; Lisa Suatoni; Sarah R. Cooley; Linwood H. Pendleton; George G. Waldbusser; Josh E. Cinner; Jessica Ritter; Chris Langdon; Ruben van Hooidonk; Dwight Gledhill; Katharine Wellman; Michael W. Beck; Luke M. Brander; Dan Rittschof; Carolyn Doherty; Peter Edwards; and Rosimeiry Portela; Perspective in Nature Climate Change; Published on-line – Feb 2015

Exhibit 46: ***Oysters on acid: How the oceans's declining pH will change the way we eat*** ; By H. Claire Brown; November 28th, 2017; https://newfoodeconomy.org/ocean-acidification-oysters-dungeness-crabs/

Exhibit 47:

- **Oregon and California crabbers sue fossil fuel companies** Updated Nov 27, 2018; Posted Nov 26, 2018 https://www.oregonlive.com/pacific-northwest-news/index.ssf/2018/11/oregon_and_california_crabbers.html
- Superior Court of the State of California ***Pacific Coast Federation of Fishermen's Association, Inc –vs- Cheron Corp; Chevron U.S.A. Inc, Exxon Mobil Corp et.al.*** Petitioners Complaint under Case CGC-18-571285.
- United States District Court Western District of Washington at Seattle ***Columbia Riverkeeper et. al.-v- Scott Pruitt, et. al*** Order Re: Motions for Summary Judgment under Case No C17-289RSM

Exhibit 48: Williams CR, Dittman AH, McElhany P, et al. ***Elevated CO2 impairs olfactory-mediated neural and behavioral responses and gene expression in ocean-phase coho salmon (Oncorhynchus kisutch)***. Glob Change Biol. 2018;00:1–15. https://doi.org/10.1111/gcb.14532 November 2018

Exhibit 49: "***Northwest B.C.'s LNG boom is already a bust for some***" (with video) *Heated economy drives up prices and drives out tenants;* By Gordon Hoekstra, Vancouver Sun November 5, 2014 http://www.vancouversun.com/business/energy/Northwest+boom+already+bust+some/10326811/story.html?__lsa=0882-6c5e

Exhibit 50: ***"B.C. LNG work camps concern for northern towns, say mayors"*** *Two northern B.C. mayors share their city's struggle with the impending influx of temporary workers;* By Radio West, CBC News Posted: Feb 02, 2015 http://www.cbc.ca/news/canada/british-columbia/b-c-lng-work-camps-concern-for-northern-towns-say-mayors-1.2938393

Exhibit 51: *Dark side of the Boom"* By Sari Horwitz; The Washington Post; Sept 28, 2014 http://www.washingtonpost.com/sf/national/2014/09/28/dark-side-of-the-boom/

Exhibit 52: November 12, 2014 notice from the Brotherhood of Electrical Workers 932 that covers proposed Jordan Cove subsistence fees for workers.

<u>Exhibit 53</u>: **Alternative LNG terminal locations**

<u>Exhibit 54</u>: ***Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world*** ;By Claudia Cattaneo; February 16, 2018; http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

<u>Exhibit 55</u>: ***Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing***; Oil Change International; Jan 2018; http://priceofoil.org/2018/01/11/jordan-cove-lng-and-pacific-connector-pipeline-greenhouse-gas-emissions/

<u>Exhibit 56</u>: Select pages from ***IGU 2018 World LNG Report*** - 27th World Gas Conference Edition

<u>Exhibit 57</u>: ***Current Removal-Fill Permit Applications*** in Coos County – Not a complete listing

<u>Exhibit 58</u>: August 18, 2015 **letter from United States Environmental Protection Agency Region 10** - concerning maintenance dredging disposal availability.

<u>Exhibit 59</u>: ***The impact of channel deepening and dredging on estuarine sediment concentration*** D.S. vanMaren n, T.vanKessel, K.Cronin, L.Sittoni - Coastal and Marine Systems 95(2015)1–14 Deltares, Delft, the Netherlands

<u>Exhibit 60</u>: ***The effects of marine gravel extraction on the macrobenthos: Results 2 years post-dredging*** A.J. Kenny, H.L. Rees ; Marine Pollution Bulletin ; Volume 32, Issues 8–9, August–September 1996, Pages 615-622
https://www.sciencedirect.com/science/article/pii/0025326X96000240?via%3Dihub

<u>Exhibit 61</u>: ***Seagrasses, Dredging and Light in Laguna Madre, Texas, U.S.A.***
Christopher P. Onuf - National Biological Survey, National Wetlands Research Center, Campus Estuarine, Coastal and Shelf Science; Volume 39, Issue 1, July 1994, Pages 75-91
https://www.sciencedirect.com/science/article/pii/S027277148471050X?via%3Dihub

<u>Exhibit 62</u>: ***Dredging related metal bioaccumulation in oysters***
L.H. Hedge , N.A. Knott, E.L. Johnston; Marine Pollution Bulletin; Volume 58, Issue 6, June 2009, Pages 832-840
https://www.sciencedirect.com/science/article/pii/S0025326X09000472?via%3Dihub

<u>Exhibit 63</u>: ***Shell shock*** *,* June 14, 2010, By Nate Traylor, Staff Writer - The World
http://theworldlink.com/news/local/shell-shock/article_389a9be8-77dc-11df-9127-001cc4c03286.html

<u>Exhibit 64</u>:
A MODEL FOR SIZING HIGH CONSEQUENCE AREAS ASSOCIATED WITH NATURAL GAS PIPELINES - *TOPICAL REPORT* Prepared by Mark J. Stephens,
C-FER Technologies, Oct 2000

Exhibit 65:
November 6, 2017 **DOGAMI comments related to Geologic Hazards** and the Proposed Jordan Cove LNG terminal and Pacific Connector Gas Pipeline.

Exhibit 66:
January 11, 2015 Public Comment by Barbara Gimlin*, **Intertidal Flats Mitigation Proposed for Kentuck Slough*** - Jordan Cove Energy Project Joint Permit Applications
U.S. Army Corps of Engineers/Oregon Department of State Lands

Exhibit 67:
Supplement to Technical Memorandum - ***Jordan Cove LNG Facility Tsunami Hydrodynamic Modeling*** – January 24, 2014

Exhibit 68: June 25, 2014 DEQ Warning letter issued to Jordan Cove for violations that occurred at the Ingram Yard property on May 8, 2014, along with the follow-up that also occurred.

Exhibit 69: ***Where have the wild birds gone? Study counts 3 billion fewer than 1970, stunning scientists*** By Seth Borenstein and Christina Larson AP Science Writers
Sep 19, 2019 https://theworldlink.com/news/science/where-have-the-wild-birds-gone-study-counts-billion-fewer/article_a626eed1-2063-52e5-9e5e-a6c7a903f593.html

Exhibit 70: *Even Without Ears, Oysters Can Hear Our Noise Pollution* Study shows that certain frequencies of noise cause oysters to clam up; By Jason Daley; smithsonian.com; October 27, 2017; https://www.smithsonianmag.com/smart-news/earless-oysters-can-still-hear-our-noise-pollution-180966990/

Exhibit 71: *Review of noise impacts on marine mammals yields new policy* Review of noise impacts on marine mammals; March 13, 2019 ;
https://www.sciencedaily.com/releases/2019/03/190313143307.htm

Exhibit 72: Oregon Dunes National Recreation Area map and guide
https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd595822.pdf

Exhibit 73: *UTVs to 'takeover' Box Car Hill this weekend* NICHOLAS A. JOHNSON - The World Jun 27, 2019

Exhibit 74: Communications with the FAA.

Exhibit 75: Diagram of Weyerhaeuser Land Fill areas on South Dunes property.

Exhibit 76: Exhibit 3: Testimony and Exhibits submitted by Professor Jerry Havens to the PHMSA and FERC on

Exhibit 77: *WILLIAMS COMPANIES FAILED TO PROTECT EMPLOYEES IN PLYMOUTH LNG EXPLOSION* The natural gas company eyeing other Northwest projects has a history of unsafe work conditions. Author: Tarika Powell; June 3, 2016

Exhibit 1

Index for Exhibits

July 9, 2019
McCaffree / Citizens For Renewables / CALNG
For Rebuttal Comments re Jordan Cove / Pacific Connector
REM-19-001

Exhibit A: Corrected Table of Contents submitted for Comments submitted on June 24, 2019 under REM-19-001

Exhibit B: ECONorthwest October 16, 2006 *Forecast of the Net Economic Benefits of a Proposed LNG* [Import] *Terminal in Coos County, Oregon*

Exhibit C: September 12,. 2012 Answer filed with the U.S. Department of Energy Concerning Jordan Cove's LNG Export Application under FE Docket No. 12–32–LNG concerning problems with ECONorthwest analysis.

Exhibit D: April 1, 2019, Comment by Jerry Havens, Distinguished Professor of Chemical Engineering at University of Arkansas, on the FERC DEIS under CP-17-494 and CP-17-495. Concerns public safety hazards being underestimated at the proposed Jordan Cove LNG terminal

Exhibit E "*Scientists say public safety hazards at Jordan Cove LNG terminal in Coos Bay are underestimated"* by Ted Sickinger; The Oregonian; January 16, 2015

Exhibit F: June 7, 2016, article, "*Explosive LNG issues grab PHMSA's attention" by* E&E reporter, Jenny Mandel.

Exhibit G: 5-2-2019 Department of Transportation Pipeline and Hazardous Materials Safety Administration [Docket No. PHMSA-2019-0087] Bulletin regarding *Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards*

Exhibit H: Omitted due to computer glitch. (NOTE *See Sept 9, 2019 Exhibit 11*)

Exhibit I: The World – Coos Bay **UTVs to 'takeover' Box Car Hill this weekend**
NICHOLAS A. JOHNSON - The World, June 27, 2019
https://theworldlink.com/news/local/utvs-to-takeover-box-car-hill-this-weekend/article_c3258d6e-e77f-5073-b28c-8d2a657c7186.html

Exhibit J: Page 2435 from NB JCEP Rebuttal Comment filed on 6-10-2019 showing Jordan Cove plans for Boxcar Hill Campground.

Exhibit 2

MEMORANDUM TO: Office of the Secretary

FROM: U.S. Coast Guard
[Posted by Ghanshyam Patel, FERC staff]

SUBJECT: Letter of Recommendation (LOR) for the Jordan Cove LNG Project - Docket No. CP17-495-000

DATE: June 1, 2018
[LOR dated May 10, 2018]

Please place the attachment in the public files for the Jordan Cove LNG Project under Docket No. CP17-495-000.

The attachment contains:

- U.S. Coast Guard's LOR
- LOR Analysis (Enclosure 1)
- April 24, 2009 LOR (Enclosure 2)
- Waterway Suitability Report (Enclosure 3)

U.S. Department of
Homeland Security

United States
Coast Guard

Captain of the Port
U. S. Coast Guard
Sector Columbia River

2185 SE 12th Place
Warrenton, Oregon 97146-9693
Staff Symbol: s
Phone: (503) 861-6211

16611
May 10, 2018

Director of Gas Environment and Engineering, PJ 11
Attn: Mr. Rich McGuire
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Dear Mr. McGuire:

This Letter of Recommendation (LOR) is issued pursuant to 33 Code of Federal Regulations (CFR) 127.009 in response to the Letter of Intent submitted by Jordan Cove Energy Project. L.P. (Jordan Cove) on January 9, 2017. Jordan Cove proposes to construct and operate the Jordan Cove LNG facility in Coos Bay, Oregon from which Liquefied Natural Gas (LNG) is proposed to be transferred in bulk to a vessel for export. This LOR conveys the Coast Guard's recommendation on the suitability of the Coos Bay Channel for LNG marine traffic as it relates to safety and security. In addition to meeting the requirements of 33 CFR 127.009, this LOR fulfills the Coast Guard's commitment for providing information to your agency under the Interagency Agreement signed in February 2004.

After reviewing the information in the applicant's Letter of Intent (LOI) and Waterway Suitability Assessment (WSA) with subsequent annual updates and completing an evaluation of the waterway in consultation with a variety of state and local port stakeholders, I recommend that the Coos Bay Channel be considered suitable for LNG marine traffic. My recommendation is based on review of the factors listed in 33 CFR 127.007 and 33 CFR 127.009. The reasons supporting my recommendation are outlined below.

On November 1, 2017, I completed a review of the WSA for the Jordan Cove Energy Project, submitted to the Coast Guard by KSEAS Consulting on behalf of Jordan Cove in February 2007. This review was conducted following the guidance provided in U.S. Coast Guard Navigation and Vessel Inspection Circular (NVIC) 01-2011, dated January 24, 2011. In conducting this review and analysis, I focused on the navigation safety and maritime security aspects of LNG vessel transits along the affected waterway. My analysis included an assessment of the risks posed by these transits and validation of the risk management measures proposed by the applicant in the WSA. During the review, I consulted a variety of stakeholders including the Area Maritime Security Committees, Harbor Safety Committees, State representatives, Pilot Organizations, and local emergency responders.

Based upon a comprehensive review of Jordan Cove's WSA, and after consultation with State and Local port stakeholders, I recommend that the Coos Bay Channel be considered suitable for accommodating the type and frequency of LNG marine traffic associated with this project.

The attached LOR Analysis contains a detailed summary of the WSA review process that has guided this recommendation. It documents the assumptions made during the analysis of Jordan Cove's WSA. It discusses details of potential vulnerabilities and operational safety and security measures that were analyzed during the review. The portion of the LOR Analysis which addresses matters that affect maritime security is marked as Sensitive Security Information and is withheld from distribution.[1] The LOR Analysis sets forth the navigational safety and maritime security resource gaps that currently exist in, on, and adjacent to the waterway, including the marine transfer area of the proposed facility, and which, to the extent allowable under FERC's existing legal authority, may be addressed in its Commission Order if one is issued. To the extent implementation of specific mitigation measures fall outside the scope of FERC's legal authority, the applicant is expected to examine the feasibility of implementing such mitigation measures, in consultation with the Coast Guard and State and Local agencies as applicable.

This recommendation is provided to assist in the Commission's determination of whether the proposed facility should be authorized. This Letter of Recommendation is not an enforceable order, permit, or authorization that allows any party, including the applicant, to operate a facility or a vessel on the affected waterway. Similarly, it does not impose any legally enforceable obligations on any party to undertake any future action be it on the waterway or at the proposed facility. It does not authorize, nor in any way restrict, the possible future transit of properly certificated vessels on the Coos Bay Channel. As with all issues related to waterway safety and security, I will assess each vessel transit on a case by case basis to identify what, if any, safety and security measures are necessary to safeguard the public health and welfare, critical marine infrastructure and key resources, the port, the marine environment, and vessels. In the event the facility begins operation and LNG vessel transits commence, if matters arise concerning the safety or security of any aspect of the proposed operation, a Captain of the Port Order could be issued pursuant to my authority under the Ports and Waterways Safety Act of 1972, as amended by the Port and Tanker Safety Act of 1978, 33 U.S.C. § 1221 – 1232, among other authorities, to address those matters.

Please note that Enclosures (4) is Sensitive Security Information (SSI) and shall be disseminated, handled and safeguarded in accordance with 49 CFR Part 1520, "Protection of Sensitive Security Information."

If you have any questions on this recommendation, my point of contact is Lieutenant Commander Laura Springer. She can be reached at the address listed above, by phone at (503) 209-2468, or by email at Laura.M.Springer@uscg.mil.

Sincerely,

W. R. TIMMONS,
Captain, U. S. Coast Guard
Captain of the Port, Sector Columbia River

Enclosure (1) LOR Analysis
(2) LOR issued by Sector Portland on April 24, 2009
(3) U.S.C.G.'s Waterway Suitability Report for the Jordan Cove Energy Project
(4) LOR Analysis (SSI Portion)

[1] Documents containing SSI may be made available upon certification that the requestor has a need to know and appropriate document handling and non-disclosure protocols have been established.

Copy: Commander, Coast Guard District Thirteen (dp)
Commander, Pacific Area (PAC-54)
Commandant (CG-OES), (CG-ODO), (CG-FAC), (CG-741), (CG-CVC), (CG-ENG), (LNGNCOE)
Marine Safety Center (CG MSC)
Jordan Cove

UNITED STATES COAST GUARD

Jordan Cove LNG

ANALYSIS SUPPORTING THE LETTER OF RECOMMENDATION ISSUED BY COTP SECTOR COLUMBIA RIVER ON MAY 10, 2018

Enclosure (1)

Introduction

1. This analysis is a supplement to my Letter of Recommendation (LOR) dated May 10, 2018, that conveys my recommendation on the suitability of the Coos Bay Ship Channel for liquefied natural gas (LNG) marine traffic associated with the Jordan Cove LNG (JCLNG) export terminal project Coos Bay, Oregon. It documents the processes followed in analyzing JCLNG's Waterway Suitability Assessment (WSA) and the suitability of the waterway for LNG marine traffic.

2. For the purposes of this analysis, the following assumptions were made:

   a. The applicant is fully capable of, and would fully implement, any and all risk management measures identified in their WSA.
   b. The conditions of the port identified in the WSA fully and accurately describe the actual conditions of the port at the time of the WSA submission.
   c. The conditions of the port have not changed substantially during the analysis process.
   d. The applicant will fully meet all regulatory requirements including the development and submission of a Facility Security Plan, Emergency Manual, and Operations Manual.

3. The Port of Coos Bay is a deepwater port located in Coos Bay, Oregon on the Pacific Coast of the United States. The Port of Coos Bay offers easy access to Asian markets and facilitates the international movement of goods between the United States and Asia. The Port of Coos Bay is managed under the jurisdiction of the Portland Navigation District and has an authorized channel depth of 37 feet. The channel width is 300 nominal feet. The principal exports are logs, wood chips, lumber, and plywood. The Port of Coos Bay is currently conducting a feasibility study to examine widening and deepening its ship channel.

4. The Port of Coos Bay is approximately 173 nautical miles south of the Columbia River and 367 miles north of the entrance to San Francisco Bay. The Port has seen declining arrivals and is not currently heavily trafficked.

5. Inbound and outbound traffic density in the Port of Coos Bay is currently minimal. In the summer months and during fishing season there are a number of commercial fishing vessels working in the region. The maximum anticipated LNG Carrier port calls per year is expected to be around 120. These projections are based on a maximum nominal LNG output of 7.8 MTPA. Other traffic transiting through the Port of Coos Bay include fishing vessels, recreational vessels, and towing vessels.

6. The Terminal will be sited at the north end of the Coos Bay Channel near Jordan Cove. All Terminal facilities will be located within an approximately 200-acre parcel of land. The approximate locations of the coordinates of the facility are: 43 degrees-25.5' North and 124 degrees 15.7' West.

7. The U.S. Coast Guard regulates the port under the Maritime Transportation Security Act (MTSA), Security and Accountability for Every Port Act (SAFE Port Act), Ports and Waterways Safety Act (PWSA) and other laws applicable to maritime safety and security. U.S. Coast Guard regulated facilities in the area include chip terminals and fuel transfer facilities.

8. Ships entering or departing Coos Bay require a pilot. The Coos Bay Pilots are state licensed Oregon pilots responsible for ensuring the safe transit of vessels transiting through the Port of Coos Bay. They handle approximately 50 vessel transits through the Port of Coos Bay each year.

9. In order to support operations associated with the facility, the applicant will provide additional towing vessels as outlined in their WSA. All tractor tugs must be at least 80 Ton Astern Bollard or larger and equipped with Class 1 Fire Fighting equipment.

10. The applicant established an emergency response planning group in preparation for facility construction and operation in 2006. This group is tasked with education and preparedness concerning this facility. It must be noted that there are schools located in the zones of concern.

Impact to Coast Guard Operations

1. The U.S. Coast Guard is responsible for screening LNG Carriers transiting from foreign ports prior to arrival and will screen all vessels in accordance with existing policies and procedures. The vessels calling on the facility will be foreign flagged and the flag state is yet to be determined. I do not intend to require additional government conducted safety inspections beyond those which already apply to deep draft LNG vessels.

2. Facility and vessel inspection activities will be supported by Marine Safety Unit Portland personnel.

3. Limited access areas (LAA) associated with the project have yet to be established. Sector Columbia River will use risk based decision making and work with existing policy to determine the appropriate LAAs. The proposed LAA in enclosure (3) was not put out for regulatory review and is not in effect.

4. LNG is not considered oil and all vessels calling on the facility will be required to comply with non-tank vessel response plan requirements. The applicant is highly encouraged to work with the Area Committees established under the National Contingency Plan to address issues associated with response in Coos Bay.

5. The Facility will be in the Sector Columbia River Captain of the Port Zone and falls under the purview of the Federal Maritime Security Coordinator who is also the Sector Columbia River Captain of the Port. Specific issues related to this are outlined in Enclosure (4).

Figure 1. Jordan Cove Conceptual rendering of facility

Decision Making Process

1. The following factors regarding the condition of the waterway, vessel traffic, and facilities upon the waterway, were taken into consideration during the LOR process. The processes used are detailed in this section.

2. To ensure all regulatory processes were met, Sector Columbia River took a systematic approach in the WSA validation process. To streamline and ensure transparency, Sector Columbia River worked with Jordan Cove, the Consulting Group KSEAS, and port partners though a series of ad hoc meetings and a one day workshop.

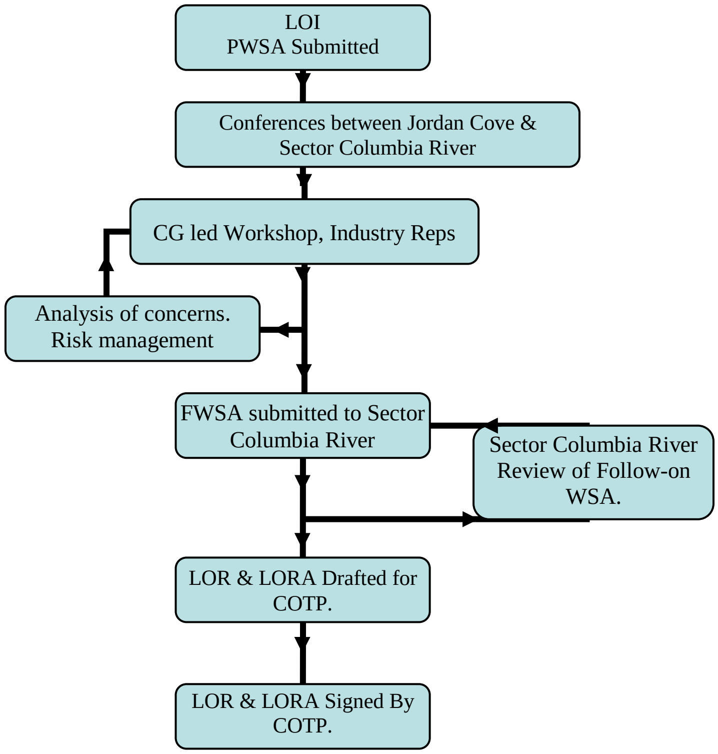

Figure 2 - LNG LOR Process (Sector Columbia River)

3. NVIC 01-2011 provides guidance on the review and validation of a WSA. Applying NVIC 01-2011's procedural framework, my staff held several in-house reviews of the WSA, and facilitated discussions during a workshop held in Coos Bay, OR on October 16, 2017. The workshop included a wide range of participants, including representatives from; the USCG; Coos Bay Pilots Association; Port Authorities, the State of Oregon and law enforcement agencies.

Members	Position/Role
LCDR Laura Springer	Waterways Management Division Chief, MSU Portland
LCDR Ben Crowell	Surface Operations, Sector North Bend
LCDR Andrew Madjeska	Incident Management Division Chief, Sector Columbia River
LCDR Xochitl Castaneda	District Thirteen Prevention
Ms. Deanna Henry	Oregon Department of Energy
George Wales	Coos Bay Pilots
Richard Dybevik	Roseburg Forest Products
Doug Strain	Coos Bay Sheriff
Jim Brown	North Bend Fire Department
Doug Eberlein	Coos Bay Response Co-op (CBRC)
LT Ethan Lewallen	USCG LNG NCOE

Table 1 – Jordan Cove WSA Team 1 Nov 2017 (Port of Coos Bay)

4. The participants of this "ad-hoc" workshop, recommended by NVIC 01-2011, utilized their expertise on the physical characteristics and traffic patterns of the waterway, as well as their respective specialty knowledge of the marine environment, LNG, safety, security, and facility operations, to analyze the suitability of the waterway to support LNG marine traffic associated with JCLNG.

5. Participants considered the changes in the area's safety and security dynamics which may result from the introduction of LNG ship traffic associated with the JCLNG Project. Jordan Cove used the American National Standards Institute (ANSI)/American Petroleum Institute (API) Standard 780 Security Risk Assessment (SRA) Methodology, as the basic approach for assessing risk. The standard was published in June of 2013 as a U. S. standard for security risk assessments on petroleum and petrochemical facilities. The standard is a tool used to evaluate all security risks associated with petroleum and petrochemical infrastructure and operations, and assists owners and operators through the process of conducting thorough and consistent SRAs. For security purposes, participants considered potential threats and consequences of intentional act of aggression to the facility and developed security measures to mitigate the risks.

    a. Please see Enclosure (4) if you have a need to know concerning the results of this

6. During the above mentioned workshop held in Coos Bay, OR on October 16, 2017, the ad-hoc working group also evaluated safety factors including the potential impacts of groundings, collisions, and allisions and thoroughly examined the simulator data presented in the WSA.

7. Each of the recommended risk management measures from enclosure (7) of NVIC 01-2011 were considered. In the WSA workshop, additional risks and recommendations were discussed related to a Cascadia Subduction Zone Earthquake and associated implications for the facility and region if a laden vessel was tied up at the layberth.

8. The ad-hoc working group considered each scenario along each transit segment and evaluated the causes of accidental or intentional events. The workshop analyzed the contributing factors for each scenario and their likelihood of occurrence given the adequacy of safety and security layers.

9. Sector Columbia River followed the checklist found in NVIC 01-2011 during the review. Through this review, Sector Columbia River clarified certain points in the WSA to ensure that the document contained accurate information and that references were applicable. With the 2017 update to the WSA, Jordan Cove has satisfied the requirements of the LOR process.

10. Based on my review of the WSA completed on November 1, 2017, and input from state and local port stakeholders, and taking into account previously reviewed expansion projects, I recommend to the Federal Energy Regulatory Commission

that the waterway in its current state be considered suitable for the LNG marine traffic associated with the proposed project.

11. This recommendation is contingent upon the applicant completing all actions outlined in the Waterways Suitability Assessment as submitted, and actions associated with subsequent annual updates, and completing all actions outlined in the most current WSA and actions under the control of the applicant from the July 1, 2008, Waterway Suitability Report.

Waterway Conditions Adjacent to the Facility

1. **Depth of Water**. The channel is currently maintained at a 37' depth.
2. **Tidal Range**. The tides of Coos Bay are of the mixed semi-diurnal type with paired highs and lows of unequal duration and amplitude. The tidal range increases upstream to the City of Coos Bay and the time difference between peak tides at the entrance and City of Coos Bay is about 40-90 minutes, depending on the location. The head of the tide is located at River Mile 27 on both the Millicoma and South Fork Coos Rivers. The tidal range is 7.5 feet near the open sea channel and 6.7 feet at the entrance to Charleston Harbor.

Table 2 Tidal Datums, Coos Bay, OR NOAA Tide Stations 9432895, 9432879, and 9432780

Tide Level	Abbreviation	Tide Level (ft) North Bend	Tide Level (ft) Empire	Tide Level (ft) Charleston
Tide Station ID #		9432895	9432879	9432780
Latitude		43º **24.6'N**	43º **22.6'N**	43º **20.7'N**
Longitude		124º **13.1'W**	124º **17.8'W**	124º **19.3'W**
Extreme High Water	EHW	-	-	+10.5
Mean Higher High Water	MHHW	+8.4	+7.7	+7.6
Mean High Water	MHW	+7.8	+7.1	+7.0
Mean Sea Level	MSL	+4.7	+4.2	+4.1
Mean Low Water	MLW	+1.3	+1.3	+1.3
Mean Lower Low Water	MLLW	+0.0	+0.0	+0.0
Extreme Low Water	ELW	-	-	-3.0

3. **Protection from High Seas**. The entrance to Coos Bay is similar to most harbors along the Pacific Coastline of Northern California, Oregon, and Washington. Strong winds are often experienced at North Bend on Coos Bay during the months of June, July, and August. These winds blow at 17 knots or greater 15-20 percent of the time and at 28 knots or greater 1 to 2 percent of the time. The harbor consists of a river estuary at the mouth of the Coos River. Sand and silt

from the river are carried out to the sea from this entrance. As a result of this material meeting the predominantly westerly seas and swells of the Pacific, a sandy ridge bar is formed at the mouth. This sand ridge causes the channel to be known as “a Bar Channel”. As such, a breaking bar does occur in this port.

4. **Natural Hazards**. The navigational hazards in the vicinity of the project site are rock jetties on either side of the channel entrance extending into the Pacific Ocean, and a submerged jetty which extends 50 yards off the east shore of Coos Bay. Discussions and simulations with the Coos Bay Pilots Association have shown that these hazards will not interfere with normal navigation and mooring operations and the applicant has developed transit mitigations to address this issue such as not bringing vessels in or leaving them at the lay berth during conditions that are not conducive to safe navigation i.e. restricted visibility, severe weather and and/or low tides.

5. **Fishing Vessels**. Heavy concentrations of fishing gear may be expected between December 1 and August 15, from shore to about 30 fathoms.

6. **Underwater Pipelines and Cables**. Based on current pipeline charts that are available, there are three cables which are submerged approximately 20 feet running across/underneath the channel in the vicinity of the town of Empire which is on the LNG Carrier transit route.

7. **Maximum Vessel Size by Dock**. The primary dock can accommodate a vessel with a maximum length of 300 meters, 52 meters in breadth, and a draft which can be accommodated by the existing channel. Although the facility dock is able to accommodate vessels drafting up to 12m (39ft), current channel draft is 11m (37ft) with future plans to dredge the channel to accommodate larger deep draft vessels. Jordan Cove Energy Project and the local pilots must ensure transiting LNG vessels are able to maintain 10% under keel clearance as required by JCEP's LNG Transit Management Plan.

    a. The dock must be able to accommodate all vessels calling on the facility.
    b. It must be equipped with adequate numbers of mooring hooks, fendering, and mooring dolphins.
    c. The mooring arrangement must also be able to accommodate safe working loads.
    d. In coordination with appropriate stakeholders, JCLNG must develop and implement vessel mooring/unmooring procedures to ensure safe and environmentally protective operations for LNG Carriers arriving and departing the JCLNG facility.

8. **Vessel Routing**. Included in the WSA, was a plan to divide the LNG Carrier transit route into five (5) inbound, one (1) loading at berth, and five (5) outbound segments. The total inbound transit from the Sea Buoy (pilot boarding area) to the terminal berth is approximately eight (8) miles and will take between 1.5 and 2.0

hours to berth, pilots will be transiting at around 4.5 knots. The route has been divided into segments in order to manage vessel traffic and increase the safety of LNG carrier transits. This was done in conjunction with the Coos Bay Pilots Association.

The route is reversed for outbound LNG Carrier transits with the exception of the turning/maneuvering basin which is bypassed on the outbound transit where the LNG Carrier is moved directly into the Coos Bay Ship Channel. The route and segments are shown in Figure 3.

Figure 3. Overview of LNG Carrier Transit Route

9. **Vessel Operations –**LNG vessels will load cargo at the facility. 110-120 arrivals are expected at the facility annually with a dedicated fleet of LNG Carriers conducting cargo operations at the facility. A lay berth will be constructed to accommodate delays, repairs, and maintenance issues associated with Trans-Pacific Trade. Cargo operations will not be permitted at the lay berth and the applicant will outline procedures for the lay berth after the permitting process is complete.

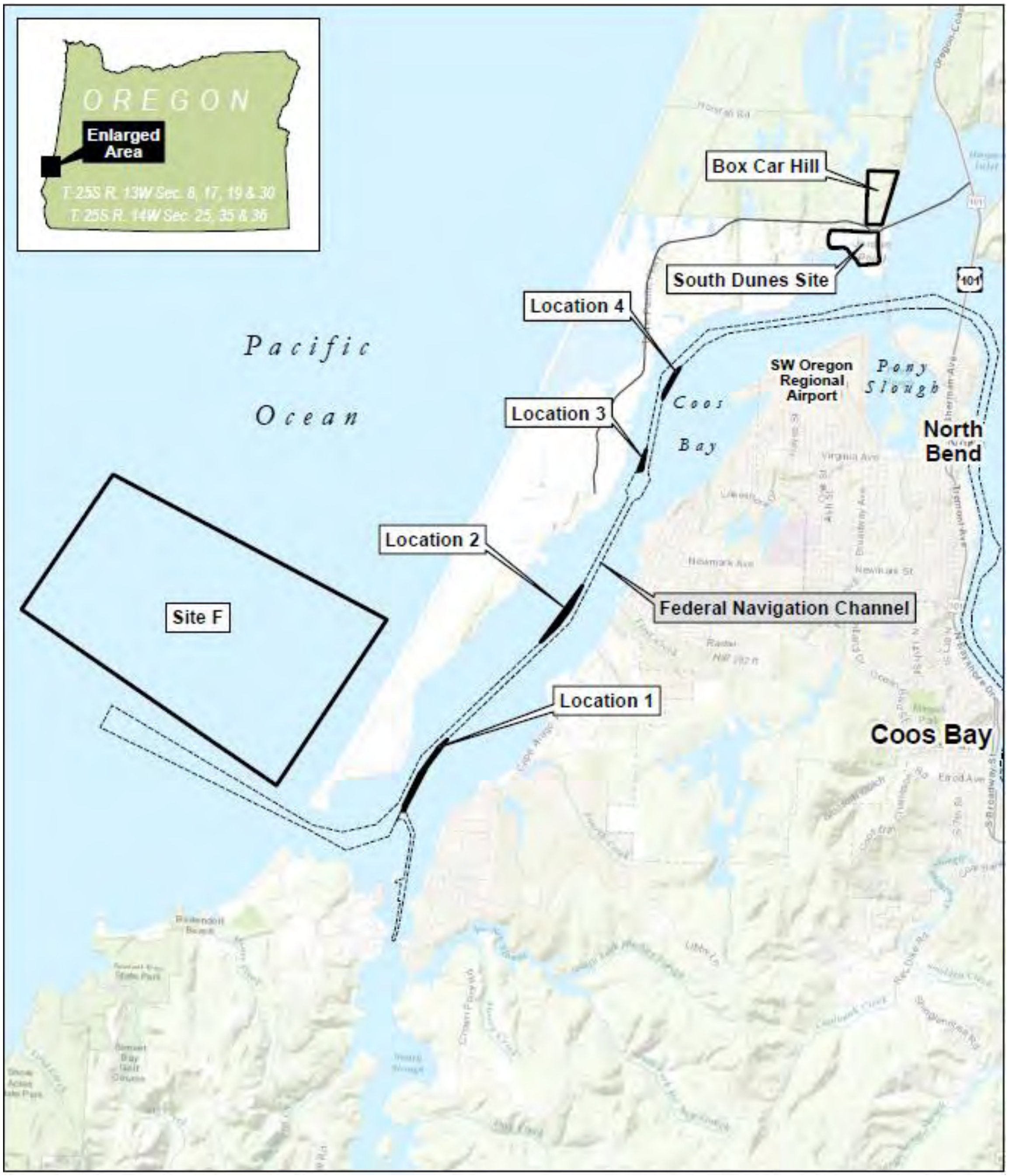

Figure 4. Channel Improvements

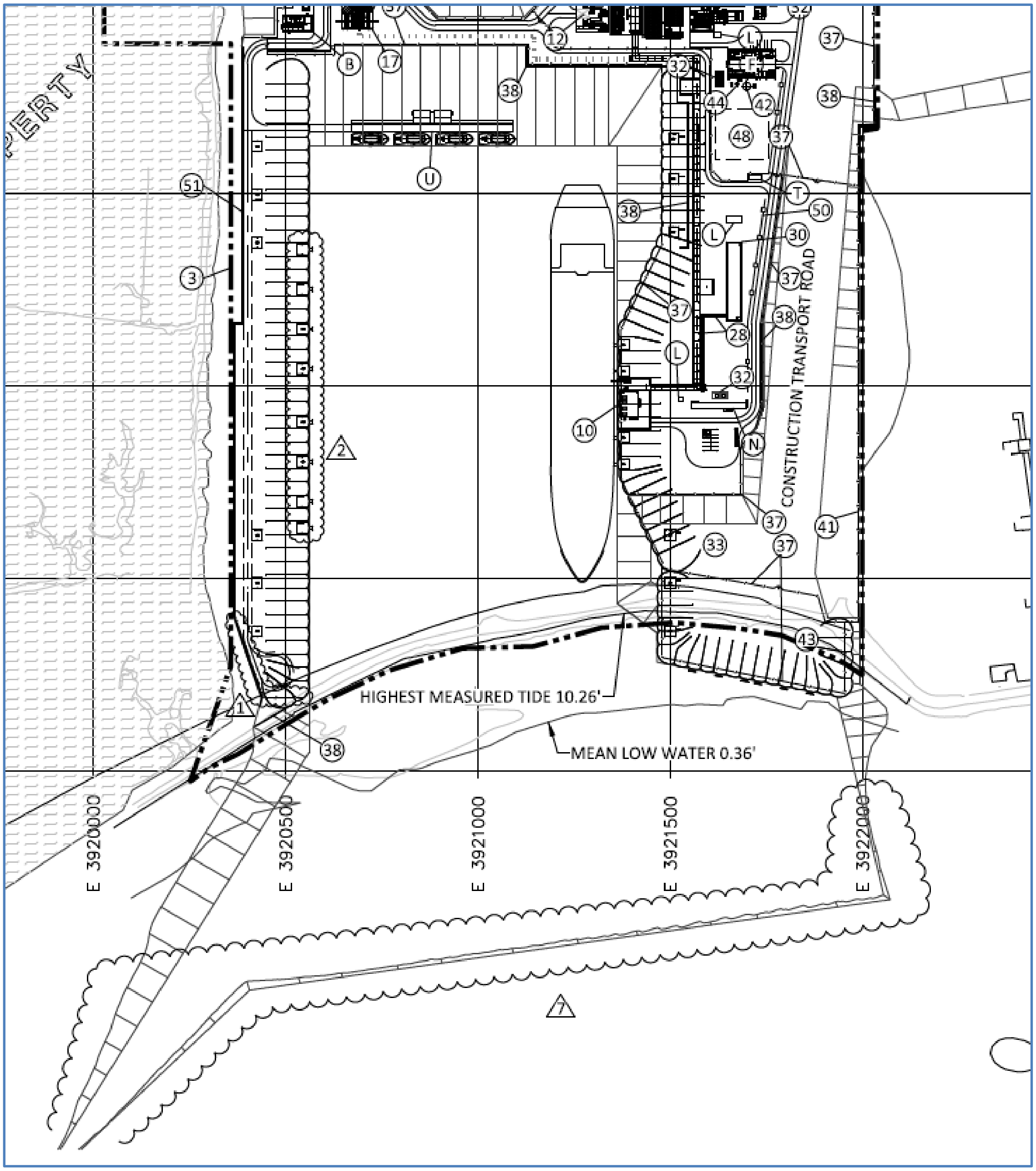

Figure 5. Dredging at the berth

U.S. Department of Homeland Security
United States Coast Guard

Commander
United States Coast Guard
Sector Portland

6767 N. Basin Avenue
Portland, Oregon 97217-3992
Phone: (503) 240-9374
Fax: (503) 240-9369
Russell.A.Berg@uscg.mil

16611/JORDAN COVE
April 24, 2009

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

LETTER OF RECOMMENDATION FOR JORDAN COVE LNG TERMINAL

Dear Ms. Bose:

This Letter of Recommendation (LOR) is issued pursuant to 33 C.F.R. § 127.009 in response to the Letter of Intent (LOI) submitted by Jordan Cove Energy Project, L.P. (Applicant) dated April 10, 2006 proposing to transport Liquefied Natural Gas (LNG) by ship to a proposed receiving terminal at Jordan Cove in Coos Bay, Oregon. It conveys the Coast Guard's determination on the suitability of Coos Bay for LNG marine traffic as it relates to safety and maritime security. In addition to meeting the requirements of 33 C.F.R. § 127.009, this letter also fulfills the Coast Guard's commitment for providing information to your agency under the Interagency Agreement signed in February 2004.

After reviewing the information in the applicant's LOI and completing an evaluation of the waterway in consultation with a variety of local port stakeholders, I have determined that the applicable portions of Coos Bay and its approaches are not currently suitable, but could be made suitable for the type and frequency of marine traffic associated with this project. My determination is based on review of the information provided in accordance with 33 C.F.R. § 127.007(d)(3) through (d)(6) and in consideration of the items listed in 33 C.F.R. § 127.009(b) through (d)(6). The reasons leading to my determination are outlined below.

On July, 1, 2008, I completed a review of the Applicant's Waterway Suitability Assessment (WSA) submitted in February 2007 by Kseas and Amergent Techs. This review was conducted following the guidance provided in U.S. Coast Guard Navigation and Vessel Inspection Circular (NVIC) 05-05. The review focused on navigation safety and maritime security risks posed by LNG marine traffic associated with the proposed Jordan Cove Energy Project and the measures needed to responsibly manage these risks. During the review, the Coast Guard consulted with a variety of stakeholders including an adhoc validation committee and the Area Maritime Security Committee. Following this review a Waterway Suitability Report (WSR) was issued in July 2008. The WSR identifies the requirements, conditions and risk mitigation measures to ensure the safe movement of these vessels.

The Applicant's WSA includes risk management strategies and associated measures that were developed for the safe navigation and security at each maritime security level, and that if properly implemented, sufficiently mitigate the identified risks associated with LNG vessel traffic for the proposed facility. These risk mitigation measures and strategies have been documented in the attached WSR. Based on my review and the full implementation by the Applicant of the measures outlined in their WSA and the attached WSR, I have determined that

Coos Bay leading up to Jordan Cove could be suitable for the type and frequency of LNG marine traffic associated with this project.

The final review and this letter are issued pursuant to NVIC 05-08, which replaced NVIC 05-05. NVIC 05-08 eliminated the term WSR and replaced it with "Letter of Recommendation (LOR) Analysis". For the purpose of clarity, the WSR is equivalent to the LOR Analysis. While this letter has no enforcement status, the determinations, analysis, and ultimate recommendation as to the suitability of this waterway as contained in this letter, would be referenced in concert with a Captain of the Port Order, should an LNG transit be attempted along this waterway without full implementation of the risk mitigation measures. Such an Order would be issued pursuant to my authority under the Ports and Waterways Safety Act of 1972, as amended by the Port and Tanker Safety Act of 1978, 33 U.S.C. § 1223, *et seq.*, among other authorities.

A copy of the LOR has been forwarded to the Applicant. Should the Applicant feel aggrieved by this decision, they may request reconsideration by me pursuant to 33 C.F.R. § 127.015(a). For your information, any request for reconsideration must be submitted in writing, within 30 days of receipt of this letter. The Applicant may also request an in person appeal if the written request would have an adverse impact on their operation.

If you have any questions, my point of contact is Mr. Russ Berg. He can be reached at the above address, phone number and e-mail.

Sincerely,

F. G. MYER
Captain, U. S. Coast Guard
Captain of the Port

Enclosures: (1) WSR
(2) WSR Supplementary Record (SSI, Not Releasable)

Copy: Jordan Cove Energy Project, L.P. w/o enclosures
Commandant, U. S. Coast Guard (CG-522, CG-541, CG-544) w/o enclosures
Commander, Thirteenth Coast Guard District (dl, dp) w/o enclosures
Commander, Coast Guard Pacific Area (Pp) w/o enclosures
Coast Guard Maintenance and Logistics Command Pacific (sm) w/o enclosures
Oregon Department of Energy w/o enclosures
Oregon Department of Fish and Wildlife w/o enclosures
Coos County Sheriff w/o enclosures
Coos Bay Fire Department w/o enclosures
Coos Bay Police Department w/o enclosures
North Bend Fire Department w/o enclosures
North Bend Police Department w/o enclosures

APPENDIX B

Jordan Cove's Letter of Intent and the U.S. Coast Guard's Waterway Suitability Report for the Jordan Cove Energy Project

ENCLOSURE(3)

Jordan Cove Energy Project, L.P.

April 10, 2006

Captain Patrick Gerrity
Commanding Officer
USCG Sector Portland
6767 N. Basin Ave.
Portland, Oregon 97217

RE: **Jordan Cove Energy Project**
Coos Bay, Oregon
Letter of Intent

Dear Captain Gerrity:

Under the requirements of 33 CFR 127.007, I am pleased to forward this LETTER OF INTENT (LOI) for the construction of an LNG receiving terminal located at Coos Bay, Oregon. As part of this proposal, I am attaching as Enclosure (1) a Preliminary Waterway Suitability Assessment (WSA), which has been completed using the guidance contained in Enclosure (2) of Navigation and Vessel Circular No. 05-05, (NVIC 05-05) dated June 14, 2005.

This Preliminary WSA has been prepared to meet the requirement to start the "Pre-Filing" process with the Federal Energy Regulatory Commission (FERC). It is understood that a "Follow-on" WSA will be required to be submitted to you as this project matures. The "Follow-on" WSA will clearly identify credible security threats and safety hazards to LNG transportation in this port, and will identify appropriate risk management measures, as well as addressing items of concern noted in the Preliminary WSA.

In accordance with the requirements contained in 33 CFR 127.007 (d), the following information is provided:

1. The name, address, and telephone number of the owner and operator:

Jordan Cove Energy Project
125 Central Avenue, Suite 380
Coos Bay, OR 97420
Attn: Robert L. Braddock
Phone: (541) 266-7510
Fax: (541) 269-1475
E-mail: bobbraddock@attglobal.net

The name, address and telephone number of the facility: (since the facility has not been constructed, the information is the same as in item 1 above.

Jordan Cove Energy Project
125 Central Avenue, Suite 380
Coos Bay, OR 97420
Attn: Robert L. Braddock
Phone: (541) 266-7510
Fax: (541) 269-1475
E-mail: bobbraddock@attglobal.net

2. Physical location of the facility: *This information is contained in Section 3.10 of the Preliminary WSA included as Enclosure (1) to this report.*

3. Description of the facility: *This information is contained in Section 3.10 of the Preliminary WSA included as Enclosure (1) to this report.*

4. LNG vessel characteristics and frequency of shipments to and from the facility: *This information is contained in Section 3.11 of the Preliminary WSA included as Enclosure (1) to this report.*

5. Charts showing waterway channels and identifying commercial, industrial, environmentally sensitive and residential areas in and adjacent to the waterway used by the LNG vessel en route to the facility, within 15.5 miles of the facility. *This information is contained in Sections 2.5, 3.1, 3.13, 3.14, 3.15 and 3.16 of the Preliminary WSA included as Enclosure (1) to this report.*

We understand the requirement to advise you in writing within 15 days if there are any changes to the information presented in this letter in paragraphs 1 – 5 above. We do not anticipate any construction starting in the next 60 days or LNG transfer operations in the next 12 months.

I trust the information provided meets all LETTER OF INTENT requirements. Please feel free to contact me at any time to discuss this proposal, or if you require any further documentation incident to this submission.

Sincerely,

Robert L. Braddock

Robert L. Braddock
Project Manager

ENCL: (1) Preliminary Waterway Suitability Assessment

U.S. Department of Homeland Security
United States Coast Guard

Commanding Officer
United States Coast Guard
Sector Portland

6767 N. Basin Avenue
Portland, OR 97217
Phone: (503) 240-9307
Fax: (503) 240-9586

16611
July 1, 2008

Lauren O'Donnell
Director of Gas – Environmental & Engineering, PJ-11
Federal Energy Regulatory Commission
888 First Street, N.E., Room 62-45
Washington, DC 20426

WATERWAY SUITABILITY REPORT FOR THE JORDAN COVE ENERGY PROJECT

Dear Ms. O'Donnell:

This Waterway Suitability Report (WSR) fulfills the Coast Guard's commitment under the Interagency Agreement among the Federal Energy Regulatory Commission (FERC), the Research and Special Programs Administration (RSPA), and the Coast Guard for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities that was signed in February 2004. Under this agreement, our agencies work together to ensure that both land and maritime safety and security risks are addressed in a coordinated and comprehensive manner. In particular, the Coast Guard serves as a subject matter expert on maritime safety and security issues.

On June 11, 2008, the Coast Guard completed a review of the Waterway Suitability Assessment (WSA) for the Jordan Cove Energy Project (JCEP) that was submitted in September of 2007. This review was conducted following the guidance provided in Navigation and Vessel Inspection Circular (NVIC) 05-05 of June 14, 2005. The review focused on the navigation safety and maritime security risks posed by LNG marine traffic, and the measures needed to responsibly manage these risks. During the review, the Coast Guard consulted a variety of stakeholders including state and local emergency responders, marine pilots, towing industry representatives, members of the Ports and Waterways Safety Committee and the Area Maritime Security Committee.

Based upon this review, I have determined that Coos Bay is not currently suitable, but could be made suitable for the type and frequency of LNG marine traffic associated with this proposed project. Additional measures are necessary to responsibly manage the maritime safety and security risks. The specific measures, and the resources needed to implement them, where applicable, are described below and in a separate supplementary report which is being provided to you under the terms and conditions established for handling Sensitive Security Information (SSI). This supplemental report includes a copy of the Jordan Cove Waterway Suitability Assessment. This determination is preliminary as the NEPA analysis has not yet been completed.

The following is a list of specific risk mitigation measures that must be put into place to responsibly manage the safety and security risks of this project. Details of each measure, including adequate support infrastructure, will need further development in consultation with the Coast Guard and state and local agencies through the creation of an Emergency Response Plan as well as a Transit Management Plan that clearly spell out the roles, responsibilities, and specific procedures for the LNG vessel and all agencies responsible for security and safety during the operation.

Navigational Measures:

LNG Tanker Size Limitations: Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, the maximum size LNG tanker permitted to transit through the Port of Coos Bay is a spherical containment LNG carrier with the physical dimensions of a 148,000 m^3 class vessel. The ship dimensions used in the study reflect a length overall of 950 feet, beam of 150 feet and a loaded draft of 40 feet. The channel must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed. Consequently, prior to approving the transit of an LNG ship larger than 148,000 m^3, or any increase in the physical dimensions cited, additional simulator studies must be conducted in order to assure the sufficiency of the channel.

- Safety/Security Zone: A moving safety/security zone shall be established around the LNG vessel extending 500-yards around the vessel but ending at the shoreline. No vessel may enter the safety/security zone without first obtaining permission from the Coast Guard Captain of the Port (COTP). The expectation is that the COTP's Representative will work with the Pilots and patrol assets to control traffic, and will allow vessels to transit the Safety/Security zone based on a case-by-case assessment conducted on scene. Escort resources will be used to contact and control vessel movements such that the LNG Carrier is protected.

  While the vessel is moored at the facility there shall be a 150 yard security zone around the vessel, to include the entire terminal slip. In addition, while there is no LNG vessel moored, the security zone shall cover the entire terminal slip and extend 25-yards into the waterway.

  Resource Gap: Resources required to enforce the safety/security zone are discussed under Security Measures in the supplemental report.

- Vessel Traffic Management: Due to a narrow shipping channel, navigational hazards, and the proximity to populated areas, LNG vessels will be required to meet the following additional traffic management measures:
  - A Transit Management Plan must be developed in coordination with the Coos Bay Pilot Association, Escort Tug Operators, Security Assets and the Coast Guard prior to the first transit.
  - This plan must be submitted to the COTP no less than 6 months to initial vessel arrival, and followed by an annual review to ensure that it reflects the most current conditions and procedures.
  - For at least the first six months, all transits will be daylight only, unless approved in advance by the COTP.
  - The LNG Vessel must board Pilots at least 5 miles outside the sea buoy.
    - Overtaking or crossing the LNG tanker within the security zone is prohibited for the entire transit from the Coos Bay Sea Buoy to mooring the vessel at the LNG terminal.
  - Vessel transits and bar crossings will be coordinated so as to minimize conflicts with other deep draft vessels, recreational boaters, seasonal fisheries, and other Marine Events.
  - 24 hours prior to arrival, the Coast Guard, FBI, Coos Bay Pilot Association, Escort Tug Masters, and other Escort assets will meet to coordinate inbound and outbound transit details.

Resource Gaps: The Vessel Transit Management Plan must be approved by the COTP at least 60 days prior to the first vessel arrival.

- Vessel Traffic Information System /Vessel Traffic System: The Port of Coos Bay does not have the capacity to receive Automatic Identification System (AIS) signals. AIS receiving capability must be established and must have the capacity to be used by appropriate agencies, port authorities and ship husbandry companies. Additionally, the Port does not have any means for continuous monitoring the navigable waterway. In order to ensure vessel safety and security, a robust camera system capable of monitoring the entire transit route must be established. Due to weather concerns, these cameras must be equipped with the means to adequately monitor vessel traffic in wind, rain and fog conditions.

  Resource Gaps: AIS receiver and camera systems including necessary hardware, software, staffing and training. Camera system must have complete coverage of the entire transit route, capable of detecting vessel traffic in wind, rain, fog, and dark conditions. Equipment and access to data feed of video imagery must be provided to state and local emergency operations centers impacted by the project.

- Tug Escort and Docking Assist: Due to the confined channel and high wind conditions, each LNG Carrier must be escorted by two tractor tugs, which will join the vessel as soon as safe to do so. The primary tug will be tethered at the direction of the pilot. A third tractor tug is required to assist with turning and mooring. Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, vessels are limited to transiting during periods of high tide and 25 knot winds or less. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.

  All three tractor tugs must be at least 80 Ton Astern Bollard Pull or larger and equipped with Class 1 Fire Fighting equipment.

  Resource Gaps: Three 80 Bollard Ton Tractor Tugs with Class 1 Fire Fighting capability.

- Navigational Aids:
  - Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, four aids to navigation must be added and eight aids to navigation relocated on the waterway (pg. 12-17).
  - Physical Oceanographic Real-Time System (PORTS) must be contracted with NOAA to provide real time river level, current and weather data.

- LNG Carrier familiarization training for Pilots and Tug Operators: Prior to the arrival of the first vessel, simulator training must be provided for pilots and tug operators identified as having responsibility for LNG traffic.

Safety Measures:

Emergency Response Planning: Regional emergency response planning is limited in the region. Emergency response planning resources will need to be augmented to adequately develop emergency response procedures and protocols as well as continuously update those plans as conditions change.

Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Vessel and Facility Inspections: LNG tankers and facilities are subject to (at a minimum) annual Coast Guard inspections to ensure compliance with federal and international safety, security and pollution regulations. In addition, LNG vessels and facilities are typically required to undergo a pre-arrival inspection, and transfer monitor.

  Resource Gap: Additional Coast Guard Facility and Vessel Inspectors.

- Shore-Side Fire-Fighting: Firefighting capability is limited in the area surrounding the proposed LNG terminal. Shore side firefighting resources and training will need to be augmented in order to provide basic protection services to the facility as well as the surrounding communities along the transit route.

  Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- In-Transit Fire-Fighting: Firefighting capability is limited along the entire transit route for proposed LNG vessels.

  Resource Gap: A plan must be developed for managing underway firefighting, including provisions for command and control of tactical fire fighting decisions as well as financial arrangements for provision of mutual aid and identification of suitable locations for conducting fire fighting operations along the transit route. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

  Public Notification System and Procedures: Adequate means to notify the public along the transit route, including ongoing public education campaigns, emergency notification systems, and adequate drills and training are required. Education programs must be tailored to meet the various needs of all waterway users, including commercial and recreational boaters, local businesses, local residents, and tourists.

  Resource Gap: A comprehensive notification system, including the deployment of associate equipment and training, must be developed. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Gas Detection Capability: No gas detection capability exists at the Port of Coos Bay, along the transit route and at the site of the proposed facility. Emergency response personnel require appropriate gas detection equipment, maintenance, and training. Additionally, the use of fixed detection equipment will ensure accurate and expedited gas detection in the event of a large scale LNG release. The installation of these detectors at strategic points along the waterway must be developed.

Resource Gap: Gas Detectors, appropriate training, and maintenance infrastructure. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

[redacted]

- [redacted]
- [redacted]
- [redacted]

In the absence of the measures described in this letter and the resources necessary to implement them or changes in Coast Guard policy upon which the resource decisions are based, Coos Bay would be considered unsuitable for the LNG marine traffic associated with the Jordan Cove LNG Terminal. The applicant shall be required to submit an annual update to the Waterway Suitability Assessment to the Coast Guard which shall be revalidated by the COTP and AMSC. For further information, please contact Mr. Russ Berg of Coast Guard Sector Portland at (503) 240-9374.

Sincerely,

F. G. Myer
Captain, U.S. Coast Guard
Captain of the Port
Federal Maritime Security Coordinator

Copy: Thirteenth Coast Guard District (dp)
Coast Guard Pacific Area (Pp)
Commandant, Coast Guard Headquarter (CG-52), (CG-522), (CG-544)
Maintenance and Logistics Command Pacific (Sm)

Exhibit 3

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
September 7, 2019

Re:
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000
Response to August 28, 2019 PHMSA Data Request

My comments are not to be attributed to the University of Arkansas.

This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016; September 22, 2018; October 2, 2018; December 3, 2018; April 1, 2019; July 18, 2019; and August 27, 2019 - all of which I stand by.

On August 28, 2019, the U.S. Department of Transportation, Pipeline and Hazardous materials Safety Administration (PHMSA) Staff issued questions and information requests related to PHMSA's review of the siting requirements under 49 CFR Part 193,Part B ("August 28 PHMSA Request").

These comments address only JCEP's response to Scenarios MR-2 involving the use of FLACS-Fire. However, these comments are not directed to the details of the calculations (using FLACS-Fire) presented for Scenario MR-2. My purpose here is to emphasize the same concerns raised in my previous (August 27, 2019) comments, and to expand on the importance of PHMSA taking immediate corrective action.

I believe that the use of FLACS-Fire in JCEP's submission effectively circumvents the intent of 49 CFR Part 193, Part B because it has not been approved by PHMSA for such use. If I am wrong about this, I respectfully ask that PHMSA immediately notify me, and I will take the necessary corrective action.

If I am not wrong about this, I believe we are, as a result of this action, further enabling the applicant to circumvent the Regulations in a manner that will result in important decreases in the provision of Public Safety.

The current LNG regulations focus on providing public safety by requiring that the applicant provide approved science-based calculations of exclusion distances to prevent public injury beyond the plant boundaries from liquid pool fires and vapor cloud fires and explosions.

The FLACS model, which is increasingly used in applications for LNG Export Terminal Siting applications, is a complex suite of mathematical modeling methods that are advertised to address the calculation of Dispersion, Fire Radiation, and Vapor Cloud Explosion hazards.

The FLACS Model used by JCEP designed to predict dispersion has received PHMSA approval for use in applications to meet the requirements of 49 CFR 193.

The FLACS Model used by JCEP designed to predict vapor cloud explosion overpressures has not received such approval.

It is my understanding that the FLACS-Fire Model used by JCEP in the application here considered to calculate fire radiation intensity to ensure that the prescribed radiation limits do not extend beyond the property values has not received such approval.

If I am correct in the assumptions I have made here, I believe there has been a critically important failure to provide for Public Safety in the current regulations designed for siting LNG Export Terminals. The current regulations were designed for LNG Import Terminals. It is established knowledge that Export Terminals involve important hazards that are not present in Import Terminals. There has been a failure to update the Regulations accordingly. I am very concerned that the current moves to provide "Regulatory Relief While Preserving Public Safety" are going badly wrong. In my opinion, just as in the current debate about the science information about Global Warming/Climate Change, the debate about the push to expand the LNG Export business in the United States is allowing the Export Terminal applicants-for-siting to cut regulatory corners by adopting complex mathematical models that are used to determine the risks involved without proper science-based evaluation.

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
August 27, 2019

Re:
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000
Part 193, Subpart B Siting Review Supplement

My comments are not to be attributed to the University of Arkansas.

This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, December 3, 2018, April 1, 2019 and July 18, 2019 - all of which I stand by.

On August 14, 2019, the U.S. Department of Transportation, Pipeline and Hazardous materials Safety Administration (PHMSA) Staff issued questions and information requests related to PHMSA's review of the siting requirements under 49 CFR Part 193,Part B. These comments address only the first Information Request (Request 1):

> *In response to Request 2 from the PHMSA Information Request dated August 2, 2019, the analysis considered the 2-dimensional Phast output results from a jet fire occurring from release scenario LNG-17 that indicated at a flame height of 96.23 feet, the impacts from a jet fire do not extend over the 100-foot wall. Furthermore, the Phast output summary file provided for scenario LNG-17 indicates the length of the flame is 584 feet, which appears to be greater than the distance between the release location and the 100-foot wall. This means the tip of the flame as well as its thermal radiation may spread vertically along the height of the wall. Since the 2-dimensional analysis does not account for this spreading of the flame, the height not extending over the 100 foot wall is not indicative of the exclusion zone remaining onsite.*
>
> *In addition, it remains unclear whether the radiant heat from a jet fire from MR-2 will remain onsite.*
>
> *Provide an analysis that demonstrates the 1600 Btu/hr-ft^2 from jet fire scenarios LNG-17 and MR-2 would remain within the property legally controlled by Jordan Cove using a modeling software that accounts for the obstruction from plant equipment and the 100-foot wall.* *(emphasis added)*

JCEP provided two figures with accompanying text from which they appear to conclude that the 1600 Btu/hr-ft^2 (thermal radiation level?) from jet fire scenarios LNG-17 and MR-2 would remain within the property legally controlled by Jordan Cove. JCEP's response stated that these two scenarios were modelled using FLACS-Fire version 10.9.

It is my understanding that the currently applicable version of CFR193.2057, Thermal radiation protection, requires that thermal radiation distances must be calculated using Gas Technology Institute's (GTI) report or computer model GTI-04/0032 LNGFIRE3: A Thermal Radiation Model for LNG Fires (incorporated by reference, see 193.2013). The use of other alternate models which take into account the same physical physical factors and have been validated by experimental test data may be permitted subject to the Administrator's approval.

I am here respectfully requesting an answer to the following questions:

1. Has a request from, or on behalf of, JCEP been received by PHMSA for approval of the alternate (to LNGFIRE3) FLACS-Fire Version 10.9 model?
2. If such a request has been received, please provide a statement of PHMSA's response to the request.

From my position of working specifically on these matters of the calculations submitted by JCEP to obtain approval for the siting of the LNG export terminal in Coos Bay, Oregon since early 2015, and my four decades experience with PHMSA and other governmental regulators in trying to ensure that the regulations in force utilize good, carefully vetted, scientific tools to protect public safety, I am saddened to feel that the safety regulation process is being circumvented.

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
July 18, 2019

Regarding the

DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT

Docket Nos. CP17-494-000 and CP17-495-000
of March 2019

My comments are not to be attributed to the University of Arkansas.

COMPUTER MODEL USED TO PREDICT LNG EXPORT TERMINAL VAPOR CLOUD EXPLOSION HAZARDS HAS NOT BEEN APPROVED BY PHMSA – THERE IS NEW PUBLISHED INFORMATION CONCERNING THE UNCERTAINTY IN THE FLACS EXPLOSION CALCULATIONS

This comment is intended to notify PHMSA of new developments regarding our knowledge of the risk of cascading fire and unconfined vapor cloud explosion (UVCE) accidents that could occur at the Jordan Cove Export Terminal (JCET). This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, December 3, 2018, and April 1, 2019 - all of which I stand by.

As stated in my previous comments, my review of the March 2019 JCET DEIS did not disclose any detailed predictions of vapor cloud explosion (VCE) overpressure for design spills of heavy hydrocarbons, but I did locate on the FERC Website a report entitled "Facility Siting Hazard Analysis", dated October 2, 2018, which presents a collection of hazard footprints for overpressure, calculated with FLACS, predicted to result from design spills of heavier-than-methane hydrocarbons at the JCET[1]. The overpressures presented therein still appear to be significantly lower than those reported for numerous incidents that have occurred with the same materials, in similar amounts and in similar conditions. I am very concerned that such predictions might be approved by FERC in the FEIS - repeating the approval of similar predictions prepared for FERC with the same mathematical model FLACS in 2015.

Although a process for developing a written protocol for evaluation of FLACS for application to the prediction of overpressures was requested by PHMSA to be funded following the LNG Regulation Workshop of 2016[2], it appears that the plans announced at the LNG Workshop of 2016 for a required updating of 49 CFR 193 to cater for the new hazards that will be present at export terminals are at a standstill.

---

[1] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198
Click on "Facility Siting Hazard Analysis" and download

[2] https://primis.phmsa.dot.gov/rd/mtgs/111616/WG%205%20Report-Out.pdf – See GAP #4

Sub-Model Q9

It is my understanding that the sub-model named Q9 was used in FLACS to compute the explosion overpressure predictions in the Jordan Cove DEIS. I believe those predictions may well be an order-of- magnitude too low. As the FLACS model has yet to be evaluated by subjection to a written Protocol, as currently required by PHMSA, it follows that the sub-model Q9 has not been evaluated either.

The purpose of this comment is to request that PHMSA consider a scientific review paper regarding Q9 recently published by the British Health and Safety Executive[3]. I believe this paper substantiates my concerns that there are such large uncertainties in the Q9 method, as utilized currently in FLACS, as to result in order of magnitude (too low) errors in overpressures. Such errors could result in the dismissal of the UVCE hazard for heavy hydrocarbon gas clouds considered as "Design Spills" in the recent Jordan Cove DEIS. I am very concerned that correction of these errors has the potential to change the overpressures presented in the Jordan Cove DEIS to indicate overpressures an order of magnitude higher, which would bring those predictions into substantial agreement with the extensive historical review by the British Health and Safety Laboratories presented at the LNG Regulatory Workshop in 2016. Such overpressures could well lead to destruction of the plant and extend danger to the public outside the controlled boundary.

[3] Stewart, J., Gant, S. and Bilio M. (2019) "A review of the Q9 Equivalent cloud method for explosion modelling", Fire and Blast Information Group (FABIG) Technical Newsletter 75, March 2019. Available from: http://www.fabig.com/video-publications/TechnicalNewsletters

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
April 1, 2019

Regarding the
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT
Docket Nos. CP17-494-000 and CP17-495-000
March 2019

My comments, directed simultaneously to FERC and PHMSA,
are not to be attributed to the University of Arkansas.

COMPUTER MODEL USED TO PREDICT LNG EXPORT TERMINAL VAPOR CLOUD EXPLOSION HAZARDS HAS NOT BEEN APPROVED BY PHMSA - PREDICTED EXPLOSION OVERPRESSURES APPEAR SERIOUSLY UNDERESTIMATED

These comments are intended to notify FERC, PHMSA, and the public of critically important developments regarding our expanding knowledge of the risk of cascading fire and unconfined vapor cloud explosion (UVCE) accidents that could occur at the Jordan Cove Export Terminal (JCET). The comments are an expansion on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, and December 3, 2018 - all of which I stand by. They are also intended as a response to the joint news release of August 31, 2018 by PHMSA and FERC, entitled " FERC, PHMSA Sign MOU to Coordinate LNG Reviews**"**, from which I quote - "The MOU establishes a framework **for** coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public impacts". I trust these comments will be helpful to the decision-makers in fully informing the public.

My concerns remain essentially the same as commented to FERC in January 2015 by James Venart and myself[1]. I believe that Government is failing to adequately provide for the risks of potentially devastating Unconfined Vapor Cloud Explosions (UVCEs) of heavier-than-methane hydrocarbons at the JCET.

I remain concerned that the predictions of explosion overpressures (determining explosion damage) presented in the 2015 JCET DEIS were an order of magnitude (factor 10) too low. Such overpressures are not conservative enough to indicate the real hazard that exists, as evidenced by numerous confirmed occurrences of devastating UVCEs involving the same heavy hydrocarbons in similar conditions.

My review of the March 2019 JCET DEIS did not disclose any detailed predictions of vapor cloud explosion (VCE) overpressure for design spills of heavy hydrocarbons. However, I did locate on the FERC Website a report entitled "Facility Siting Hazard Analysis", dated October 2, 2018, which

[1] UNITED STATES LNG TERMINAL SAFE-SITING POLICY IS FAULTY, Comments submitted to FERC by Jerry Havens and James Venart, January 14, 2015, Docket No. CP13-483.

presents a collection of hazard footprints for overpressure, calculated with FLACS, predicted to result from design spills of heavier-than-methane hydrocarbons at the JCET[2]. The collection of calculations presented in that report presents a picture very similar to that presented in the 2015 DEIS. The overpressures presented therein still appear to be significantly lower than those reported for numerous incidents that have occurred with the same materials, in similar amounts and in similar conditions. I cannot determine to what extent these newer predictions have been utilized in the 2019 DEIS, but I am very concerned that such predictions as these might be approved by FERC in the FEIS - repeating the approval of similar predictions prepared for FERC with the same mathematical model (FLACS) in 2015. If that were to happen, I believe a serious error affecting public safety will be the result, because the unrealistically low damage predictions could be used again by FERC as a basis to dismiss the UVCE hazard at the JCET. Continued dismissal of the UVCE hazard would be a very serious error. If the magnitude of the possible overpressures are estimated using actual data (experience) available for UVCEs (rather than predicted with the FLACS theoretical model), the VCE hazard would be clearly indicated as a serious major hazard at the JCET[3]. *UVCEs at numerous similar heavy hydrocarbon handling/storage facilities have resulted in destruction of the facilities as well as injuries and deaths beyond the plant boundaries.*

Contrasting LNG Import and Export Terminal Siting Regulations

I want to state here that if either PHMSA or FERC believes that anything I present is in error I request that I be notified immediately. I will make any corrections as necessary, and I will alter my comments, as necessary, as well. My goal is to ensure that the science-based tools that are used for hazard evaluation in the regulations are applied correctly. I am very concerned that failure to ensure proper, validated, use of mathematical models for UVCE hazard evaluation could result in devastating UVCEs that, in addition to public endangerment, could cripple the industry.

In order to most effectively explain my concerns, I think it helpful to provide a very brief history of the LNG regulations. The provisions of 49 CFR 193. Liquefied Natural Gas Facilities: Federal Safety Standards were developed by PHMSA to govern the siting of LNG peak shaving terminals and import terminals. It has been accepted practice to identify for these two types of terminals only two principal hazards; pool fire hazards and vapor dispersion hazards. A third hazard, Unconfined Vapor Cloud Explosion (UVCE), is generally considered negligible for Import Terminals. This policy is based on the generally accepted fact that import terminals handle and store primarily LNG with methane contents sufficiently high that the LNG can be assumed to be pure methane. Given the very low propensity for explosion of unconfined methane-air clouds, UVCEs at LNG import terminals have historically been neglected as a hazard. As a consequence the present Regulation, 49 CFR 193, does not mandate the consideration of UVCE hazards.

With the advent of LNG export terminals in the United States the requirements for safe siting of LNG terminals have changed importantly. That is because the export terminals typically remove and store large quantities of heavier-than-methane hydrocarbons from the incoming natural gas feed stream. Furthermore, the removal of those heavy hydrocarbons typically requires the use of

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[2] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198
Click on "Facility Siting Hazard Analysis" and download

[3] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111 Atkinson, G., Vapor Cloud Explosion (VCE) Historical Review, PHMSA Public Workshop on Liquefied Natural Gas (LNG) Regulations, Washington DC, 19 May 2016.

large quantities of refrigerant gases that are heavier-than-methane hydrocarbons. The storage and handling of large quantities of these heavier-than- air hydrocarbons results in a new primary hazard - vapor cloud explosions of the heavy hydrocarbon materials that could follow accidental release.

I have been involved in the development of 49 CFR 193 from its beginning in the early 1980s. My principal involvement has been as an author/evaluator of the DEGADIS model for use in predicting LNG vapor cloud dispersion. DEGADIS is approved by PHMSA for use in predicting the requirements for vapor cloud dispersion exclusion zones for LNG Import Terminals. During the last decade, and coincident with the advent of LNG Export Terminals in the United States, additional vapor dispersion models have been approved by PHMSA for use by LNG terminal companies seeking siting approval.

My comments here are restricted to the FLACS model. The FLACS model is an example of what is known as a computational fluid dynamics (CFD) model. I generally support the use of CFD models for vapor dispersion predictions because they are appropriate for dealing with complexities not catered for by simpler models such as DEGADIS. Accordingly, I supported the approval by PHMSA of the FEM3A model developed by the Lawrence Livermore National Laboratory (LLNL) and I supported the request for PHMSA approval of FLACS for vapor dispersion use. I do not object to FLACS' approval, which PHMSA granted, for vapor dispersion prediction.

FLACS has not been Evaluated or Approved by PHMSA for Explosion Prediction

This is the crux of the matter. There are now four mathematical models approved by PHMSA for vapor dispersion prediction, in order of the time approved; DEGADIS, FEM3A, FLACS, and PHAST. All four were required by PHMSA to be subjected to evaluation of their performance in demonstrating suitable agreement with experimental data available from a collection of field and wind tunnel tests of vapor dispersion.

FLACS (FLame ACceleration Simulator) is a commercial Computational Fluid Dynamics (CFD) software used extensively for atmospheric dispersion modeling and explosion modeling in the field of industrial safety and risk assessment[4]. FLACS has been subjected to the written protocol provided by PHMSA and approved by PHMSA for vapor dispersion predictions required by 49 CFR 193. PHMSA has not completed development of a written protocol for the evaluation of FLACS for explosion prediction. Consequently, FLACS has not been formally evaluated for explosion prediction and has not received approval for the evaluation of UVCE hazards (read explosion overpressures) by PHMSA.

Although it appears that a process for developing a written protocol for evaluation of FLACS for application to the prediction of overpressures was requested by PHMSA to be funded following the LNG Regulation Workshop of 2016[5], I can find no evidence that the required protocol has been completed. It appears that the plans announced at the LNG Workshop of 2016 for a required updating of 49 CFR 193 to cater for the new hazards that will be present at export terminals are currently at a standstill. The only conclusion I am able to reach is that the newly announced JCET DEIS appears to me likely to utilize predictions of explosion overpressures for the heavier-than-methane hydrocarbon design spills selected for analysis that have not been approved by PHMSA. Such a failure to adequately address the risk of UVCEs would mean that potential risks of cascading

[4] https://en.wikipedia.org/wiki/FLACS

[5] https://primis.phmsa.dot.gov/rd/mtgs/111616/WG%205%20Report-Out.pdf – See GAP #4

violent explosions that could destroy the plant as well as extend dangers to the public beyond the facility boundary are effectively being ignored.

PHMSA Contracted for Expert Evaluation of the Risk of Unconfined Vapor Cloud Explosions

Simultaneously with my comments to FERC in 2015 I notified PHMSA of my concerns. I have also filed a total of four comments (to date) on PHMSA's LNG Regulation Workshop site. Further, there have been a series of important developments subsequent to my 2015 comments to FERC, the results of which I think are critically important to consider now.

PHMSA contracted with the British Health and Safety Laboratories (HSL) to prepare the report "Review of Vapour Cloud Explosion Incidents"[6]. Quoting excerpts from the Executive Summary of that report:[7]

> **"T**his review of major vapor cloud incidents has been jointly commissioned by the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and the UK Health and Safety Executive (HSE). The primary objective was to improve understanding of vapor cloud development and explosion in order to examine the potential for these hazards to exist or develop at LNG export plants that store substantial quantities of these flammable gases for use in the liquefaction process or as a by-product from the liquefaction …
>
> This review has not found any historical records of LNG (methane) vapor cloud explosions in open areas with severity sufficient to cause secondary damage to tanks and pipes and consequently rapid escalation of an incident from a minor process leak to a major loss of inventory.
>
> On the other hand some LNG sites (especially export sites) also hold substantial amounts of refrigerant gases and blends containing ethane, propane, ethylene and iso-butane. Higher hydrocarbons may also be produced and stored on LNG export sites as by-products of gas condensation. There are numerous examples of Vapor Cloud Explosions (VCEs) in open areas involving these higher molecular weight materials and the storage and use of higher molecular weight hydrocarbons on LNG export sites which may, if not managed adequately, introduce an additional set of incident scenarios in which VCEs trigger rapid escalation of loss of containment. (emphasis added)
>
> This study involves a review of 24 major VCE incidents focusing on source terms, cloud development and explosion mechanics. The incidents studied are split between permanent fuel gas (C2-C4 (e.g. LPG) and volatile liquids C4-C6 (e.g. gasoline). The source terms for leaks of gases and liquids are different but once a stable current of cold heavy vapor forms, the subsequent development of LPG and gasoline clouds are similar…
>
> An important finding from the review is that a high proportion of vapor cloud incidents occurred in nil/low wind conditions. By the term "nil/low wind" we mean a wind that was so weak close to the ground that it only detrained (stripped away) a small proportion of the vapor accumulating around the source … Rather than being picked up and moved downwind, the vapor flow in this case was gravity driven; spreading out in all directions and or following any downward slopes around the source.
>
> In many of the cases examined, 50% (12/24), there is clear evidence from the well-documented transport of vapor in all directions and/or meteorological records that the

[6] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111

[7] HSL Report on PHMSA LNG Regulation Workshop site.

vapor cloud formed in nil/low wind conditions. In a further 21% (5/24), the pattern of vapor suggests nil/low wind conditions but there is insufficient data available to be sure … incidents in nil/low wind conditions apparently make up the majority of historical records of the most serious VCEs … In nil/low wind conditions the cloud continues to grow throughout the time that the tank takes to empty… The maximum area covered by the flammable cloud is typically several hundred times greater in nil/low winds condition than in light winds.

The implication of this type of analysis is that if the density of ignition sources is constant and quite low in the area around the tank the chances of ignition in nil/low wind conditions would be hundreds of times greater for a given release. This illustrates why nil/low wind conditions dominate records of major vapor cloud incidents even though the weather frequency is low. Losses of containment in nil/low wind conditions are also particularly dangerous because a highly homogeneous cloud can be formed that may spread by gravitational slumping (without significant dilution) for hundreds of meters… A very large cloud that is all close to the stoichiometric ratio increases the risk of flame acceleration to a high pressure regime capable of seriously damaging storage and process facilities, when compared with clouds that are entraining air because of wind-driven dilution. This is because fundamental burning rates fall off rapidly for concentrations away from the stoichiometric. Once a high pressure regime is established explosions are not confined to congested areas of a site. In many of the cases reviewed almost all the footprint of the cloud was exposed to pressures in excess of 2000 mbar (29 psi). In at least one case the cloud detonated, causing extremely severe damage over the area covered by the cloud)." (emphasis added)

PHMSA Conducted a Public Workshop on Liquefied Natural Gas (LNG) Regulations

The Workshop was conducted in Washington, DC in May 2016. Quoting excerpts from PHMSA's Statement of Mission (from the Workshop Website):

"Historically, most LNG facilities were peak shavers built to liquefy and store natural gas to be degasified and injected back into the pipeline during periods of peak demand … However, due to the recent abundance of domestic shale gas, LNG export terminals are now being constructed that liquefy vast volumes of natural gas. These facilities require significantly greater quantities of refrigerants to liquefy the natural gas than the amount typically used at peak shavers… Most refrigerant gases and blends used at the export facilities contain ethane, propane, ethylene, and iso-butane and are referred to as heavy hydrocarbons. These gases are similar to gases that have resulted in VCEs at petrochemical facilities…

The understanding of VCEs is evolving. PHMSA recognizes that significant quantities of heavy hydrocarbons present different risks than methane and seeks to better understand that risk. Prior to investigative work on the Buncefield accident, the prevailing understanding was that vapor clouds formed outdoors were unlikely to explode if ignited. Today it is understood that VCEs involving higher hydrocarbons have occurred in outside areas. This paper advances our understanding further. PHMSA sponsored the "Review of Vapour Cloud Explosion Incidents" report with the primary objective to improve the scientific understanding of vapour cloud development and explosion in order to more reliably assess hazards at large Liquid Natural Gas (LNG) export facilities… The aim of reviewing the particular incidents in this report is the extensive forensic evidence available that provides the information needed to study how the vapor cloud formed and ignited, the amount of overpressure exerted, and other information about the mechanism of VCE. This research was performed by the Health and Safety Laboratory (HSL) under a subcontract with the Oak Ridge National Laboratory, a United States Department of Energy (DOE) facility, and was supported by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA and DOE) and the United Kingdom Health and Safety Executive (HSE). The research's objective was to improve understanding of vapor development and explosions in order to more reliably assess hazards and safety measures at facilities that contain significant quantities of heavy hydrocarbons…

The technical review of the report was performed by uncompensated subject matter experts… The purpose of this independent review was to provide candid and critical comments to make the report as sound as possible… The review, comments, and draft manuscript remain confidential to protect the integrity of the deliberative process. The panel reviewed multiple drafts of the report, held several conference calls, and convened a meeting on May 17th (2016) in Washington, D.C. A presentation about the draft report was given at a public meeting, PHMSA's Public Workshop on LNG Regulations, on May 19th, 2016, in Washington, D.C. …" (emphasis added)

The 2018 PHMSA /FERC MEMORANDUM OF UNDERSTANDING

PHMSA is responsible for developing the regulations that specify the means of ensuring public safety in siting LNG terminals. The applicable regulation is 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. The present regulation was developed in the early Eighties to regulate LNG peak shaving and import terminals. Consequently, the present PHMSA regulation does not address the "new" hazards of vapor cloud explosions of heavier-than-methane hydrocarbons that are present in large quantities at LNG export terminals. So, during the period following my comments to FERC in 2015 on the UVCE hazard, and until very recently, I failed to understand why the 2015 JCET DEIS included an address of the UVCE hazard (not required by 49 CFR 193) by presenting the extensive predictions of explosion overpressure for heaver-than-methane hydrocarbon/air clouds that could be formed following accidental release at JCET. I remain uncertain why that action was taken, but I am increasingly concerned that the UVCE hazards present in the operation of LNG export terminals are effectively being ignored. My concern is that the order-of-magnitude-too-low predictions of the overpressures used by FERC to evaluate the VCVE hazard in the environmental impact statements for the JCET might result in the continued dismissal of the importance of this hazard for the JCET.

On August 31, 2018, the Federal Energy Regulatory Commission (FERC) and the Hazardous Materials Safety Administration within the U.S. Department of Transportation announced the signing of an agreement to coordinate the siting and safety review of FERC-jurisdictional LNG facilities. Quoting therefrom:

"The Memorandum of Understanding (MOU) establishes a framework for coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public safety impacts. The MOU provides that PHMSA will review LNG project applications to determine whether a proposed facility complies

with the safety standards set forth in PHMSA's regulations, and that PHMSA will issue a letter to FERC stating its findings regarding such compliance. FERC will then consider PHMSA's compliance findings in its decision on whether a project is in the public interest." (emphasis added)

It is my understanding that the JCET DEIS issued in 2019 does not state that FERC received an LOD (letter of determination) from PHMSA that presented its findings regarding compliance with the safety standards set forth in its regulations. It is further my understanding that the FERC/PHMSA MOU effectively requires PHMSA to issue such an LOD by the time the FEIS is completed.

My review of the Reliability and Safety section of the DEIS disclosed no direct reference to the UVCE hazard. It is as if the problem had either been decided as lacking further need of address or that some further address might be forthcoming by the time the EIS is completed.

I respectfully request that I be provided an answer to the following question: Given PHMSA's announcement in 2016 at the Public Workshop on LNG Regulation that 49 CFR 193 appeared to require updating to cater for the new (UVCE) hazards that attend Export Terminal operations, why has that announcement not led to any further analysis and evaluation in the 2019 JCET DEIS?

Unless that question can be answered satisfactorily, it appears that critical safety recommendations by PHMSA requiring changes to 49 CFR 193, backed up by extensive advice from the scientific expert community, are being ignored.

Who Required the UVCE Hazard to be Addressed in the 2015 JCET DEIS?

The only government source I have found for guidance regarding calculations of overpressure required to be presented in the 2015 JCET DEIS is in "Guidance Manual for Environmental Report Preparation, Volume II, LNG Facility Resource Reports 11 & 13 Supplemental Guidance, DRAFT, December 2015", prepared by FERC. Section 13.H.3, "Hazard Analysis Reports" of that draft appears to be the source of the requirement for explosion overpressure that appeared in the 2015 JCET Environmental Impact Statements. The requirement for explosion overpressures remains in the Guidance Manual for Environmental Report Preparation, FINAL, dated February 2017.

It is my understanding that the Draft FERC document providing guidance to JCET for providing VCE overpressure calculations was not based on the requirements of 49 CFR 193. It appears that FERC may have recognized the need to evaluate the UVCE hazards that could attend the operation of the JCET, and that those hazards should be considered in the JCET DEIS. I have no information about why FERC included the requirement to address UVCE hazards in their Guidance Document for preparation of Environmental Impact Statements. In any case, the "requirement" in FERC's Guidance Manual for Environmental Reports appears to demonstrate FERC's awareness of the importance of addressing the UVCE hazard.

The fact remains that the predictions of overpressure that were provided for the JCET DEIS in 2015 were stated therein to be made with the FLACS model, and although FLACS is approved for vapor dispersion calculations required by 49 CFR 193, it is my understanding that FLACS still has not been either evaluated or approved by PHMSA for explosion overpressure determination. If this is the case, then a major course-correction seems required, because comparisons of those (order-of-magnitude-too-low) overpressure predictions with documented measurements of overpressure data for a large number of UVCE events involving the same hydrocarbons, in similar amounts, and in similar atmospheric conditions, will demonstrate that the predictions utilized in the JCET environmental impact statements are in serious error.

<u>If this problem is not addressed, it appears likely that such errors accompanied by FERC's approval thereof will ignore the scientific expert advice that resulted from the PHMSA Workshop conducted in 2016. The effect will be to ignore extensive accident experience that demonstrates the potential for cascading explosions that could destroy the plant and possibly extend damages to the public beyond the facility boundary.</u>

CONCLUSIONS

49 CFR 193 Liquefied Natural Gas Facilities: Federal Safety Standards does not currently provide for adequate consideration of the hazards of Unconfined Vapor Cloud Explosion (UVCE) hazards that attend LNG Export Terminals handling and storing large quantities of heavier-than-methane hydrocarbons.

PHMSA conducted the Public Workshop on Liquefied Natural Gas (LNG) Regulations in Washington, DC, 19 May 2016. The principal purpose of the Workshop was stated to be the intention to address the need for updating 49 CFR 193 in order to cater for any new hazards that could be involved in siting LNG Export Terminals. The Workshop clearly identified the UVCE hazard as being the most important hazard present at Export Terminals that was not currently addressed adequately by 49 CFR 193.

PHMSA initiated a program to address the needs for changes in the regulation to provide for UVCE hazards. It appears that no progress has been forthcoming.

The new Draft Environmental Impact Statement (DEIS) for the Jordan Cove Export Terminal, just issued, continues to seriously underestimate vapor cloud explosion overpressures (damage) that could occur following credible releases of heavy hydrocarbons at the JCET site. The latest predictions that I am aware of appear to be an order of magnitude lower than are indicated by physical evidence of numerous documented UVCEs that have occurred worldwide with the potential to cause injuries and deaths to persons and result in destruction of the facility.

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are my fourth in a series submitted to the website established for the Public Workshop on Liquefied Natural LNG Regulations conducted in Washington, DC in May 2016. I appreciate the availability of this website for receiving comments from the public relating to the PHMSA's intention to update 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. However, I am very concerned that failure to ensure that the hazards attending LNG export terminals are adequately addressed will have catastrophic consequences.

The Workshop website includes two documents which are critically important because they explain clearly to all stakeholders the critical need for the regulations to be updated and effectively prescribe a path forward that would alleviate my concerns. Unfortunately, the website does not appear to have received the attention it deserves – to date the site has received only about a dozen comments, four of which are mine. The first document clearly defines the principal need that the Workshop was designed to address – a science-based evaluation of severe heavier-than-methane vapor cloud explosion (VCE) hazards that can exist in LNG export terminals. The second document, commissioned by PHMSA and presented at the Workshop, clearly provides that need.

I am concerned that comments that I filed with FERC in 2015 regarding the Environmental Impact Statement for the Jordan Cove Export Terminal in Oregon and the subsequent Health and Safety Executive Report "Review of Vapor Cloud Explosion Incidents" presented at the Workshop in 2016 are being ignored. In my opinion, a potential error in overpressure calculations presented in the Jordan Cove EIS portends the possibility of a VCE explosion that could destroy the plant and endanger the Public beyond the facility boundary.

Excerpts from PHMSA's Statement of Mission (from the Workshop Website)

"Historically, most LNG facilities were peak shavers built to liquefy and store natural gas to be degasified and injected back into the pipeline during periods of peak demand … However, due to the recent abundance of domestic shale gas, LNG export terminals are now being constructed that liquefy vast volumes of natural gas. These facilities require significantly greater quantities of refrigerants to liquefy the natural gas than the amount typically used at peak shavers… Most refrigerant gases and blends used at the export facilities contain ethane, propane, ethylene, and iso-butane and are referred to as heavy hydrocarbons. These gases are similar to gases that have resulted in VCEs at petrochemical facilities…

The understanding of VCEs is evolving. PHMSA recognizes that significant quantities of heavy hydrocarbons present different risks than methane and seeks to better understand that risk. Prior to investigative work on the Buncefield accident, the prevailing understanding was that vapor clouds formed outdoors were unlikely to explode if ignited. Today it is understood that VCEs involving higher hydrocarbons have occurred in outside areas. This paper advances our understanding further. PHMSA sponsored the "Review of Vapour Cloud Explosion Incidents" report with the primary objective to improve the scientific understanding of vapour cloud development and explosion in order to more reliably assess hazards at large Liquid Natural Gas (LNG) export facilities… The aim of reviewing the particular incidents in this report is the extensive forensic evidence available that provides the information needed to study how the vapor cloud formed and ignited, the amount of overpressure exerted, and other information about the mechanism of VCE. This research was performed by the Health and Safety Laboratory (HSL) under a subcontract with the Oak Ridge National Laboratory, a United States Department of Energy (DOE) facility, and was supported by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA and DOE) and the United Kingdom Health and Safety Executive (HSE). The research's objective was to improve understanding of vapor development and explosions in order to more reliably assess hazards and safety measures at facilities that contain significant quantities of heavy hydrocarbons…

The technical review of the report was performed by uncompensated subject matter experts… The purpose of this independent review was to provide candid and critical comments to make the report as sound as possible… The review, comments, and draft manuscript remain confidential to protect the the integrity of the deliberative process. The panel reviewed multiple drafts of the report, held several conference calls, and convened a meeting on May 17th (2016) in Washington, D.C. A presentation about the draft report was given at a public meeting, PHMSA's Public Workshop on LNG Regulations, on May 19th, 2016, in Washington, D.C. …"

Excerpts from the Executive Summary of "Review of Vapour Cloud Explosion Incidents"

"**T**his review of major vapor cloud incidents has been jointly commissioned by the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and the UK Health and Safety Executive (HSE). The primary objective was to improve understanding of vapor cloud development and explosion in order to examine the potential for these hazards to exist or develop at LNG export plants that store substantial quantities of these flammable gases for use in the liquefaction process or as a by-product from the liquefaction …

This review has not found any historical records of LNG (methane) vapor cloud explosions in open areas with severity sufficient to cause secondary damage to tanks and pipes and consequently rapid escalation of an incident from a minor process leak to a major loss of inventory.

On the other hand some LNG sites (especially export sites) also hold substantial amounts of refrigerant gases and blends containing ethane, propane, ethylene and iso-butane. Higher hydrocarbons may also be produced and stored on LNG export sites as by-products of gas condensation. There are numerous examples of Vapor Cloud Explosions (VCEs) in open areas involving these higher molecular weight materials and the storage and use of higher molecular weight hydrocarbons on LNG export sites which may if not managed adequately introduce an additional set of incident scenarios in which VCEs trigger rapid escalation of loss of containment.

This study involves a review of 24 major VCE incidents focusing on source terms, cloud development and explosion mechanics. The incidents studied are split between permanent fuel gas (C2-C4 (e.g. LPG) and volatile liquids C4-C6 (e.g. gasoline). The source terms for leaks of gases and liquids are different but once a stable current of cold heavy vapor forms, the subsequent development of LPG and gasoline clouds are similar…

An important finding from the review is that a high proportion of vapor cloud incidents occurred in nil/low wind conditions. By the term "nil/low wind" we mean a wind that was so weak close to the ground that it only detrained (stripped away) a small proportion of the vapor accumulating around the source … Rather than being picked up and moved downwind, the vapor flow in this case was gravity driven; spreading out in all directions and or following any downward slopes around the source.

In many of the cases examined, 50% (12/24), there is clear evidence from the well-documented transport of vapor in all directions and/or meteorological records that the vapor cloud formed in nil/low wind conditions. In a further 21% (5/24), the pattern of vapor suggests nil/low wind conditions but there is insufficient data available to be sure … incidents in nil/low wind conditions apparently make up the majority of historical records of the most serious VCEs… In nil/low wind conditions the cloud continues to grow throughout the time that the tank takes to empty… The maximum area covered by the flammable cloud is typically several hundred times greater in nil/low winds condition than in light winds.

<u>The implication of this type of analysis is that if the density of ignition sources is constant and quite low in the area around the tank the chances of ignition in nil/low wind conditions would be hundreds of times greater for a given release. This illustrates why nil/low wind conditions dominate records of major vapor cloud incidents even though the weather frequency is low. Losses of containment in nil/low wind conditions are also particularly dangerous because a highly homogeneous cloud can be formed that may spread by gravitational slumping (without significant dilution) for hundreds of meters… A very large cloud that is all close to the stoichiometric ratio increases the risk of flame acceleration to a high pressure regime capable of seriously damaging storage and process facilities, when compared with clouds that are entraining air because of wind-driven dilution. Thjis is because fundamental burning rates fall off rapidly for concentrations away from the stoichiometric . Once a high pressure regime is established explosions are not confined to congested areas of a site. In many of the cases reviewed almost all the footprint of the cloud was exposed to pressures in excess of 2000 mbar (29 psi). In at least one case the cloud detonated, causing extremely severe damage over the area covered by the cloud).</u> (emphasis added)"

When is the LNG Regulation Update Expected?

It has been more than two and a half years since the Public Meeting on LNG Regulation was held. My attempts to get information on the schedule for Regulation updating have not been encouraging. I have learned that PHMSA has addressed the need for a written protocol to assess the verity and utility of the computer-calculated explosion overpressure predictions that were the means of addressing the vapor cloud explosion (VCE) hazard in the Environmental Impact Statement(s) filed for the Jordan Cove Terminal in Oregon. I should note that these comments are directed primarily to the environmental impact statements relating to the Jordan Cove Project, which I have previously commented on; however, the scientific information presented on the Workshop website that I am referring to should be considered applicable to LNG Export Terminals in general. I understand that the development of a written protocol (for explosion model verification) requires that funding be expedited. I also understand the difficulties faced by the Regulatory Agencies in the present political climate. Meanwhile, LNG export terminals are being approved and some are operating. I am concerned that errors are being made in the calculation of overpressures in the design spills that are being considered in environmental impact statements for LNG export terminals now processing applications for siting. Such errors can put these very expensive facilities at risk of severe vapor cloud explosions that could result in cascading loss of containment events that could destroy the facility and present important hazards to the public beyond the plant boundaries. Accordingly, I am convinced of an urgent need for updating of the LNG regulations.

Please let this comment serve as my request that funding be provided as soon as possible to PHMSA to determine whether the calculations now being presented for LNG facility siting can be evaluated by testing against the applicable explosion events documented in the HSE report. In my opinion the HSE report contains sufficient validated scientific data for numerous severe VCEs involving the same or similar fuels and amounts thereof. I believe that a careful, science-based, evaluation of the calculations of overpressures in VCEs that have been presented in the Jordan Cove proceedings using the HSE report will provide a method for dealing with this urgent problem that is not cost prohibitive. I believe the problems underlying my concern have been addressed carefully in the HSE report. I conclude that actions required to alleviate these concerns are doable and can be expedited using the HSE report that has been commissioned by PHMSA .

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are a further addition to my comments to the Public Workshop on Liquefied Natural LNG Regulations site on July 28, 2016 and September 22, 2018.

I stated in my comments of September 22, 2018 that I am very concerned that our current regulatory measures concerning siting of LNG export terminals be developed by decision-makers that are fully informed regarding the public safety impacts involved.

Based on information I have learned since September 22, 2018, I want here to clarify my understanding of the process that took place in the preparation of the Environmental Impact Statements for the Jordan Cove LNG Export Terminal, and I respectfully request that PHMSA inform me of any faults in that understanding.

In 2015 FERC published a draft notice of their intent to update their guidance document on preparation of environmental impact statements. The earlier guidance document (2002) did not include any consideration of explosion overpressure hazards. The draft (dated 2015) clearly specified the direction to applicants to prepare calculations of VCE explosion overpressures that could result following the Design Spills considered, and the draft was approved and issued in 2017 – still containing the directions to the applicant to prepare the explosion overpressure hazards calculations.

To my knowledge, PHMSA's regulations on LNG Terminal siting did not in 2015 and still do not require Vapor Cloud Explosion (VCR) overpressure calculations.

The FLACS Model was approved for vapor cloud dispersion exclusion zones by PHMSA based on FLACS' satisfactorily meeting the requirement of PHMSA's written protocol.

The written protocol used to approve FLACS for calculating vapor cloud dispersion zones does not address the suitability of FLACS for calculating VCE overpressures.

I am very concerned that the afore-mentioned information could indicate that the FLACS model used for calculating the VCE overpressures presented in the Jordan Cove LNG Export Terminal Environmental Impact Statements has not received adequate scientific peer review.

I appreciate this site remaining available for comments relating to the 2016 PHMSA Public Workshop on Liquefied Natural Gas (LNG) Regulations.

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are an expansion of my earlier comments to the Public Workshop on Liquefied Natural LNG Regulations site on July 28, 2016, which I stand by. They are also intended as a response to the joint news release of August 31, 2018 by PHMSA and FERC:

FERC, PHMSA Sign MOU to Coordinate LNG Reviews

Quoting the MOU, "The MOU establishes a framework for coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public safety impacts ".

I understand the importance to us all of expeditious and timely handling of LNG Export Terminal applications, but I am very concerned that our current regulatory measures be developed by decision-makers that are fully informed regarding the public safety impacts involved. I realize the gravity of this statement, and I have struggled with the decision to put such questions of uncertainty on the table. But I have been unable to satisfy myself that my concerns are unwarranted. Therefore, I appreciate this opportunity to state my concerns.

Please let me repeat that I stand fully behind the comments I submitted to this site on July 28, 2016, as well as all of my previous comments submitted to FERC and PHMSA. But more importantly, I want to clearly identify here my increasing concerns that our regulatory process is failing to satisfactorily consider fully the accident consequences that attend the operation of LNG Export Terminals that must be considered in the public interest. Please consider the following statements, which I trust are factual. If PHMSA notifies me that I am in error, I will promptly refile accordingly.

- The current LNG regulation 49 CFR 193 was developed for application to the evaluation of hazards attending Import Facilities.
- 49 CFR identifies only two hazard exclusion zone requirements; a vapor dispersion zone and a fire radiation zone. The regulations require that the maximum lateral extent of these zones must not exceed the distance to the property boundary.
- The current regulation does not address vapor cloud explosion hazards. My understanding of the basis for this policy is the long-accepted premise that LNG vapor (being essentially methane, that is, not containing heavier (higher molecular weight) hydrocarbons such as propane, butane, etc.), will not explode if uncontained.

- For import terminals, there are normally no situations where there is significant risk of release of large amounts of heavier-than-methane hydrocarbons.
- But, for export terminals, the gases entering the facility for liquefaction may (and typically do) contain significant amounts of high-explosion-risk hydrocarbons that must be stored and handled, thus presenting new risks not ordinarily attending import terminals.
- <u>The requirement for only two exclusion zones, dispersion and thermal radiation zones, for import terminals does not address the risks of explosion of unconfined gas air clouds that can occur at export terminals.</u>
- My comments to FERC and PHMSA on this subject have been directed thus far primarily to the Jordan Cove Export Terminal proposed for the coast of Oregon. The remaining points in these comments are largely presented for consideration with the Jordan Cove Facility only. However, it should be anticipated that such hazards could attend any of the LNG export terminals currently operating or under consideration throughout the world.
- As I understand it, there is no requirement at present in 49 CFR 193 to address the unconfined vapor cloud explosion (UVCE) risk.
- However, as exemplified by the Draft and Final Environmental Impact Statements for Jordan Cove, the applicants included calculations to provide for the formation of very large clouds of heavier hydrocarbon gases than methane <u>which are known to cause damaging explosion overpressures</u>. It is my understanding that the calculation of the overpressures was done with a Computer Code called FLACS. The results of the calculations were then used to justify the statement in the Environmental Impact Statements that the explosion damage would not extend off-site. Along with Professor James Venart of the University of New Brunswick (now deceased) I filed comments with FERC questioning the accuracy of those conclusions in 2015.
- Subsequently, PHMSA held a public workshop in Washington in mid-2016 which announced PHMSA's intent to consider the need for updating the LNG regulations for proper consideration of the hazards that attend LNG export terminal operations.

The Current Situation (as I understand it)

It appears that the FLACS Computer Model used in support of Jordan Cove applications was used to calculate the vapor cloud explosion overpressures that could have been realized for the design spills considered. My understanding is that the calculations using the FLACS model are important to the final decision by FERC to grant approval to both the DEIS and the FEIS for Jordan Cove. For various reasons, the project did not proceed, but it has been announced that a new DEIS will be issued in February of 2019.

In view of the importance of the facts presented, coupled with the policy now adopted by PHMSA for such codes as FLACS to be designated **Proprietary** using their designation as Critical Energy Infrastructure Information (CEII), it appears to me that the public interest is not being served by the Agency's failure to sufficiently investigate the scientific validity of FLACS for determining the damage that might result from the very spills of heavier than methane hydrocarbons that Jordan Cove argued could be released, specifically mixed refrigerant hydrocarbons and ethylene, both of which have been shown to cause violent Unconfined Vapor Cloud Explosions.

Here are three more inputs which I believe support my concerns:

- LNG Regulation 49 CFR 193 is based on the determination of the extents of exclusion zones for vapor dispersion and fire (thermal) radiation using mathematical models which must be approved by PHMSA.
- As I understand it, vapor dispersion models are now approved by PHMSA only if the models meet the requirements of PHMSA-specified written protocols designed for the purpose.
- <u>To my knowledge there has not been made available to the public a protocol that must be met for PHMSA's approval for the use of FLACS to predict vapor cloud explosion overpressures</u>. This leaves me with the concern that the FLACS model has not been sufficiently evaluated for such regulatory use, considering the very high stakes involved.

Thank you for the opportunity to express my concerns about this situation, which I believe is of critical importance to us all.

Comment by Jerry Havens
Distinguished Professor of Chemical Engineering
University of Arkansas

I am speaking as a concerned scientist.
My comments are not to be attributed to the University of Arkansas.

I attended the LNG workshop at DOT Headquarters in Washington on May 18 and 19, 2016. My comments are directed to the plans previewed by PHMSA at the workshop for updating the federal regulatory requirements for safe siting of LNG facilities; especially relating to the workshop presentations made by Drs. Graham Atkinson and Simon Gant of the British Health and Safety Laboratories (HSL) regarding predictive modeling of flammable vapor cloud formation, dispersion, and explosion hazards.

I understand that HSL is under contract to PHMSA to provide an assessment of specific needs that should be addressed by PHMSA for its planned updating of LNG Regulation 49 CFR 193. I do not know the specific requirements of the contract with HSL, but it seemed strongly suggested at the workshop that HSL is considering at least two critical needs for LNG facility siting regulation evaluation and updating:

- Unresolved questions about the potential at LNG storage terminals for unconfined vapor cloud explosion (UVCE), with emphasis on the increased potential for severe explosions involving heavier-than-methane hydrocarbons used and stored in large amounts in LNG export terminals. (Workshop presentation by Dr. Atkinson)
- Protocols for approval of mathematical models for LNG vapor cloud formation, dispersion, and explosion potential, particularly for heavier-than-methane hydrocarbons. (Workshop presentation by Dr. Gant)

My comments focus on the methods used to determine consequences of UVCEs that could follow the design spills required to be considered by 49 CFR 193. I believe the following three issues (in caps), all of which are closely coupled in the determination of vapor cloud explosion potential, are of highest priority for updating the LNG regulations.

MATHEMATICAL MODELS FOR VAPOR DISPERSION CONFINED BY FENCES AND UVCE OVERPRESSURE POTENTIAL REQUIRE THOROUGH SCIENTIFIC VETTING

The main purpose of my comments is to request PHMSA to address concerns that have been raised that some of the mathematical modeling methods currently in use can produce results that severely underestimate vapor cloud explosion hazards (consequences) to the public. I am very concerned that PHMSA's current procedure for determining the hazards attending large-scale LNG Export Terminals, including the present protocol for approval of vapor dispersion models for such use, is seriously flawed, particularly regarding UVCE hazards.

Proprietary Models

The current model approval process relies on provision to PHMSA by the applicant (for model approval) of evidence that the proposed model meets PHMSA requirements for scientific correctness as well as requirements for satisfactory model agreement with a PHMSA supplied list of field and laboratory experiments that have been documented. The most serious flaw in the current procedure, in my opinion, is that because the protocol allows approval of modeling methods that are proprietary, and thus not subject to independent scientific-peer review, neither PHMSA nor the public can confidently determine whether the models are suitable for purpose. The result is that the public is not provided the following information about the hazard-modeling process, all of which is necessary to make a science-based evaluation of the model predictions that form the basis for FERC's approval or disapproval of proposed LNG terminals:

- Details of data input to the model(s),
- Detailed results produced by the model(s), and,
- most importantly, a transparent description of the methods used in the models that is suitable for examination and scientific review to ensure that the methods are not used improperly.

The use of proprietary models denies the public an effective means of ensuring that errors in model application are not committed accidentally or intentionally. Such a process portends danger to the public. There is no question that the hazards attending the handling and storage of extremely large quantities of potentially flammable/explosive materials in LNG facilities, if the hazard determinations are not accurate, could result in catastrophic damages extending beyond facility boundaries.

PHMSA has a single means of ensuring that the decisions for approval of the safety provisions claimed are not subject to error – a scientific peer review process. There must be a means developed to insure that the public is provided information sufficient to independently verify the accuracy and applicability of the model predictions that determine FERC's decision for or against LNG facility approval. The importance of requirements for model transparency can only increase as the scientific tools for predicting hazardous materials risks and consequences become more complex and difficult for evaluation by the regulators and the public.

Past Experience: "Sub-Model" SOURCE5

A brief review of one of PHMSA's documented actions taken to correct misuse of hazard-models illustrates the difficulties the agency faces in enforcement of model use that is based on correct science and is accurate. The "case" described below also provides a pertinent example of the critical need to ensure that so-called "sub-models" (subordinate parts of the parent models) that are required to quantify the risk and/or consequences of the "design" spill are also based on correct science and are accurate. This is particularly important presently; some of the issues that I believe are now being handled incorrectly and which were described in my comments to FERC in January/February 2015 regarding the DEIS for the Jordan Cove LNG Export Terminal are due to use of such sub-models.

The vapor dispersion models approved for determination of vapor cloud exclusion zones by PHMSA require specification as input the rate at which the gas enters the atmosphere. Historically, the largest "design spills" for which vapor cloud exclusion zones must be predicted are liquid spills into impoundments, necessitating estimation of the evaporation rate from the LNG (liquid) released as input to the vapor dispersion model. Until about 2010, during which time the LNG vapor dispersion model DEGADIS was used widely, a sub-program called SOURCE5 was used to compute gas input rate to the dispersion model. There appeared statements in the scientific literature as well as comments to Draft Environmental Impact Statements that SOURCE5 contained assumptions that were erroneous and that resulted in severe underestimation of the "source term" (the gas rate introduced to the atmosphere) which led to severely underestimated vapor cloud dispersion distances.

PHMSA responded and processes were put in place to provide scientific review of several sub-models, including SOURCE5. One of the resulting scientific reports that contributed to PHMSA's decision to prohibit further use of SOURCE5 was prepared by the British Health and Safety Laboratory (HSL). See Ref. 1 below. For brevity, I quote a single brief statement from Appendix A of HSL's report which I believe says everything that is necessary to justify, indeed require, PHMSA's decision to prohibit further use of SOURCE5:

> *In summary we find that the suite of models embodied in SOURCE5 do not have a sound physical basis. In fact it is doubtful that one can get an accurate picture of a scenario as complicated as those considered here if one restricts oneself to simple algebraic e quations s uch a s t hose c onsidered by SO URCE5. Some of t he predictions of t he m odel, e specially t he l ack of dilution of t he v apour be fore i t achieves t he bund w all he ight, ar e expected t o r esult i n m arkedly o ptimistic prediction of hazards.*

I used this short excerpt because it so effectively summarized HSL's finding. Lest the reader be misled by the brevity and straightforward simplicity of this statement that justified PHMSA prohibiting further use of SOURCE5, I think a few remarks are in order. Readers willing to take the time to examine the HSL Report from which the excerpt is quoted will find that the examination of the model by HSL was thorough and painstaking. The expertise and knowledge required for an assessment of complex mathematical models resides in relatively few independent organizations, and the resulting action prohibiting further use of SOURCE5 could not have been achieved without PHMSA's request to a neutral scientific body for advice and interpretation. I appreciate the agency's concern that the amount of time and effort required by the model evaluation by HSL was expensive to the U.S. taxpayer. However, such costs are necessary as part of any government regulatory process that relies on expert scientific advice for decision making, particularly if those decisions directly impact public safety. Without such actions taken by the regulatory authority, the public cannot be confident of predictions that FERC accepts to approve or disapprove a facility.

THE PRACTICE OF CONFINEMENT OF VAPOR CLOUDS WITH GAS-IMPERMEABLE FENCES SHOULD BE EVALUATED FOR POTENTIAL TO INCREASE EXPLOSION DAMAGE

The use of gas-impervious vapor fences is relatively new to the industry; it appears to be resulting more frequently associated with requests for approval for siting of very large facilities which cannot economically provide satisfactory exclusion distances to the facility property line without resort to such "vapor cloud mitigation practices". The majority of LNG Export Terminals now being considered have requested approval by FERC of vapor-impervious fences placed strategically to limit flammable vapor cloud travel beyond the applicant's property line. Such practices raise important (unanswered) questions about the increase in the severity of vapor cloud explosions that can result from such partial confinement. Based on my review of the Jordan Cove project DEIS, it appears that FERC has not considered the potential of such fences, some of which are 40 feet tall and constructed with reinforced concrete, to increase explosion overpressure damage. In my opinion this neglect of explosion science knowledge is wrong.

CURRENT MODELS FOR EXPLOSION DAMAGE OF VAPOR CLOUDS ARE INSUFFICIENTLY TESTED AND MAY LEAD TO NONCONSERVATIVE HAZARD PREDICTIONS

After I learned of the planned PHMSA workshop and that PHMSA had contracted with HSL to evaluate some of the concerns I had raised in my comments to FERC, I developed a better understanding of the situation which I believe should be considered by PHMSA as they proceed with the regulation updating process. I believe the issues described here deserve highest priority, since unconfined vapor cloud explosions involving heavier-than-methane hydrocarbons handled and stored in large quantities in LNG export facilities pose the potential for catastrophic cascading explosion damages resulting in complete destruction of the facility and potential for danger to the public beyond the facility boundaries.

Focusing on Jordan Cove EIS Critical Issues: Effects of Vapor Fences and Use of Proprietary Models to Predict Explosion Overpressure

Expert advice for preparation of draft environmental impact statements is generally provided to applicants for siting approval (such as Jordan Cove) by consultants who are practiced in making such determinations using computer modeling methods. Such calculations are now almost exclusively made using complex mathematical modeling tools – the use of computational fluid dynamics (CFD) computer models has become widespread in the LNG industry/regulatory community in the last two decades. This practice, however sophisticated and rapidly developing it may be, is relatively new and untested for application to the strongly coupled complex phenomena of atmospheric dispersion and combustion/explosion dynamics. Experimental verifications of such model predictions as complex as those currently appearing in environmental impact statements is increasingly expensive and difficult to achieve.

In my opinion, the reality of the situation is this: The prediction of explosion overpressure damage that could result if a very large design spill formed a flammable vapor cloud in near-calm conditions and confined by vapor fences is presently fraught with uncertainty; so much so that the scientific community has insufficient confidence in such predictions unless they are verified, at least in part, by experiment. But these new “complex” models are the product of private research and development efforts, in the present case by consulting companies that must deal directly (for the project applicant) with PHMSA and FERC. The result is that such tools are now being approved by PHMSA with a proprietary designation. This is understandable, if not necessarily justified, as the companies are motivated to protect their investment in the required model development process.

It is this author’s experience that until the current model protocol process was instituted (accepting proprietary models for regulatory use), there has always been a strong reluctance by regulators to allow such models that are not available (at reasonable cost) to the public, or the public’s agent, for careful scientific scrutiny. SOURCE5, although developed by private interests, was not prohibitively expensive and could be obtained for careful analysis with a reasonable effort by the public. That availability enabled the criticisms that led to the model’s careful scientific vetting and the prohibition of its further use. The new complex models being adopted are prohibitively expensive to the public and protected as proprietary as well. There must be some means of ensuring that such complex, untested, calculations are thoroughly vetted by independent scientific parties responsible to PHMSA. In my opinion, proceeding with the current hazard evaluation processes now being approved by FERC cannot be justified.

Low or No--Wind Condition Concerns Made Worse with Cloud Confinement

Revisiting the Jordan Cove DEIS in preparation of these comments, I verified that the vapor cloud travel distances that were determined using the recently approved FLACS model, essentially none of which reach beyond the JC property lines, resulted not from dispersion (or lack thereof) but from the use of vapor fences that confine the cloud to the property controlled by the applicant. The vapor cloud does not proceed beyond the boundaries because it is stopped by a vapor fence. Because the cloud cannot penetrate the fence, it accumulates on the site. Although the fences are not continuous (laterally), they prevent the cloud from advancing beyond most of the boundaries. The result is confinement of the gas on the site, where the depth (thickness) tends to increase until the spill ends and the liquid all evaporates. Then, under very low or no-wind conditions, the gas cloud pretty much sits there (which can be a long time if there is no wind to increase vertical diffusion of the gas) unless it is ignited. But, if it is ignited and the flammable concentration range of the gas includes large parts of the cloud, the condition is set up for a catastrophic explosion.

The Volume of the Gas Cloud that is within the Flammable Concentration Range is a Strong Determinant of the Damaging Explosion Overpressure

The confinement of the cloud when it is formed with very little wind (to increase dispersion) can result in the cloud becoming highly concentrated (in flammable gas) throughout. In all four of the catastrophic explosions described in my comments to FERC (and those described by Dr. Atkinson at the Workshop), there were very large parts of the cloud with gas concentrations in the flammable range. The gas concentration distribution in the cloud strongly determines the severity of the fire or explosion that can result if the cloud is ignited. If the entire cloud is below the lower flammability concentration of the gas, none of it will ignite and there will be no fire or explosion. If the source of ignition is in a region of the cloud where the gas concentration is above the upper flammability limit, ignition will not occur at that location. If ignition occurs in a cloud region where the concentration lies between these limits and there are nearby regions where there are higher concentrations (above the upper flammability limit) the cloud will continue to burn through those regions. In any case the flame advance will only be stopped when the concentration of the cloud (at that location) drops below the lower flammable limit.

Revisiting FLACS and Sub-Model Q9 Used for Jordan Cove EIS

There exists evidence in the open scientific literature that the FLACS vapor-dispersion mathematical model, which includes a specific sub-model called Q9 that is used in part to calculate explosive overpressures, has not been subjected to a satisfactory scientific peer-review process designed to prevent its misuse. In preparation for these comments, I found a publication in the Institution of Chemical Engineers (IChemE) Symposium Series which presents an evaluation of the combined use of FLACS and Q9 for explosion modeling (See Ref. 2 below).

There are striking similarities in the IChemE paper with statements that appeared in criticisms of SOURCE5. Again, for brevity, I have selected brief comments from the IChemE paper about Q9 that indicate serious questions about its overall applicability to the prediction of UVCE explosion overpressure damage in complex plant environments:

> *Q9 is a volume measure which accounts for the effects of gas concentration by weighting the volume with the effect of burning velocity and expansion ratio. Experiments showed that burning velocity varies with concentration ... For hydrocarbons, burning velocity is maximum at or near stoichiometric concentration of 1 and dropping off rapidly as gas concentration is rich ... or lean ..., reaching zero at UFL and LFL.*
>
> *We found that Q9 measures are being used increasingly by consultants. We are concerned that there has not been work to verify that this approach is indeed correct. Our observation is that there appears to be little fundamental understanding of the Q9 measures by consultants we encountered. Its application is based on a belief that since there is a varying gas concentration in a gas cloud formed from pressurized gas release, assuming a uniform gas cloud concentration is thus 'over-conservative', and using Q9 would remove this perceived 'over-conservatism'. As we see... this is not necessarily so.*
>
> *Superficially, Q9 seems to be the most accurate measure out of the three (we reviewed) as it accounts for the well known effect of gas concentration on flame speed and expansion ratio. It may be a surprise that our results showed that the Q9 measure performs poorly. ... one should not confuse complexity and accuracy.*
>
> *Size of the gas cloud – Limiting the flammable gas cloud to a smaller effective volume reduces the effect of flame acceleration over a larger distance and over a longer period of time that that produced by larger cloud volumes and could lead to lower and the wrong distribution of overpressure .... Another reason for psssible underestimation of flammable volume is that volumes with rich gas mixtures can be diluted with air or with lean gas mixtures during the course of a gas explosion, rendering the rich mixture closer to the stoichiometric ratio of 1. Applying the Q9 method blindly, it is possible to reach a conclusion that a very large leak of flammable gas would not pose a hazard* (emphasis added).
>
> *Any methods used should be verified against experimental data as far as possible. It should be the duty of the model developer or user of the model to verify any new methods against available data ...*
>
> *This work does not support the use of Q9* (emphasis added).

While the referenced IChemE Symposium paper is not equivalent to a thorough scientific peer review, it does qualify as an Industry/Academia-led evaluation of current methods for determining flammable gas volumes to be considered in explosion modelling. Most importantly, the paper provides results of a technical expert-evaluation of the Q9 model for estimating equivalent stoichiometric volumes of the flammable cloud volumes that were predicted for the heavy hydrocarbon design spills presented in the Jordan Cove Export Terminal EIS. Similar queries about SOURCE5 were dealt with by PHMSA's request to an independent scientific body for assessment. I believe the questions raised here about Q9 (as used with FLACS) deserve similar scrutiny, and I hope that PHMSA will commission such a review.

A Closing Comment on Accidental vs. Intentional Events

There were suggestions during the Workshop that incorporation of quantitative risk assessment (QRA) procedures were being considered by PHMSA for updating 49 CFR 193, perhaps by incorporation of LNG-QRA procedures in NFPA 59A.

I believe it is just as important that the regulations begin to address the burgeoning problem of the potential for intentional acts against LNG facilities to cause extremely serious fire and explosion cascading events.

It is clear that reliance on design of LNG facilities to minimize the probability (measure of likelihood) of accidental occurrences is turned on its head when intentional acts are considered. A simple fact plagues all of the energy industry, including the nuclear power and weapons sectors; it is relatively easy to assemble an explosive device that can be made to explode. Designing the same device to ensure that it doesn't explode is another matter entirely.

We can start by doing a better job in applying our scientific knowledge to minimize the extent to which we provide opportunities to those inclined to take advantage. The incorrect use of our scientific tools, so as to mistakenly conclude that the design under consideration is a benign one, leads us in the wrong direction.

Conclusions

The concerns laid out here exemplify why it is impossible for complex mathematical models used in regulatory determinations of questions bearing on public safety, in the absence of transparent independent scientific review, to be fairly and adequately vetted for such use. These concerns were laid out by Professor Jim Venart, now deceased, and me in response to the Draft Environmental Statement (DEIS) for the proposed Jordan Cove LNG Export Terminal in Coos Bay, Oregon. See Ref 3 and 4. I stand by my comments submitted to FERC, which I subsequently provided PHMSA for their information. While FERC acknowledged my comments when the FEIS was issued for the Jordan Cove Export Terminal Project, their reply was unsatisfactory in that it did not address the technical questions for which I had requested answers.

This is more than a debate about scientific theories of the hazards of UVCEs. It is not about "opinions" regarding the hazards of UVCE. My comments to FERC provided verified information that at least four catastrophic UVCE events, all occurring under conditions that clearly justify their description as worst-case accidents (therefore normally considered highly improbable), have occurred in the past decade. See Ref 3 and 4. Those incidents, and additional ones, were also described by Dr. Atkinson at the workshop.

There must be increased transparency of PHMSA approved mathematical modeling methods, especially those used for public-safety-regulation purposes, to prevent the public being misled. In the absence of such transparency there is little likelihood that more detailed and extensive alterations to the regulation will address the primary problem underlying these concerns.

So, my comments focus on a single question - Are the mathematical models which are being used as a basis for approving construction of LNG terminals, with the present focus on Export rather than import, being subjected to the necessary scientific scrutiny to ensure that the hazards involved are being correctly identified? I do not believe they are.

References

1. LNG source term models for hazard analysis, A review of the state-of-the-art and an approach to model assessment, Appendix A – Model Assessment Reports for GASP and SOURCE5; Dr DM Webber, Dr SE Gant, Dr MJ Ivings & SF Jagger, Health and Safety Laboratory, Harpur Hill, Buxton, Derbyshire SK17 9JN (2010)
2. Simplified flammable gas volume methods for gas explosion modeling from pressurized gas releases. A comparison with large scale experimental data. V.H.Y. Tam[1], M. Wang[1], C.N. Savvides[1], E. Tunc[2], S. Ferraris[2], and J.X. Wen[2]; [1]EPTG, BP Exploration, Chertsey Road, Sunbury-on-Thames, TW16 7LN, UK; [2]Faculty of Engineering, Kingston University, Friars Avenue, London, SW15 3DW, UK; IChemE Symposium Series No. 154, 2008
3. 1-14-2015 filing submitted to FERC by Jerry Havens and James Venart under CP13-483. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150114-5038
4. 2-6-2015 filing submitted to FERC 2-6-2015 - Supplementary Comment with Questions by Jerry Havens and James Venart under CP13-483. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150206-5040

Exhibit 4

From: Springer, Laura M LCDR/U.S. Coast Guard
Sent: Tuesday, May 15, 2018 12:39 PM
To: Jody McCaffree
Cc: Crowell, Ben W LCDR/U.S. Coast Guard; Griffitts, Thomas CAPT/U.S. Coast Guard; Dunn, Brian/U.S. Coast Guard
Subject: RE: [Non-DoD Source] FW: Connecting re Jordan Cove LNG Export Project

Good Day,
Thank you for your concern, the Letter of Recommendation is the USCG's input into this process and FERC is the final permitting authority. The draft Environmental Impact Statement will be put out for comment and FERC welcomes these comments (www.FERC.gov & docket #CP17-495-000).

I have made record of your comments. Please remember to include them and any additional comments when FERC issues their draft EIS. Also, please note that a limited access area (safety zone) has not yet been determined for this project and if drafted will be put out for public comment.

Respectfully,
LCDR L.M. Springer

From: Dunn, Brian/U.S. Coast Guard
Sent: Tuesday, May 15, 2018 12:16 PM
To: Jody McCaffree
Cc: Springer, Laura M LCDR/U.S. Coast Guard; Crowell, Ben W LCDR/U.S. Coast Guard
Subject: FW: [Non-DoD Source] FW: Connecting re Jordan Cove LNG Export Project

Ms. McCaffree,

The Coast Guard point of contact is LCDR Laura Springer at Marine Safety Unit Portland. I have copied her, so she will have the information you have provided. She can be reached by e-mail at [redacted] or by phone at [redacted].

Brian L. Dunn
US Coast Guard Bridge Program (CG-BRG)
[redacted]

From: Jody McCaffree
Sent: Monday, May 14, 2018 12:11 PM
To: Springer, Laura M LCDR/U.S. Coast Guard
Subject: FW: Connecting re Jordan Cove LNG Export Project
Attachments:
LNG Hazard Zones of Concern FEIS 4.7-3 Revised -3 (4).pdf (224KB);
029FERC_Exb32_Explosive-LNG-issues-grab-PHMSA-attent.pdf (621KB)

FYI…

From: Jody McCaffree
Sent: Monday, May 14, 2018 12:06 PM
To: Springer, Laura M LCDR/U.S. Coast Guard
Cc: Dunn, Brian/U.S. Coast Guard; Crowell, Ben W LCDR/U.S. Coast Guard; Jody McCaffree
Subject: FW: Connecting re Jordan Cove LNG Export Project
Attachments:
LNG Hazard Zones of Concern FEIS 4.7-3 Revised -3 (4).pdf (224KB);
029FERC_Exb32_Explosive-LNG-issues-grab-PHMSA-attent.pdf (621KB)

Please advise as to who is currently handling LNG hazards and the safety and security of the Jordan Cove LNG for the Coast Guard because I get tired of constantly sending this information over and over again only to be ignored.

Sincerely,

Jody McCaffree
PO Box 1113
North Bend, OR 97459
[redacted]

From: Jody McCaffree
Sent: Monday, May 14, 2018 11:10 AM
To: 'Laura.M.Springer@uscg.mil'
Subject: Complaint - Request for LNG Hazard contact person

Dear Lt. Cmdr. Laura Springer:

I just read your announcement regarding the Coos Bay being suitable for the Jordan Cove LNG project. This should be shocking news to the general public. We would like to know what you did with the July 1, 2008 Coast Guard assessment and how without any real changes to the Coos Bay channel you now are ignoring your prior recommendations for safety and security? Why is the Coast Guard ignoring the gas industries SIGTTO recommendations for the safe siting of LNG facilities? Why are you ignoring the FAA's May 7, 2018 thirteen (13) determinations of *Presumed Airport Hazards* with respect to the Jordan Cove Project? The FAA determined Jordan Cove's ships are a hazard but the Coast Guard has not? Amazing! Why would you place so many school children in harm's way in the Coos Bay area? Why would you put our airport at such risk?

Your recent announcement states that the Coast Guard received official notification January 9, 2017. That is not exactly true and the Coast Guard should offer a retraction. This project has been in the works since 2004. Jordan Cove submitted a Letter of Intent, pursuant to 33 C.F.R. § 127.007, and a Waterway Suitability Assessment ("WSA") for its original LNG import project in April 2006. The U.S. Coast Guard ("USCG") issued a Water Suitability Report on July 1, 2008, and provided a Letter of Recommendation on April 24, 2009. On December 28, 2012, JCEP submitted an amended and updated Letter of Intent to the USCG for the prior export project proposal under Docket No. CP13-483. On August 5, 2016, the USCG accepted the annual 2015 review of the WSA update as an LNG export project. Jordan Cove submitted the 2016 annual update of the WSA to the USCG on November 23, 2016.

I did my best to try to talk with Coast Guard personnel at Jordan Cove's latest round of Open Houses held on Tuesday, March 21, 2017 at the Mill Casino in North Bend. It was obvious from those conversations that the current Coast Guard personnel were not interested in what I had to say and for the most part were pretty much clueless about LNG hazards.

I suggest you include the general public and non-biased LNG hazard experts in with your consultations before you decide whether something is safe or not. We do not need another New Carissa fiasco like the Coast Guard created in 1999. Only this time it would be far, far worse.

I would like to know who is in charge of LNG hazards for the Coast Guard and where I might be able to file an official complaint. As a cooperating agency with the FERC you should really be paying attention to what has been filed under the current FERC dockets for Jordan Cove (CP17-495-000; CP17-494-000; and PF17-4-000)

I have asked to be notified concerning these matters in the past but to date I have yet to receive any notifications from the Coast Guard.

Sincerely,

Jody McCaffree
PO Box 1113
North Bend, OR 97459
[redacted]

From: Jody McCaffree
Sent: Monday, November 20, 2017 11:46 AM
To: Brian Dunn/U.S. Coast Guard
Cc: Crowell, Ben W LCDR/U.S. Coast Guard
Subject: Connecting re Jordan Cove LNG Export Project

To: Brian Dunn United States Coast Guard [redacted]

Dear Mr. Dunn:

I came across your contact information in a letter that the Federal Energy Regulatory Commission (FERC) sent out on October 12, 2017 under Accession No. 20171012-3062. I do not know if you are the Coast Guard personnel responsible for overseeing the safety and security of the Jordan Cove LNG export project or not but I am passing along the following information sent on the 18th to Lieutenant Commander Crowell. These issues along with others are critical and must be thoroughly addressed with respect to the proposed Jordan Cove LNG export project before that project is allowed to proceed.

I look forward to discussing these and other important matters with you.

Sincerely.

Jody McCaffree
PO Box 1113
North Bend, OR 97459
[redacted]

From: Jody McCaffree
Sent: Saturday, November 18, 2017 11:23 AM
To: Crowell, Ben W LCDR/U.S. Coast Guard
Subject: Connecting re Jordan Cove Charleston Fire Station Meeting

Dear Lieutenant Commander Crowell:

I connected with you yesterday at the Jordan Cove Charleston Fire Station meeting and presentation.

At yesterday's presentation, Peter Schaedel, Jordan Cove's marine director from their Houston Office, stated that the Coast Guard would be handling all the safety and security for LNG transits in and out of the Coos Bay, including safety along the shoreline. Several things that Mr. Schaedel stated were not true and I would like to be in communication with the current contact in the Coast Guard who is handling all the safety and security for the proposed Jordan Cove LNG vessel transits. There are safety concerns that need to be addressed before Jordan Cove is given the green light in any way.

According to a September 9, 2003 CRS Report for Congress titled, "*Liquefied Natural Gas (LNG) Infrastructure Security: Background and Issues for Congress*,"[1] by Paul W. Parfomak, Specialist in Science and Technology Resources, Science, and Industry Division:

Page CRS-17:

> *...The Coast Guard Program Office estimates that it currently costs the Coast Guard approximately $40,000 to $50,000 to "shepherd" an LNG tanker through a delivery to the Everett terminal, depending on the duration of the delivery, the nature of the security escort, and other factors.*[2] ***<u>State and local authorities also incur costs for overtime police, fire and security personnel overseeing LNG tanker deliveries.</u> The state of Massachusetts and the cities of Boston and Chelsea estimated they spent a combined $37,500 to safeguard the first LNG shipment to Everett after September 11, 2001.***[3] ***Based on these figures, <u>the public cost of security for an LNG tanker shipment</u> to Everett is <u>on the order of $80,000, excluding costs incurred by the terminal owner</u>****...*

On July 1, 2008, the Coast Guard completed a review of the Waterway Suitability Assessment (WSA) for the Jordan Cove Energy Project and **determined that the Coos Bay was not**

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[1] http://www.au.af.mil/au/awc/awcgate/crs/rl32073.pdf
[2] U.S. Coast Guard, Program Office. Personal communication. August 12, 2003. This estimate is based on boat, staff and administrative costs for an assumed 20-hour mission
[3] McElhenny, John. "State Says LNG Tanker Security Cost $20,500." Associated Press. November 2, 2001. p1.

currently suitable, but could be made suitable for the type and frequency of LNG marine traffic associated with the LNG project. Coast Guard mitigation measures included **limiting the LNG carrier to the physical dimensions of a 148,000 m3 class vessel**. The ship dimension used in the study reflected an overall length of 950 feet and a beam of 150 feet with a loaded draft of 40 feet. (***See*** *WSA Report*)

The Coast guard determined that the channel must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed. The Coos Bay is only dredged to 37 feet currently. LNG ships would transit the bay during high slack tides, the same tides used by the fishing fleet.

The Coast Guard established a Safety/Security Zone for LNG vessels both while the vessel is moored and even when the vessel is not moored. When the LNG vessel is at the docking facility there would be a 150 yard security zone around the vessel to include the entire terminal slip and when there is no LNG vessel moored, the security zone would cover the entire terminal slip and extend 25-yards in the waterway. (CG-WSA page 2) In addition, the Coast Guard has also set a moving safety/security zone for the LNG tanker ship that extends 500-yards around the vessel but ends at the shoreline. **No vessel may enter the safety / security zone without first obtaining permission from the Coast Guard Captain of the Port.** [4] <u>This safety and security zone would encompass the entire bay in some areas</u>.

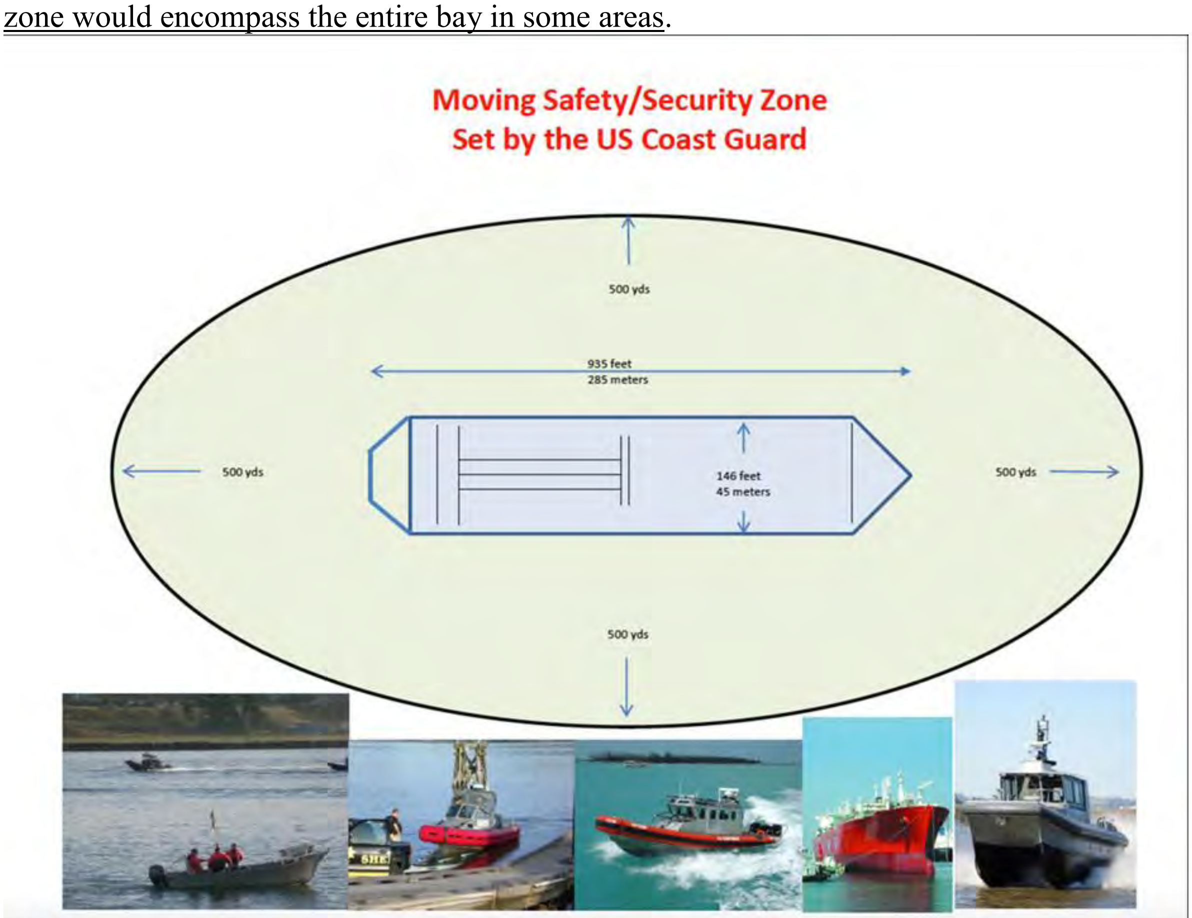

Diagram above from Jordan Cove March 2012 Open House

[4] Coast Guard - LOR / WSR / WSA for Port of Coos Bay / Jordan Cove Energy Project: https://homeport.uscg.mil/mycg/portal/ep/contentView.do?contentTypeId=2&contentId=63626&programId=12590&%20pageTypeId=16440&BV

JORDAN COVE LNG EXPORT VOLUMES

The proposed Jordan Cove Energy Project applied (Sept 21, 2017) to the Federal Energy Regulatory Commission (FERC) to export 7.8 million metric tons of LNG. This amounts to around 1 Bcf/d of exported natural gas.

However, Jordan Cove has publicly stated that they plan on increasing that volume to 9 million metric tons of LNG. This amounts to around 1.2 Bcf/d of exported natural gas.

Jordan Cove has approvals from the Canadian National Energy Board (NEB) to "export" 1.55 Bcf/d of natural gas and from the U.S. Dept of Energy (DOE) to "import" this volume from Canada.

Even though the U.S DOE has approved Jordan Cove importing 1.55 Bcf/d of gas from Canada (11.6 million metric tons LNG per year), the U.S. DOE has **only given Jordan Cove permission to export 1.2 Bcf/d of gas to Free Trade Agreement Nations (9 million metric tons LNG per year)** and .8 Bcf/d of that 1.2 Bcf/d has been approved to go to Non-Free Trade agreement nations IF JORDAN COVE IS ABLE TO COMPLY WITH ALL THE CONDITIONAL REQUIREMENTS FOUND IN DOE ORDER 3413. So far that has not happened, so they don't have approval yet to export to Non-Free Trade Agreement Nations.

Below is how this volume of LNG being exported from Coos Bay calculates out with respect to potential harbor shipping disruptions.

Jordan Cove states in their Resource Report #1 Page 13:

> *The number of ship calls at the LNG vessel berth* ***has increased to 110 to 120. This number was previously 90 to 100****.*

Once again, Jordan Cove has deliberately underestimated their LNG shipping impacts. See calculations below:

Calculating 148,000 cubic meter LNG ship at –
600 to 1 conversion from Natural Gas and determining how many shipments that would mean is below:

148,000 cubic meters LNG ship = 5,226,570.675 cubic feet of LNG

5,226,570.675 X **600** = 3,135,942,405 cubic feet of natural gas per shipment

7.8 million metric tons of LNG yearly = 379.86 billion cubic feet of NG (7.8 X 48.7)
(1 million metric tons LNG = 48.7 billion cubic feet NG
(https://www.extension.iastate.edu/agdm/wholefarm/html/c6-89.html)

379,860,000,000 cubic feet of gas yearly shipped by JCEP :/: 3,135,942,405 cubic feet of gas per shipload = **121 shipments needed per year which = 242 harbor disruptions at high slack tide**

due to shipping impacts involving the LNG vessel both coming in and going out of the harbor.

----

9 million metric tons of LNG yearly = 438.3 billion cubic feet of NG (9 X 48.7)
(1 million metric tons LNG = 48.7 billion cubic feet NG
(https://www.extension.iastate.edu/agdm/wholefarm/html/c6-89.html)

438,300,000,000 cubic feet of gas yearly shipped by JCEP :/: 3,135,942,405 cubic feet of gas per shipload = **139.76 shipments needed per year which = 279.52 harbor disruptions at high slack tide due to shipping impacts involving the LNG vessel both coming in and going out of the harbor.**

This is considerably higher than Jordan Cove's 110 to 120 shipments that are stated in their recent Resource Report #1 (page 13) that has been filed with the FERC.

If Jordan Cove was to export the entire 1.55 Bcf/d of LNG from Canada it would amount to the following harbor disruptions.

1.55 Bcf/d X 365 days in a year = 565.75 Bcf/year of exported gas

565,750,000,000 cubic feet of gas yearly shipped by JCEP :/: 3,135,942,405 cubic feet of gas per shipload = **180 shipments needed per year which = 360 harbor disruptions at high slack tide due to shipping impacts involving the LNG vessel both coming in and going out of the harbor.**

SAFETY GUIDELINES

One of the reasons there is such as good safety record involving LNG Carriers worldwide is due to the fact that the current Ports in operation have developed their docking facilities for these LNG terminals strictly following the guidelines laid out by the *Society of International Gas Tanker & Terminal Operators* (SIGTTO)[5].

Examples of SIGTTO guidelines not addressed adequately include:

1) **Approach Channels. Harbor channels should be of uniform cross-sectional depth and have a minimum width, <u>equal to five time the beam of the largest ship</u>**
2) **Turning Circles. <u>Turning circles should have a minimum diameter of twice the overall length of the largest ship</u>, where current effect is minimal. Where turning circles are located in areas of current, diameters should be increased by the anticipated drift.**
3) **Tug Power. Available tug power, expressed in terms of effective bollard pull, should be sufficient to overcome the maximum wind force generated on the largest ship using the terminal, under the maximum wind speed**

[5] **Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14 -** Published by *Society of International Gas Tanker $ Terminal Operators Ltd* / 1997

permitted for harbor maneuvers and with the LNG carrier's engines out of action.

4) **Site selection process should remove as many risks as possible by placing LNG terminals in <u>sheltered locations remote from other port users</u>. Suggest port designers construct jetties handling hazardous cargoes in remote areas where ships do not pose a (collision) risk and <u>where any gas escaped cannot affect local populations.</u> Site selection should limit the risk of ship strikings, limiting interactive effects from passing ships and reducing the risk of dynamic wave forces within mooring lines.**
5) **<u>Building the LNG terminal on the outside of a river bend is considered unsuitable</u> due to fact that a passing ship may strike the berthed carrier if the maneuver is not properly executed.**
6) **SIGTTO Examples given for reducing risk factors beyond normal operations of ship/shore interface include LNG terminal patrols of the perimeter of the offshore safety zones with guard boats and to <u>declare the air-space over an LNG terminal as being a restricted zone where no aircraft is allowed to fly</u> without written permission.**
7) **Restriction of the speed of large ships passing close to berthed LNG carriers.**

Also some of the safety guideline preventative measures found in the Sandi National Laboratories Report – "*Guidance on Risk Analysis and Safety Implications of Large Liquefied Natural Gas (LNG) Spill Over Water*" – Dec 04:

Guidelines (Pg 64) include: [6]

1) Appropriate off-shore LNG ship interdiction and inspections for explosives, hazardous materials, and proper operation of safety systems;
2) Appropriate monitoring and control of LNG ships when entering U.S. waters and **protection of harbor pilots and crews**;
3) **Enhanced safety zones around LNG vessels (safety halo) <u>that can be enforced</u>;**
4) **<u>Appropriate control of airspace over LNG ships</u>**; and
5) **Appropriate inspection and protection of terminal areas, tug operations prior to delivery and unloading operations.**

On January 14, 2015, and February 6, 2015, Jerry Havens, Distinguished Professor of Chemical Engineering at University of Arkansas, and James Venart, Professor Emeritus of Mechanical Engineering at University of New Brunswick, published two papers regarding the Jordan Cove LNG Export Terminal Draft Environmental Impact Statement under FERC Docket No. CP13-483. **Professor Havens and Professor Venart found significant discrepancies and problems with Jordan Cove's hazard analysis for their LNG Export facility and determined the hazards had been significantly underestimated.** Safety measures incorporated into the proposed Jordan Cove former LNG Export terminal actually increased the chance of a catastrophic failure and presented a far more serious public safety hazard than regulators had

[6] Without an emergency response plan to review it is hard to know if some of these recommendations have been met. At the FERC hearing held in Coos Bay on December 8, 2014, U.S. Coast Guard Captain of the Port stated that the Coast Guard has "***no intention to close the waterway during LNG shipments.***"

analyzed and deemed acceptable. Adding liquefaction equipment to proposed LNG Import terminals increases the hazard risks of these facilities as these documents explain.

Copies of 1-14-2015 and 2-6-2015 filings submitted to FERC by Professor Havens and Professor Venart can be linked to here:

- 1-14-2015 - Jerry Havens Ph.D and James Venart Ph.D under CP13-483 http://elibraryFERC.gov/idmws/file_list.asp?accession_num=20150114-5038
- 2-6-2015 - Supplementary Comment with Questions by Jerry Havens Ph.D and James Venart Ph.D under CP13-483. http://elibraryFERC.gov/idmws/file_list.asp?accession_num=20150206-5040

I have provided links below to some of the publications that these two professors have published. These are high level professionals in the area of Chemical Engineering and Chemical Hazards, just in case you may not be familiar with their work.

> **Published Research work of Jerry Havens University of Arkansas - Department of Engineering**
> http://www.researchgate.net/profile/Jerry_Havens
>
> **Published Research work of James E.S. Venart - University of New Brunswick - Department of Mechanical Engineering**
> http://www.researchgate.net/profile/James_Venart

In their Feb 6, 2015, filing to the FERC, Professor Havens and Professor Venart asked specific questions of the FERC. **THOSE QUESTIONS HAVE YET TO BE ANSWERED.** The FERC, the U.S. Department of Transportation and the Coast Guard need to make sure those questions are answered adequately and scientifically. Thousands of people living in the Coos Bay area depend on it.

LNG VESSEL HAZARDS

It is all spelled out in the scientific literature that if a LNG tanker ship was to be breached and only 1/2 of one of the (4 to 5) LNG tanks (or 3 to 4 million gallons of LNG) was to leak out into the water and a pool fire was to develop, people up to a mile away would be at risk of receiving 2nd degree burns in 30 seconds. **This is because heat flux levels of 5kW/m2 would go out as far as a mile away from the fire.** If the Jordan Cove LNG Export Project was to actually make it through permitting and be built, 16,922 people would live in the Jordan Cove LNG hazard zones of concern according to the Jordan Cove former Import FERC EIS (Page 4.7-3) and also the former Export Draft EIS (Page 4-980). The former Jordan Cove LNG Export Draft EIS page 4-7 states:

> *The waterway for LNG vessel marine traffic would traverse 7.5 miles of the existing navigation channel within Coos Bay. The navigation channel is zoned "Deep-Draft Navigation Channel." in the CBEMP. The navigation channel, which is generally 300-feet-wide and 37-feet-deep, is maintained by the COE on behalf of the Port.*

LNG tankers with up to a 40 foot draft would exit our narrow Bay carrying around 39 million gallons of LNG but there is little concern given for our safety by local officials. Both the cities of North Bend and Coos Bay have signed agreements indemnifying Jordan Cove should there be an LNG accident. The City of North Bend has also passed a Resolution and written letters of support for the Project prior to the completion of the NEPA process and also prior to Final Decisions being made on Jordan Cove's Land Use Permits. Coos County Commissioner John Sweet has also done the same.

Jordan Cove's FERC former Draft Export EIS Page 2-76 states:

> *LNG to be exported from the Jordan Cove terminal to overseas markets would be transported in vessels specially designed and built for that task. Jordan Cove expects that its terminal would be visited by about 90 LNG vessels per year. These vessels would be loaded with LNG at the terminal and deliver the cargo to customers, most likely around the Pacific Rim.* ***LNG vessels would be under the ownership and control of third-parties, not Jordan Cove****, and* ***would not be regulated by the FERC.*** (Emphasis added)

This is not acceptable as it places our entire area at an extreme hazard risk and liability.

Structures close to an LNG pool fire, should one develop, could actually self-ignite from the high heat flux levels. This is not my words but comes directly from the December 2004 Sandia Report, **"*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*."** [7] The large hazardous burn zones associated with these LNG faculties are also confirmed by other Government and independent studies as well. [8] In 2005 the Port of Long Beach and the California Public Utilities Commission had an analysis done entitled, "*An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach.*" [9] The analysis resulted in the Port of Long Beach no longer approving the proposed LNG facility.

LNG tankers would transit only 6/10ths of a mile from children attending Sunset and Madison schools. The tankers and cargo ships would transit within 1,350 feet of the shoreline areas of the community of Empire, 2,150 feet of the shoreline areas of the community of Barview, 1,900 to 2,300 feet of the Charleston breakwater, and 2,100 to 3,100 feet of the North Bend Airport. This is well within the LNG hazard zone distances that have been established by the many government and scientific reports.

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[7] "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water.*"

[8] United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; "*Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf
U.S. Department of Energy report to Congress, "*Liquefied Natural Gas Safety Research*" ; May 2012 : http://energy.gov/sites/prod/files/2013/03/f0/DOE_LNG_Safety_Research_Report_To_Congre.pdf [NOTE: Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from a large LNG pool fire will decrease by at least 2 to 7 percent compared to results obtained from previous studies. In spite of this slight decrease, people up to a mile away are still at risk of receiving 2nd degree burns in 30 seconds should a LNG pool fire develop due to a medium to large scale LNG breach event.

[9] *"An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach"* By Dr. Jerry Havens, September 14, 2005 - http://www.ecosakh.ru/data/im_docs_62_ocenka_ugroz_v_svyazi_s_razmescheniem_SPG%28angl.yaz.%29.pdf

I am sure the Coast Guard is well aware of these hazard issues, but as resident who would be living in one of these proposed LNG hazard zones, I wanted to confirm this and encourage the Coast Guard to take ALL the measures that are absolutely necessary to ensure our safety. Our tax dollars should not have to pay for these proposed safety measures either. This should be Jordan Cove's responsibility.

Sincerely,

Jody McCaffree
Po Box 1113
North Bend, OR 97459
[redacted]

REFERENCES

[1]http://www.au.af.mil/au/awc/awcgate/crs/rl32073.pdf
2 U.S. Coast Guard, Program Office. Personal communication. August 12, 2003. This estimate is based on boat, staff and administrative costs for an assumed 20-hour mission
3 McElhenny, John. "State Says LNG Tanker Security Cost $20,500." Associated Press. November 2, 2001. p1.
4 Coast Guard - LOR / WSR / WSA for Port of Coos Bay / Jordan Cove Energy Project: https://homeport.uscg.mil/mycg/portal/ep/contentView.do?contentTypeId=2&contentId=63626&programId=12590&%20pageTypeId=16440&BV
[5] **Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14 -** Published by *Society of International Gas Tanker $ Terminal Operators Ltd* / 1997
[6] Without an emergency response plan to review it is hard to know if some of these recommendations have been met. At the FERC hearing held in Coos Bay on December 8, 2014, U.S. Coast Guard Captain of the Port stated that the Coast Guard has "***no intention to close the waterway during LNG shipments.***"
[7] "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water.*"
[8] United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; "*Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf
U.S. Department of Energy report to Congress, "*Liquefied Natural Gas Safety Research*" ; May 2012 : http://energy.gov/sites/prod/files/2013/03/f0/DOE_LNG_Safety_Research_Report_To_Congre.pdf [NOTE: Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from a large LNG pool fire will decrease by at least 2 to 7 percent compared to results obtained from previous studies. In spite of this slight decrease, people up to a mile away are still at risk of receiving 2nd degree burns in 30 seconds should a LNG pool fire develop due to a medium to large scale LNG breach event.
[9] *"An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach"* By Dr. Jerry Havens, September 14, 2005 - http://www.ecosakh.ru/data/im_docs_62_ocenka_ugroz_v_svyazi_s_razmescheniem_SPG%28angl.yaz.%29.pdf

Jordan Cove LNG Tanker Hazard Zones (FEIS Page 4.7-3)

Zone 1 (yellow) - No one is expected to survive in this zone. Structures will self ignite just from the heat.
Zone 2 (green) - People will be at risk of receiving 2nd degree burns in 30 seconds on exposed skin in this zone.
Zone 3 (blue) - People are still at risk of burns if they don't seek shelter but exposure time is longer than in Zone 2.
Map does not include the hazard zones for the South Dunes Power Plant and the Pacific Connector Gas Pipeline.

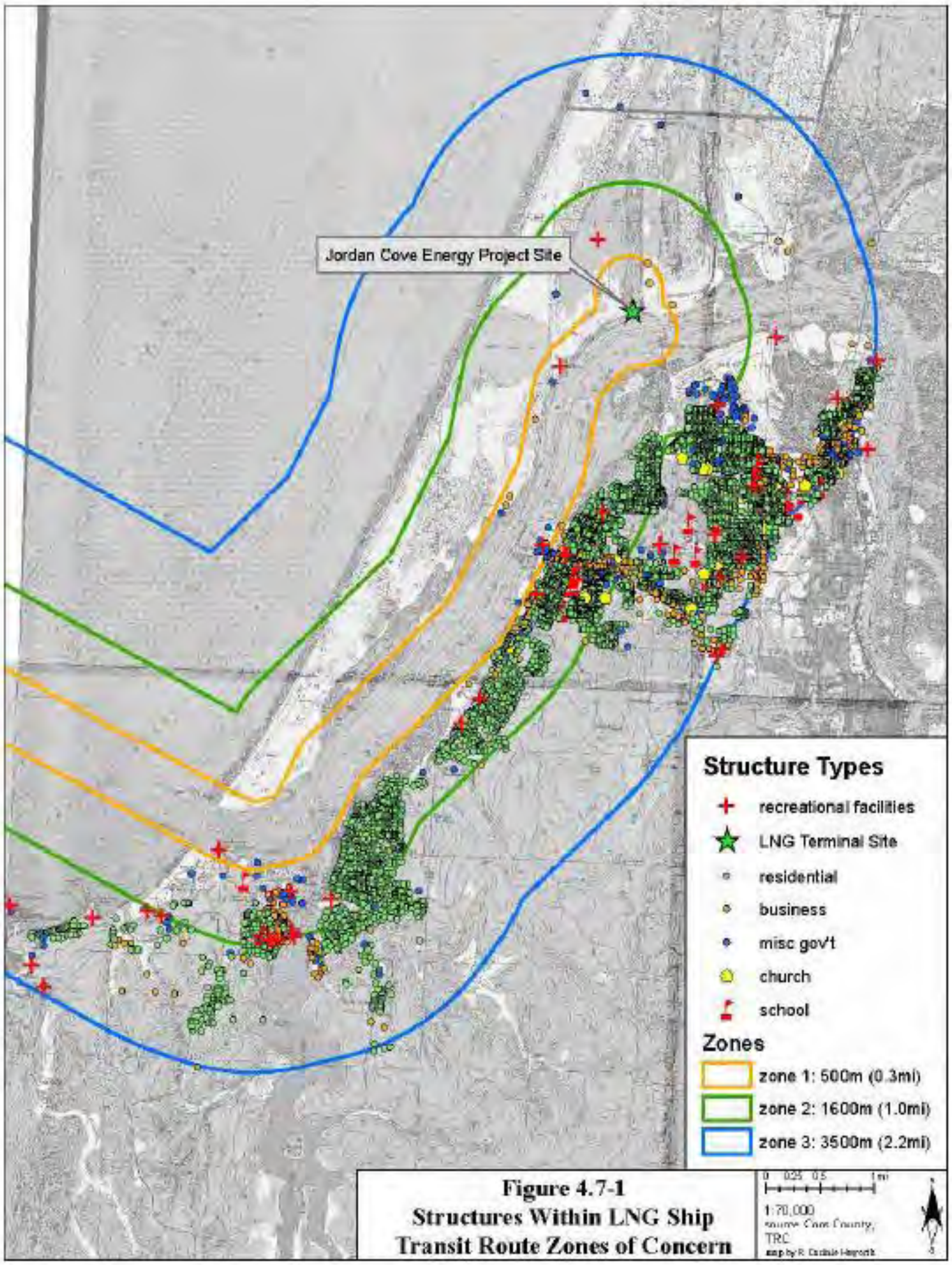

Figure 4.7-1
Structures Within LNG Ship Transit Route Zones of Concern

NATURAL GAS:

Explosive LNG issues grab PHMSA's attention

Jenny Mandel, E&E reporter

EnergyWire: Tuesday, June 7, 2016

Smoke pours from petroleum storage tanks following a 2009 explosion at the Caribbean Petroleum Corp. refinery in San Juan, Puerto Rico. The blast and fire damaged 17 of the 48 tanks at the site, and flames burned for nearly 60 hours. Photo courtesy of the U.S. Chemical Safety and Hazard Investigation Board.

The Department of Transportation's May 19 workshop on liquefied natural gas (LNG) safety started with a bang.

At DOT's headquarters in Washington, D.C., the agency's Pipeline and Hazardous Materials Safety Administration (PHMSA) hosted an in-depth discussion of what went wrong during a March 2014 explosion at an LNG facility in Plymouth, Wash., that led to five injuries and $72 million in property damage (EnergyWire, May 6).

The decision by PHMSA to conduct a broad review of its LNG safety rules -- and kick it off with an unusually open discussion of a fiery accident -- suggests the agency has taken to heart the saltiest criticisms tossed from Capitol Hill. "PHMSA is not only a toothless tiger, but one that has overdosed on Quaaludes and is passed out on the job," Rep. Jackie Speier, a Democrat from San Francisco, said during a congressional hearing in April 2015.

She pointed to the lethal and destructive natural gas pipeline accident in San Bruno, Calif., in 2010. In its aftermath, PHMSA came under fire for being slow to update its safety regulations. Late last year, a leaking Aliso Canyon underground gas storage facility outside Los Angeles, operated by Southern California Gas Co., prompted hand-wringing that regulators were underprepared.

If gas pipelines and storage fields come with risk, researchers are increasingly concerned that the expanding footprint of big LNG export terminals and other facilities along the U.S. coast are also potentially deadly.

LNG is jam-packed with energy. Natural gas is turned into a liquid by supercooling it to minus 260 degrees Fahrenheit, which shrinks its volume 600-fold and makes it easier to transport across the ocean.

Natural gas and its liquid form are flammable and explosive in confined spaces, but researchers say it's not prone to exploding when released in large, open areas. That's not the case for other heavy hydrocarbons such as propane and ethane, which can be stored at large LNG export facilities.

The concern among researchers and regulators grappling with how to regulate LNG safety is the potentially deadly mix of liquid fuels at an LNG site.

Things that go boom

At the DOT workshop last month, a presentation by Graham Atkinson, a principal scientist in the Major Hazards Unit of the Health and Safety Lab in Buxton, England, focused on what happens when heavy hydrocarbons explode.

explode.

The audience listened, riveted, as Atkinson showed photos -- some not previously seen by the public -- from industrial accidents linked to liquefied petroleum gas (LPG), LNG, gasoline and other petrochemicals.

Four of the incidents took place within the last decade and were explosions of so-called unconfined vapor clouds that led to a series of cascading events that ultimately destroyed the facilities.

Researchers looked at 24 vapor cloud explosions but focused their attention on four major industrial accidents -- at gasoline storage sites in Buncefield, England, in 2005; Jaipur, India, in 2009; San Juan, Puerto Rico, in 2009; and at an LPG storage site at Venezuela's Amuay refinery in 2012.

In work funded by PHMSA through a contract with the Energy Department's Oak Ridge National Laboratory, Atkinson's team reviewed photos and videos from the accidents and conducted tests with gasoline in a range of spill conditions. The team focused on how vapor clouds form in low wind conditions and when barriers keep gases from fully dispersing.

Atkinson said an accident can happen under two conditions. One is a small leak that, after as little as 15 minutes with no wind, can cause a massive explosion that resembles a bomb blast with no epicenter. Devastation is spread evenly across the range of the vapor cloud.

An unconfined vapor cloud explosion at a gasoline storage site in Buncefield, England, in 2005 left bomblike devastation across a wide area. Photo courtesy of the U.K. Health and Safety Laboratory.

The other accident scenario is a large leak on a windy day, when cloud dispersion from the wind cannot keep up with the volume of gas released. That, too, creates a cloud-sized explosion zone. The shape of the plume can be mapped from the destruction.

Pictures from San Juan, Buncefield, Amuay and Jaipur show cars twisted and burned, bombed-out buildings, and flaming storage tanks.

"Fuel tanks are efficiently set on fire in the area covered by the vapor cloud," Atkinson noted, estimating that 95 percent of tanks exposed to the vapor clouds were set on fire. "It means it's a real tough job for all the emergency services. They're dealing with [potentially] 20 tanks set on fire. It's an almost unmanageable situation."

The researchers also looked at cases in which flash fires turned into explosions, finding that in some cases a confined space or a congested intersection of piping turned a fire into a blast.

"In all but one of the incidents reviewed, when a very large cloud was formed, there was a severe explosion," Atkinson said.

In low wind conditions, vapor clouds that accumulated from small, sustained leaks caused blast damage and fatalities 765 yards -- nearly half a mile -- or more from the source.

And if a large cloud of gasoline or LPG accumulates, a "severe explosion" is likely, Atkinson said.

'20 minutes'

After Atkinson spoke, a leader in the LNG industry quickly tried to wrestle control of the discussion, emphasizing that LNG doesn't carry the same risks as the non-methane fuels he had focused on.

Cheniere Energy Inc. is developing the Sabine Pass LNG export terminal in Cameron Parish, La. The terminal already has one processing train up and running to liquefy LNG, and construction plans include four more; the plant is the first modern LNG export facility in the United States (EnergyWire, May 3).

Pat Outtrim, vice president of government affairs for Cheniere, questioned Atkinson on his presentation in a rapid-fire series of yes-or-no questions.

Atkinson agreed with Outtrim that the heavy hydrocarbons tested have different properties from methane, and that the alert and emergency shutdown equipment at the facilities studied were absent, nonfunctioning or not able to alert the right people quickly.

But he disagreed with the notion that his results aren't applicable to LNG facilities.

Ethane blends, propane, isobutane and ethylene, as well as hundreds of metric tons of condensates like pentanes and hexanes, might be present at an LNG export site. The explosion research "shows just how important the detection and response protocols are," Atkinson told Outtrim. Vapor cloud explosions like those demonstrated "can't happen at an LNG facility if you detect [a leak] early and shut it down right away," he said.

The takeaway for the LNG industry should include consideration of automatic equipment shut-offs, Atkinson told EnergyWire.

"Twenty minutes can be enough to cause a problem," he said. If equipment shut-offs are manual, the staff needs to be well-trained. If sensors indicate a leak, "the response can't be, 'Oh, I need to go tighten it up.'"

"Problems tend to come from people. There are just so many cases where [warning lights] start flashing and people just go to pieces," he said.

One more challenge? Explosion events often occur at night, when wind speeds slow as the air cools. So plant personnel can go from keeping watch over a sleepy facility in the small, dark hours to a rapidly evolving emergency.

"When they decide what's sensible to automate, they ought to think about these factors and take it into account," Atkinson said.

The new LNG era

Still, automated controls are probably not the big worry that set PHMSA down the path of researching old accidents -- especially since many of a plant's most important controls have physical fail-safe mechanisms in case the electronics fail.

So why did PHMSA dedicate so much time to discussion of the hazards tied to gasoline, LPG and other hydrocarbons that are afterthoughts at most LNG installations?

A critique by two longtime LNG researchers offers some insight.

Jerry Havens and James Venart submitted public comments to the Federal Energy Regulatory Commission in January 2015 on a proposal to build the Jordan Cove LNG terminal in Coos Bay, Ore.

A 2009 vapor cloud explosion and ensuing fire at an Indian Oil Corp. facility in Jaipur, India, destroyed the plant and damaged homes more than a mile away, according to an investigation report. Photo courtesy of the U.K. Health and Safety Laboratory.

Havens has worked on LNG safety issues throughout his 40-year career and authored two of the computer models whose use was long required by federal regulators to assess the hazards of proposed LNG facilities. Venart was the longtime director of the Fire Science Centre at the University of New Brunswick in Canada, and studied industrial heat exchange and catastrophic explosions.

The Jordan Cove project proposed a liquefaction plant capable of processing up to 6.8 million metric tons per year of natural gas.

Havens and Venart said they were concerned that regulations governing LNG import terminals had been guided by the premise that LNG, as methane, poses less danger than other gas liquids and petroleum fuels. But with LNG export terminals designed and constructed under regulations used for simpler LNG import facilities, Havens and Venart warned that regulators were overlooking dangers.

"We believe the [Jordan Cove draft environmental impact statement] fails to provide for protection of the public from credible fire and explosion hazards," the researchers said.

The mix of refrigerants used to chill the gas and the heavy hydrocarbon impurities in pipeline gas that are stripped out and stored on-site pose a threat, they said.

"We believe these additional hazards have been discounted without sufficient scientific justification in spite of multiple international reports during the last decade of catastrophic accidents involving unconfined hydrocarbon vapor cloud explosions," Havens and Venart said.

The researchers also raised concerns that Jordan Cove and other proposed facilities would use concrete "vapor walls" to trap a gas cloud on the property and keep the fire hazards from breaching the property lines. But such walls would cause methane and other gases to build up into concentrated vapor clouds several meters deep, increasing the explosion risk.

With densely packed processing equipment on the site and a vapor fence trapping hydrocarbons, "one could hardly design the releases to better maximize the potential for catastrophic explosion hazard," Havens and Venart added.

FERC finalized Jordan Cove's EIS in September. It made no mention of Havens and Venart's comments.

Michael Hinrichs, a spokesman for the Jordan Cove project, noted in an email that "dispersion modeling, safety and security were all thoroughly analyzed and accepted by the FERC, [the Department of Transportation] and PHMSA to be within compliance." The three agencies, he said, "have all upheld the current modeling as meeting the safety criteria for the industry."

The Jordan Cove project's fate has since been thrown up in the air by an unexpected FERC decision to reject the project despite the favorable review by agency staff, pointing to a lack of firm contracts for LNG off-take (EnergyWire, April 19).

But Havens continues to be concerned. In a paper at the Health and Safety Laboratory -- where researcher Atkinson works -- in April, he argued that regulators are "doing it wrong" when it comes to gauging the explosion hazards of large hydrocarbon clouds.

Havens said PHMSA may be relying on the wrong computer models to assess explosion risks. Most of its results are classified for security reasons.

Divided responsibilities

At the workshop in May, Kenneth Lee, who directs PHMSA's engineering and research division within the Office of Pipeline Safety, declined to say what specific regulatory changes are on the table for an upcoming overhaul of the LNG rulebook, or even what the key questions are, deferring to public input from the meeting to shape the process (EnergyWire, May 20).

But the workshop itself, in providing a platform to discuss heavy hydrocarbon risks, points to the potential for new requirements for LNG export facilities. How those requirements might be designed remains to be seen.

Industry has welcomed small tweaks to PHMSA's rules that would bring them up to date, more easily encompass new technologies and be more in line with standards used by regulators in other jurisdictions. But any changes that added new hurdles to the process of siting LNG facilities -- which primarily falls under FERC jurisdiction -- could face opposition from developers. They could raise difficult questions about Sabine Pass LNG and the four other LNG export terminals under construction.

For its part, PHMSA pledges that the coming rulemaking process will be transparent. "We take comments that you submit very seriously," said Julie Halliday, a member of the agency's engineering and research division who coordinated much of the meeting, in a discussion of the next steps. "We will address those points that you submit."

Still, she noted that PHMSA's authority over LNG facility siting is limited. "We don't actually have authority for siting within our regulations," she said, describing the agency's role in that process as working out the public safety "exclusion zones" that extend around the core of the facility.

"It's about a setback. It's not telling you whether you can site a facility at a certain location," she added, noting that other agencies control that question. "If FERC doesn't have jurisdiction to site a facility, it's the local jurisdiction."

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Exhibit 5

United States Government Accountability Office

GAO

Report to Congressional Requesters

February 2007

MARITIME SECURITY

Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification

G A O
Accountability * Integrity * Reliability

GAO-07-316

GAO Accountability•Integrity•Reliability

Highlights

Highlights of GAO-07-316, a report to congressional requesters

February 2007

MARITIME SECURITY

Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification

Why GAO Did This Study

The United States imports natural gas by pipeline from Canada and by tanker as liquefied natural gas (LNG) from overseas. LNG—a supercooled form of natural gas—currently accounts for about 3 percent of total U.S. natural gas supply, with an expected increase to about 17 percent by 2030, according to the Department of Energy (DOE). With this projected increase, many more LNG import terminals have been proposed. However, concerns have been raised about whether LNG tankers could become terrorist targets, causing the LNG cargo to spill and catch on fire, and potentially explode. DOE has recently funded a study to consider these effects; completion is expected in 2008.

GAO was asked to (1) describe the results of recent studies on the consequences of an LNG spill and (2) identify the areas of agreement and disagreement among experts concerning the consequences of a terrorist attack on an LNG tanker. To address these objectives, GAO, among other things, convened an expert panel to discuss the consequences of an attack on an LNG tanker.

What GAO Recommends

GAO recommends that the Secretary of Energy ensure that DOE incorporates into its LNG study the key issues identified by the expert panel.

In reviewing our draft report, DOE agreed with our recommendation.

www.gao.gov/cgi-bin/getrpt?GAO-07-316.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells at (202) 512-3841 or wellsj@gao.gov.

What GAO Found

The six unclassified completed studies GAO reviewed examined the effect of a fire resulting from an LNG spill but produced varying results; some studies also examined other potential hazards of a large LNG spill. The studies' conclusions about the distance at which 30 seconds of exposure to the heat (heat hazard) could burn people ranged from less than 1/3 of a mile to about 1-1/4 miles. Sandia National Laboratories (Sandia) conducted one of the studies and concluded, based on its analysis of multiple attack scenarios, that a good estimate of the heat hazard distance would be about 1 mile. Federal agencies use this conclusion to assess proposals for new LNG import terminals. The variations among the studies occurred because researchers had to make modeling assumptions since there are no data for large LNG spills, either from accidental spills or spill experiments. These assumptions involved the size of the hole in the tanker; the volume of the LNG spilled; and environmental conditions, such as wind and waves. The three studies that considered LNG explosions concluded explosions were unlikely unless the LNG vapors were in a confined space. Only the Sandia study examined the potential for sequential failure of LNG cargo tanks (cascading failure) and concluded that up to three of the ship's five tanks could be involved in such an event and that this number of tanks would increase the duration of the LNG fire.

GAO's expert panel generally agreed on the public safety impact of an LNG spill, but believed further study was needed to clarify the extent of these effects, and suggested priorities for this additional research. Experts agreed that the most likely public safety impact of an LNG spill is the heat hazard of a fire and that explosions are not likely to occur in the wake of an LNG spill. However, experts disagreed on the specific heat hazard and cascading failure conclusions reached by the Sandia study. DOE's recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel. The leading unaddressed priority the panel cited was the potential for cascading failure of LNG tanks.

LNG Tanker Passing Downtown Boston on Its Way to Port

Source: GAO.

Exhibit 6

U.S. DEPARTMENT OF ENERGY

Liquefied Natural Gas Safety Research

Report to Congress
May 2012

United States Department of Energy
Washington, DC 20585

Message from the Assistant Secretary for Fossil Energy

The Explanatory Statement accompanying the Consolidated Appropriations Act, 2008[1] and the House Report on the House of Representatives version of the related bill[2] requested the Department of Energy to submit a report to Congress addressing several key liquefied natural gas (LNG) research priorities. These issues are identified in the February 2007 Government Accountability Office Report (GAO Report 07-316), *Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*.

In response to this request, the Department of Energy tasked Sandia National Laboratories (SNL) with expanding the scope of the Department's LNG safety research program to address the research priorities identified in GAO Report 07-316. To accomplish this, SNL performed LNG field research and testing and conducted advanced computational modeling, simulation, and analyses over a three year period from May 2008 through May 2011. This report contains the findings, results, and conclusions of this research.

I am pleased to submit the enclosed report entitled, *Liquefied Natural Gas Safety Research Report to Congress*. The report was prepared by the Department of Energy's Office of Fossil Energy and summarizes the progress being made in this important area of research. This report is being provided to the following Members of Congress:

- **The Honorable Joseph R. Biden, Jr.**
  President of the Senate

- **The Honorable John Boehner**
  Speaker of the House of Representatives

- **The Honorable Daniel K. Inouye**
  Chairman, Senate Committee on Appropriations

- **The Honorable Thad Cochran**
  Vice Chairman, Senate Committee on Appropriations

- **The Honorable Dianne Feinstein**
  Chairman, Senate Subcommittee on Energy and Water Development
  Committee on Appropriations

- **The Honorable Lamar Alexander**

[1] Explanatory Statement accompanying Public Law 110-161 (Dec. 26, 2007) at page 570.
[2] H.Rept. 110-185 accompanying Energy and Water Development Appropriations Bill, 2008 (H.R. 2641) at page 73.

Ranking Member, Senate Subcommittee on Energy and Water Development
Committee on Appropriations

- **The Honorable Harold Rogers**
  Chairman, House Committee on Appropriations

- **The Honorable Norm Dicks**
  Ranking Member, House Committee on Appropriations

- **The Honorable Rodney P. Frelinghuysen**
  Chairman, House Subcommittee on Energy and Water Development
  Committee on Appropriations

- **The Honorable Pete Visclosky**
  Ranking Member, House Subcommittee on Energy and Water Development
  Committee on Appropriations

If you need additional information, please contact me or Mr. Jeff Lane, Assistant Secretary, Office of Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Charles D. McConnell

Executive Summary

The February 2007 Government Accountability Office Report (GAO Report 07-316), *Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*, identified several key Liquefied Natural Gas (LNG) research priorities highlighted by a GAO-convened panel of experts on LNG safety in order to provide the most comprehensive and accurate information for assessing the public safety risks posed by LNG tankers transiting to LNG facilities. To address these issues, Congress provided funding to the Department of Energy (DOE) to expand their LNG safety research program to focus on the major LNG research priorities contained in the GAO report. Sandia National Laboratories (SNL) supported the DOE in this effort starting May 2008 through May 2011 by conducting a series of large-scale LNG fire and cryogenic damage tests, as well as detailed, high performance computer models and simulations of LNG vessel damage resulting from large LNG spills and fires on water.

The key findings from these efforts include the following:

- For the large breach and spill events considered, as much as 40 percent of the LNG spilled from the LNG vessel's cargo tank is likely to remain within an LNG vessel's structure, leading to extensive cryogenic fracturing and damage to the LNG vessel's structural steel. In addition to the cryogenic damage, the heat fluxes expected from an LNG pool fire would severely degrade the structural strength of the inner and outer hulls of an LNG vessel. The extent of the cryogenic and fire damage on an LNG vessel resulting from large spills and associated pool fires would significantly impact the LNG vessel's structural integrity, causing the vessel to be disabled, severely damaged, and at risk of sinking.
- Current LNG vessel and cargo tank design, materials, and construction practices are such that simultaneous, multi-cargo tank cascading damage spill scenarios are extremely unlikely, though sequential multi-cargo tank cascading damage spill scenarios may be possible. Should sequential cargo tank spills occur, they are not expected to increase the hazard distances resulting from an initial spill and pool fire; however, they could increase the duration of the fire hazards.
- Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from large LNG pool fires will decrease by at least two to seven percent compared to results obtained from previous studies.
- Risk management strategies to reduce potential LNG vessel vulnerability and damage from breach events that can result in large spills and fires should be considered for implementation as a means to eliminate or reduce both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterways commerce. Approaches to be considered should include implementation of enhanced operational security measures, review of port operational contingency plans, review of emergency response coordination and procedures, and review of LNG vessel design, equipment and operational protocols for improved fire protection.

LIQUEFIED NATURAL GAS SAFETY RESEARCH

Table of Contents

I. Legislative Language

This report responds to legislative language set forth in the Explanatory Statement accompanying the Consolidated Appropriations Act, 2008 (2008 Act)[3] and the House Report on the House of Representatives version of the related bill[4].

The Explanatory Statement, at page 570, provides as follows:

> "… *The Department is directed to submit to the House and Senate Committees on Appropriations a report on liquefied natural gas (LNG), as outlined in the House report…*"

House Report 110-185, at page 73, similarly requested the Department of Energy to address several key LNG research priorities in a liquefied natural gas report:

> "… *Liquefied Natural Gas (LNG) Report.—The February 2007 Government Accountability Office report, 'Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification,' found that the most likely public safety impact of an LNG spill is the heat hazard of a fire, but disagreed with the specific heat hazard of a fire and cascading damage failure conclusion, which is used by the Coast Guard to prepare Waterway Suitability Assessments for LNG facilities. Additionally, GAO found that the Department's 'recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel.' Therefore, the Committee directs the Department to incorporate the following key issues, as identified by the expert panel, into its current LNG study: cascading failure, comprehensive modeling (interaction of physical processes), risk tolerability assessments, vulnerability of containment systems (hole size), mitigation techniques, the effect of sea water coming in as LNG flows out, and the impact of wind, weather, and waves.*"

II. LNG Cargo Tank Breach and Spill Analyses

For this study, the larger classes of Moss and Membrane LNG vessels were analyzed. The dimensions of the vessels considered are summarized in Table 1. The sizes selected span many of the LNG vessels used in the U.S., including the largest LNG vessels in operation today.

Table 1. Dimensions of Moss and Membrane LNG Vessels Evaluated

Dimension	Moss	Membrane
Length	280 m (924 ft)	330 m (1090 ft)
Breadth	45 m (150 ft)	54 m (178 ft)
Draft	10.4 m (34 ft)	11.5 m (38 ft)
LNG Cargo Capacity	140,000 m^3	260,000 m^3

[3] Explanatory Statement accompanying Public Law 110-161 (Dec. 26, 2007).
[4] H.Rept. 110-185 accompanying Energy and Water Development Appropriations Bill, 2008 (H.R. 2641) at page 73.

The geometric models, which were created using detailed structural drawings of actual LNG vessels, are shown in cross-sections in Figures 1 and 2.

Figure 1. Moss LNG Vessel cross-section.

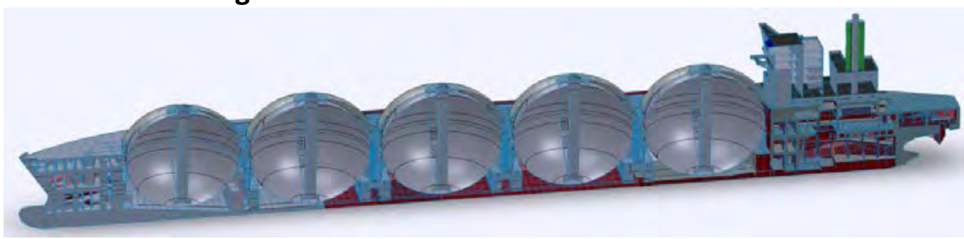
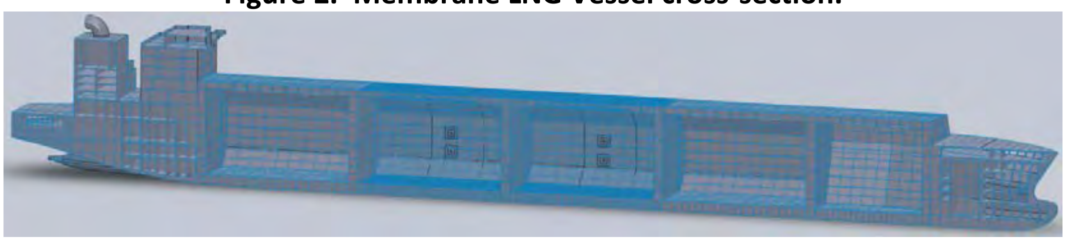


Figure 2. Membrane LNG Vessel cross-section.



LNG Cargo Tank Breach Analyses

Many potential accidental and intentional damage scenarios have been considered for LNG hazard analyses in previous DOE-directed public safety analyses for large LNG spills over water, including Hightower et al., 2004 and Luketa et al., 2008. For this study, Sandia reassessed threats and potential credible event scenarios for LNG marine transportation with marine safety, law enforcement, and intelligence agencies. The evaluations considered a wide range of possible threats. These included accidents, as well as intentional events such as attacks with shoulder-fired weapons, explosives, and attacks by small to medium size boats and aircraft. Potential threats and possible breach events are always site-specific and will vary depending on the location of the LNG vessel, such as inner harbor, outer harbor, or offshore Deep Water port.

The breach sizes calculated were based on detailed, two- and three-dimensional, shock physics/structural interaction and damage models. The breach modeling included detailed representations of the LNG vessel's structural design and materials of construction, cargo tank construction and materials, and the location and energy content of the threats identified. The range of breach sizes calculated for specific threats are presented in classified reports, but Table 2 provides a summary of the range of the cargo tank breach sizes considered for this study. To simplify integration with the structural geometry and construction of LNG vessels, square holes were assumed in all analyses.

Table 2. LNG Cargo Tank Breach Sizes Considered

Type	Breach Area	Breach Dimension
Very Small	0.005 m^2	(0.25 ft x 0.25 ft)
Small	0.5 m^2	(2.3 ft x 2.3 ft)
Medium	2-3 m^2	(5.0 ft x 5.0 ft)
Large	5 m^2	(7.3 ft x 7.3 ft)
Very Large	15 m^2	(12.7 ft x 12.7 ft)

The breach events evaluated can occur at a range of locations. While many accidental and intentional threats fall into the very small and small breach size categories, the major focus of the spill and damage analyses were for medium to very large hole sizes that are difficult to analyze without the use of high performance modeling and computing capabilities.

LNG Spill Analyses

To determine the extent of LNG flow during a breach event, three-dimensional computational fluid dynamics (CFD) analyses of the internal and external flow of LNG from a breach of Moss and Membrane LNG cargo tanks were performed for the small through very large hole sizes. The spill analyses considered the entire flow physics of the problem, including the draining of the breached cargo tank, the timing and flow of the LNG internal and external to the vessel, and LNG vaporization during a spill. The flow modeling and analysis conducted are presented in detail in Figueroa et al., 2011. Figures 3 and 4 show examples of LNG flow analyses conducted for the Moss and Membrane LNG vessels.

Figure 3. Moss LNG vessel spill and internal flow analysis example.

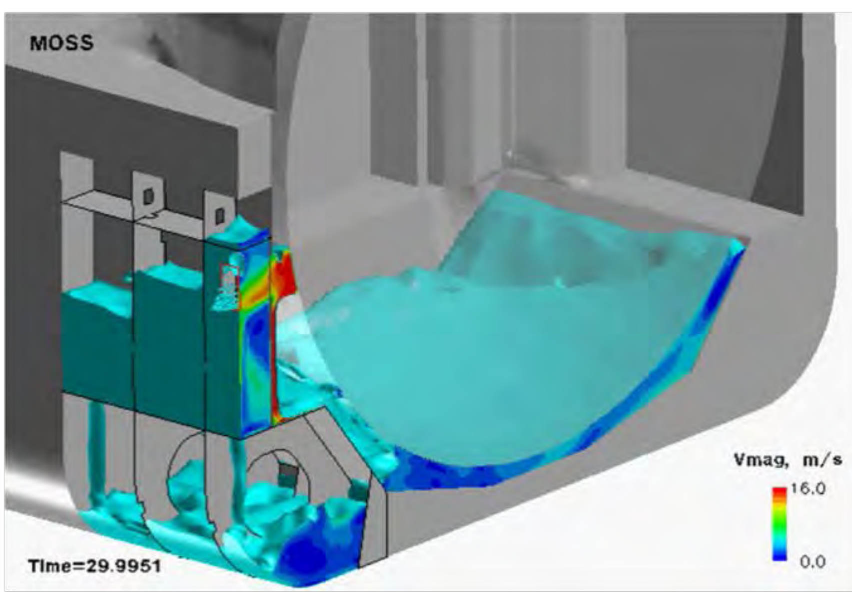
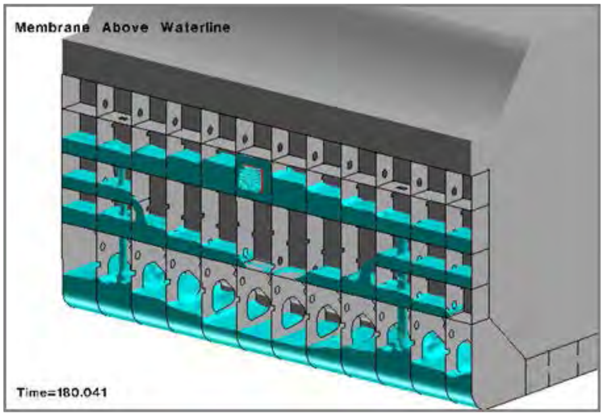
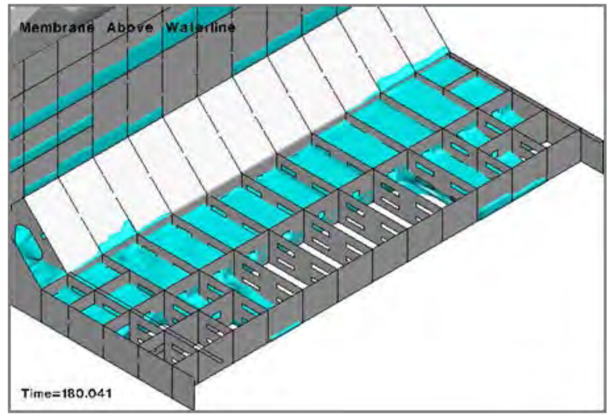


Figure 4. Membrane LNG vessel spill and internal flow analysis examples.





The spill analyses indicate that for the larger breach and spill events, as much as 40 percent of the cargo tank LNG volume will likely remain within the LNG vessel. The spill and flow analyses show that for medium and larger spills, the internal flow of LNG into a Moss LNG vessel will be completed within ten to fifteen minutes, at which time the remaining LNG will all flow out onto the water. For a Membrane LNG vessel, LNG flow within the vessel for medium to larger spills will be completed in about 10 minutes, and then the remaining LNG will flow out onto the water. For smaller breach events, the spills are smaller and the spill durations longer.

The results for the external flow analyses showed that for the larger breach events, LNG pool diameters between 180 m to 350 m can be expected for the Moss LNG vessels, while LNG pool diameters between 205 m to 330 m can be expected for the Membrane LNG vessels. Smaller breach events result in spills of much smaller volumes of LNG and have much smaller pools.

The flow results obtained should be considered as providing qualitative information on the general pattern, timing, and magnitude of the internal and external LNG flows for different breach and spill events.

III. Large LNG Pool Fire Experimental Results

The focus of the efforts for this part of the study was to improve the understanding of the physics and hazards of large LNG spills and fires on water. The key LNG pool fire issues to be addressed included:

- Determining the Surface Emissive Power (SEP) of large LNG pool fires;
- Determining the fuel vaporization rate of LNG fires on water; and
- Determining the flame height to diameter ratios for large LNG pool fires.

This effort was accomplished through the collection of data obtained during a series of LNG pool fire tests on water. A summary of the test data collected is presented here, while the detailed test data and results are presented in Blanchat et al., 2010.

Shown in Figure 5 is the large scale LNG pool fire test site. The site design included: 1) using soil excavated from the creation of a two meter deep, 120 m diameter pond to create a 310,000 gallon compacted soil LNG storage reservoir; 2) covering the reservoir with a double insulated cover and insulated liner to minimize LNG vaporization; 3) use of prefabricated reinforced concrete pipes to transport the LNG from the base of the reservoir to the center of the pool; and 4) use of simple, liftable plugs to allow gravity-driven high LNG flow rates from the reservoir to the pool. This approach enabled LNG flow rates representative of large spills, while minimizing the need for cryogenic rated high flow volume pumps, associated hardware, and fire rated LNG storage tanks.

Figure 5. Large-scale LNG pool fire test site.

Numerous cameras, spectroscopic diagnostics, and heat flux sensors were used to obtain extensive heat flux, flow rate, and fire size data from the resulting fires for each test. The spreading pool fire area was photographed with the aid of gyroscopically stabilized cameras deployed in U.S. Air Force helicopters.

Figures 6 and 7 are pictures of the two large LNG pool fires, conducted in February 2009 and December 2009.

Figure 6. LNG Test 1 – 21 m diameter LNG spill and pool fire.

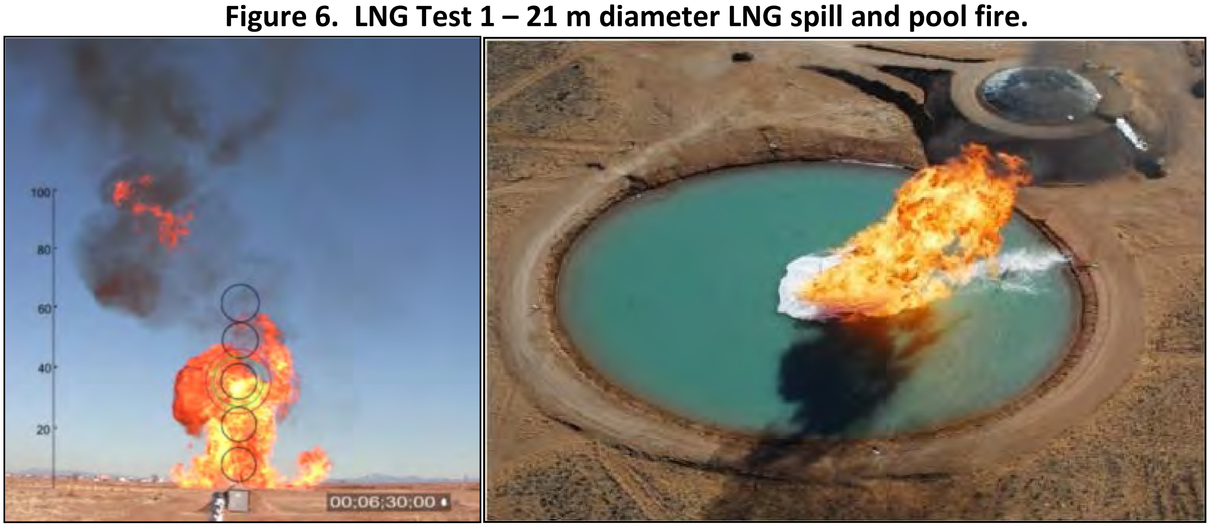


Figure 7. LNG Test 2 – 83 m diameter LNG spill and pool fire.

A summary of the major pool fire parameters measured during these tests are provided below in Table 3.

Table 3. Large LNG Pool Fire Data

Test	Volume Discharged (gallons)	Avg. Flame Height (m)	Flame Diameter (m)	Wind Speed (m/s)	Flame Tilt (degrees)	Vap. Rate (kg/m^2s)	Surface Emissive Power (kW/m^2) (narrow/wide)
1	15,000	70	20.7	4.8	50	0.15	238/277
2	52,000	146	56 (83 m spill)	1.6	Negligible	Not obtained	316/286

The thermal radiation spectra as a function of height and time were acquired using a scanning mid-infrared (1.3-4.8 µm) spectrometer. Analyzed spectra determined that the dominant contributor to the thermal radiation was from broadband soot emission. The overall thermal radiation reaching the spectrometer was attenuated by atmospheric water and CO_2 which resulted in a decrease in intensity at different wavelength bands. In LNG Test 2, at ~40 m to 103 m above the ground surface, the data is fairly consistent with spectra-derived flame temperatures of between 1300-1600°C and emissivity values between ~0.3 -0.4.

In both of the tests conducted for this study, there was no evidence of smoke shielding. There were a few instances when small amounts of smoke were seen in LNG Test 2 during the production of large scale vortices that rolled up from the base of the flame when the fire exhibited a puffing behavior. Very little smoke shielding was also observed in pool fire data obtained from a previous, smaller scale (~10 m diameter) test conducted by SNL.

The trend in the data from these tests indicate that the SEP for LNG fires on water level off at about ~280-290 kW/m^2 and might be expected for spreading pools with diameters in the range of 100 m. This is a reasonable value for use in hazard calculations for structures, such as the LNG vessel or shoreline areas, adjacent to or near the fire. Larger LNG fires would likely have some smoke shielding in the upper portions of the flame plume that will lower the overall flame-average SEP for far afield objects.

The collected data showed some unique and unexpected results. Specifically, the fire diameter was not the same size as the spreading pool diameter, as had been assumed by most analyses to date. Previous studies with stagnant pools in pans resulted in fire diameters the same size as the pool diameter. However, in all such studies, the pans had edges that can result in flame stabilization that would not be available in open water scenarios. The data collected further showed that in both very light and significant cross-winds, the flame will stabilize on objects projecting out of the fire, suggesting the vessel itself will act as a flame anchor.

Flame Height-to-Diameter Testing

To develop a flame height-to-diameter correlation, a large (3 m diameter) gas burner was used to create fully turbulent methane fires at the Sandia Thermal Test Complex, which more closely simulates large fire behavior. The data collected was compared with other common height-to-diameter correlations conducted for smaller and less turbulent fires. The Sandia data collected suggests that the fire height for large LNG spills would be much lower than often used in many fire hazard analyses. The Sandia data suggest the fire height-to-diameter ratios for LNG pool fires greater than 300 m in diameter would be less than 1.5 and would approach 0.7 for LNG pool fires about 1,000 m in diameter. Previously, many studies used a constant height-to-diameter ratio of 1.5. The data from the two large LNG pool fire tests conducted as part of this study closely match the gas burner flame height-to-diameter correlation identified.

IV. LNG Vessel Thermal/Structural Analyses

This section provides a summary of the development of LNG vessel structural steel thermal material property data, LNG vessel cryogenic fracture and fire damage testing and analysis, and development of cryogenic and fire thermal loading models needed to identify the time varying thermal stress states on a vessel structure during a large LNG spill and fire. The detailed material testing, and thermal damage testing and analysis efforts conducted are presented in two technical reports Kalan and Petti, 2011 and (Figueroa et al., 2011).

LNG Vessel Structural Steel Material Property Testing

It is well known that many structural steels are susceptible to low temperature brittle fracturing and high temperature softening. In order to perform the thermal (both cryogenic and high temperature) structural damage analyses required for LNG vessels during a spill and fire, information on vessel structural steel material properties and material response at extreme temperatures (from -161°C for cryogenic LNG temperatures and up to 1000°C for LNG fire temperatures), as well as suitable damage models were required. In both cases, neither existing data nor appropriate damage models existed for LNG vessel steels for this range of temperatures. Therefore, a series of material property and material failure tests were performed on two American Bureau of Shipping (ABS) steels representative of the structural steels used in standard LNG vessel construction. The data collected was used to develop cryogenic fracture and fire-induced structural damage models based on vessel structural features, stress states, and temperatures. The material and cryogenic fracture and damage response testing is summarized here, but is discussed in detail in Kalan and Petti, 2011.

ABS Grades A and EH round bar tensile test data were collected at temperatures ranging from -161°C to 800°C. In addition, notched tension specimens and Charpy V-notch testing was performed from -191^{o}C (far below the brittle transition region) to -24^{o}C (above the brittle transition region) for both ABS steels. The tensile test data showed low residual strength (20 percent of yield strength) of LNG vessel steels at LNG fire temperatures for extended periods. The Charpy V-notch energy absorption test results showed low fracture toughness for both materials at cryogenic LNG temperatures, highlighting the susceptibility to fracture of LNG vessel structural steels if contacted by LNG for any extended period.

LNG Vessel Cryogenic Fracture Testing

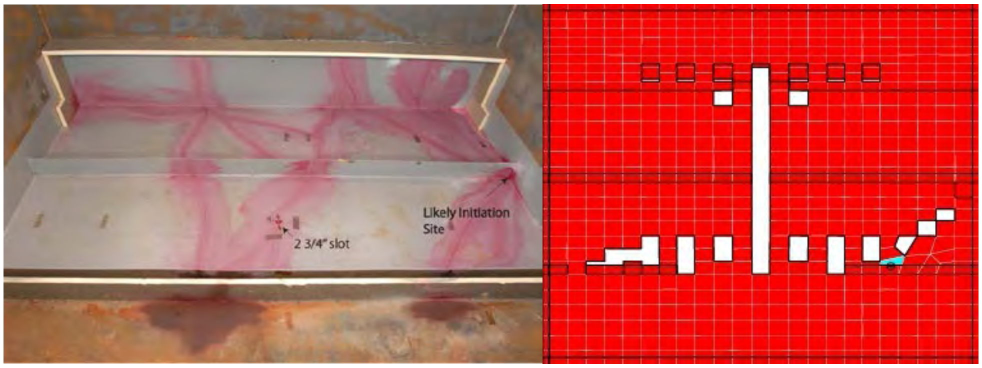
In order to predict how structural sections of an LNG vessel would respond to contact with cryogenic LNG, we conducted a series of large scale LNG spill and fracture tests on ABS Grades A and EH steels. Three series of fracture tests were conducted that included testing of large steel plates that were constrained on their edges, and the testing of large, welded, three dimensional, steel structures representative of LNG vessel structural elements and vessel construction approaches. For these tests, a region in the center of the plate or structure was cooled with liquid nitrogen, which was used for safety considerations. However, testing conducted with LNG showed similar cool down rates of the steel as using liquid nitrogen. The cooling rate and cooling distribution from each test was monitored at several locations on the plates and structures using thermocouples, and fractures were identified after each test. The tests were conducted with prescribed flaw sizes, boundary conditions, and flow rates to provide extensive, high quality data to develop and validate a cryogenic fracture and damage model.

From the fracture data collected, a vessel fracture damage model was developed and was used to predict structural fracture for several simulated LNG vessel structural elements. The development and validation of the cryogenic damage model is discussed in detail in Petti et al., 2011. For verification of the fracture and damage model, a finite element model of a large test structure was developed, and a cryogenic flux was applied to the model that represented the cooling rate data measured in the large structure tests. The cracking observed was compared to the fracturing predicted from the structural model. What was important was to predict the general direction, amount, and propagation of fractures and cracks through structural elements based on the identified temperature and stress states.

Figure 8 shows a comparison of model predictions and test data, and shows that the general extent and direction of cracking is similar relative to crack directions and elements damaged.

These efforts verified that damage could be estimated based on the LNG flow, temperature, and the stress state of the vessel structure.

Figure 8. Comparison of damage analysis to experimental test results.



LNG Vessel Structural Cooling Evaluation

The internal and external regions of the LNG vessel's structure that come into contact with spilled LNG become cooled. To determine cooling rates, experimental data was obtained from a series of structural steel cooling experiments. LNG was pooled on ¾ inch thick carbon steel plates with various surface coatings that included bare steel, primed only, and primed and painted surfaces. The tested surface coatings used consisted of primers and paints used on LNG vessels. The temperature response of the test plates was used to estimate convective heat transfer coefficients. The data and supporting analyses lead to an estimation of lower and upper bound heat transfer coefficients of 400 and 1080 W/m^2-K. The test data also showed that cooling occurs essentially only in the area in contact with the LNG. Based on this data, the regions identified from the flow analysis that come into contact with LNG were reduced linearly in temperature from 20^oC to -148^oC over 10 minutes.

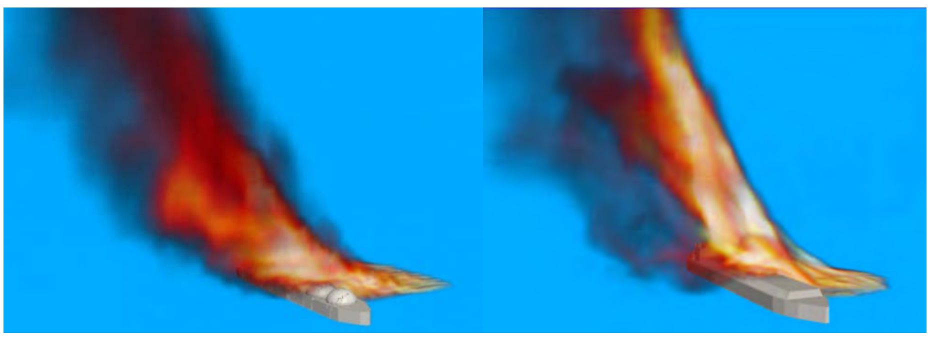
The cooling of LNG vessel steel in contact with seawater was also evaluated. The cooling rates were determined using a finite difference heat transfer analysis. The analysis calculated ice growth depending on the water/ice or water/vessel interface temperature. At interface temperatures below the freezing point of seawater (-1.9°C), the analysis allowed ice to accumulate. For a case with a reasonable external current velocity (1 knot) and for a wide range of bulk seawater temperatures, it was determined sufficient ice forms to insulate the outer hull and allow it to cool to temperatures approaching the temperature of the LNG. The cooling rate calculated was close enough to the cooling rate value determined for air to support using the same cooling rates for vessel steels above and below the waterline contacted by LNG.

LNG Vessel Structural Heating Evaluation

LNG vapors burn at temperatures of about 1500°C, which will negatively impact an LNG vessel's structural integrity if a fire lasts for a significant period of time. For medium to larger spills, the flow analysis indicated the maximum pool diameters would be approximately 180 m to 350 m. Using these pool diameters, pool fire analyses were conducted to estimate the thermal heating rate of the LNG vessel's structural steel. Fuego, a CFD fire code developed and used by Sandia, was used to estimate the envelope of an LNG fire on LNG vessels under various environmental, wind, and humidity conditions. Historical wind speed information was obtained from the National Data Buoy Center (www.ndbc.noaa.gov) for various harbors in the U.S. and was evaluated to obtain a typical wind speed for these harbors. Based on this data, an average wind speed of 9 m/s (20 mph) was considered directed toward the LNG vessels.

As shown in Figure 9, the analyses suggest that in average winds, fire can overlay onto the vessels and impact the tops and sides of the vessels, which should be included in evaluating vessel and cargo tank damage and integrity during a fire.

Figure 9. Large pool fire impacts on Moss and Membrane vessels.



The surface emissive power obtained from the large LNG pool fire experiments was used to define the LNG pool fire heating rates to the LNG vessel structures. Based on these analyses, the temperatures of the outer hulls were calculated to reach approximately 1000^{o}C, while the inner hulls can reach about 775^{o}C. These results compare favorably with vessel hull heating data collected from cargo tank insulation damage testing discussed later in this report. The results suggest that the outer and inner hull structural elements exposed to LNG pool fires for more than 10-20 minutes can experience about a 75 to 80 percent reduction in strength.

V. LNG Vessel Cascading Damage Analyses

The key LNG vessel damage issues Congress wanted addressed as part of this study included:

- Improved understanding of cryogenic fracture and damage to LNG vessels;
- Improved understanding of fire damage to LNG vessels; and
- Improved understanding of the potential for cascading damage from a large spill.

A summary of the cryogenic and fire related vessel damage analyses and the potential for cascading damage to the vessel from an initial spill is presented in this section, while the detailed modeling and analysis results are presented in Petti et al., 2011. The focus of the LNG vessel cascading damage analysis efforts was to use detailed vessel structural and thermal damage models, along with high performance computing resources, to improve the ability to assess and predict cascading damage potential to an LNG vessel from an initial spill.

LNG Vessel Structural Analysis Model Development

For the final vessel cascading damage analyses, detailed finite element structural analysis models were created for both the Moss and Membrane LNG vessels. For the structural analyses, elements with 0.1 m (4 inch) edge lengths were used in the regions where damage and fracturing could potentially occur to allow all of the major structural elements, including the longitudinal stiffeners attached to the inner and outer hulls, to be modeled explicitly in detail. In regions outside of the areas of potential fracturing, the elements were gradually increased to a maximum of approximately 1 m, with most elements in the 0.3 m to 0.5 m range. This helped to reduce the structural analysis complexity and computing resources needed. This approach produced two structural models, each with between four and five million elements.

To ensure the proper mass distributions, both the steel density and the thickness of the shell elements need to be defined as input parameters in the structural models. In the detailed mid-ship sections of the vessel, the thickness of the steel plating was set to the as-built thicknesses since all of the major structural elements were modeled explicitly. For the less detailed fore and aft sections, where the longitudinal stiffeners were not modeled explicitly, the thickness of the inner and outer hulls was increased to account for both the global and local stiffness lost by not including these members. In addition to the thickness of the steel plating, the densities of the blocks in various sections of the vessels were adjusted to account for various non-structural items including LNG cargo, cargo tank insulation, piping, machinery, anchors, fuel, water, etc.

LNG Vessel Damage Analysis Approach

From the spill and flow analyses conducted, the medium to very large breach events give very similar overall LNG flow results within the vessel structures, with the major difference being some variation in the timing of cooling of different regions. For this reason, a single detailed structural damage analysis was performed for each type of LNG vessel. For these analyses, gravitational loads, exterior seawater hydrostatic loads, and internal LNG cargo tank hydrostatic loads were applied to the vessel structural models to first obtain the initial stress states of the vessels. ABS Grade A and EH steels were used to model the structural steel in each vessel. For regions with lower fracture toughness materials (ABS Grades A, B, D, and E) ABS Grade A properties were used, and in regions with higher fracture toughness materials (ABS Grades AH32, AH36, DH32, DH36, EH32, and EH36) ABS Grade EH properties were used. This was done to simplify the structural model input and quality assurance checks needed. The initial load condition chosen was the Summer Arrival Condition where the LNG cargo tanks are 97 percent filled for the Moss LNG vessel and 98.5 percent filled for the Membrane LNG vessel.

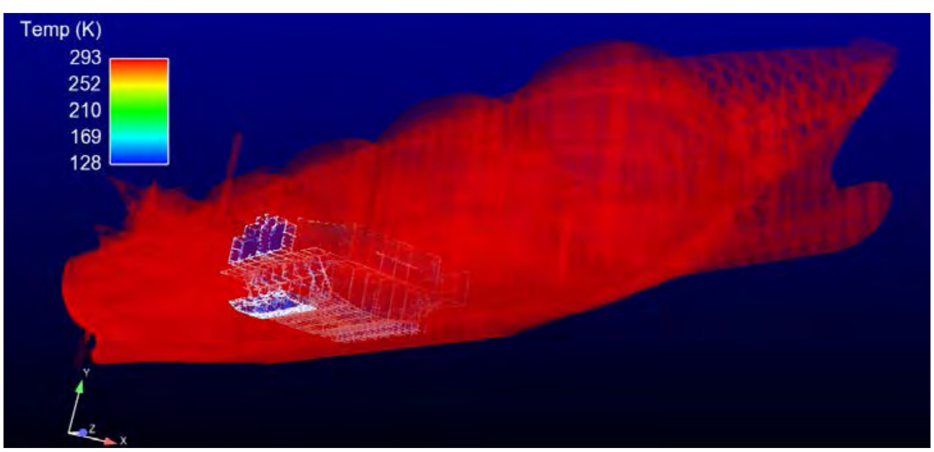
After establishing the initial load and stress states and vessel stability and draft of the structural analysis models for these conditions, temperature changes were applied to the structural models in accordance with the LNG flow, cooling rate, and fire heating rate values discussed in previous sections of this report. These thermal changes, along with the initial stress states and structural steel material properties, were used to track the progression of calculated damage (summarized below) for the LNG vessel. All vessel damage analyses were conducted using high performance computing resources, and the structural damage models were run using approximately 500 parallel computer nodes, each with multiple processors.

Moss LNG Vessel Medium to Large Spill Damage Analysis

The flow analysis showed widespread LNG contact with steel plate surfaces within 30 seconds of a large breach event. As the flow progressed, different regions started to cool at different times. These delays were used to simulate the timing of the flow of LNG within the space surrounding the cargo tank for up to approximately 14 minutes. Beyond that time, the LNG has filled the internal spaces and spills out onto the water. The initial analysis assumed that spilled LNG would not come into contact with the LNG vessel's structure just above the bilge area. However, in some cases the LNG could come into contact with this area. Because of this, the final structural damage results presented include damage in the bilge area in estimating the worst case damage scenarios.

An example of the resulting structural cryogenic damage from a large cargo tank breach and spill is shown in Figure 10.

Figure 10. Example of Moss vessel damage due to cryogenic LNG flow.

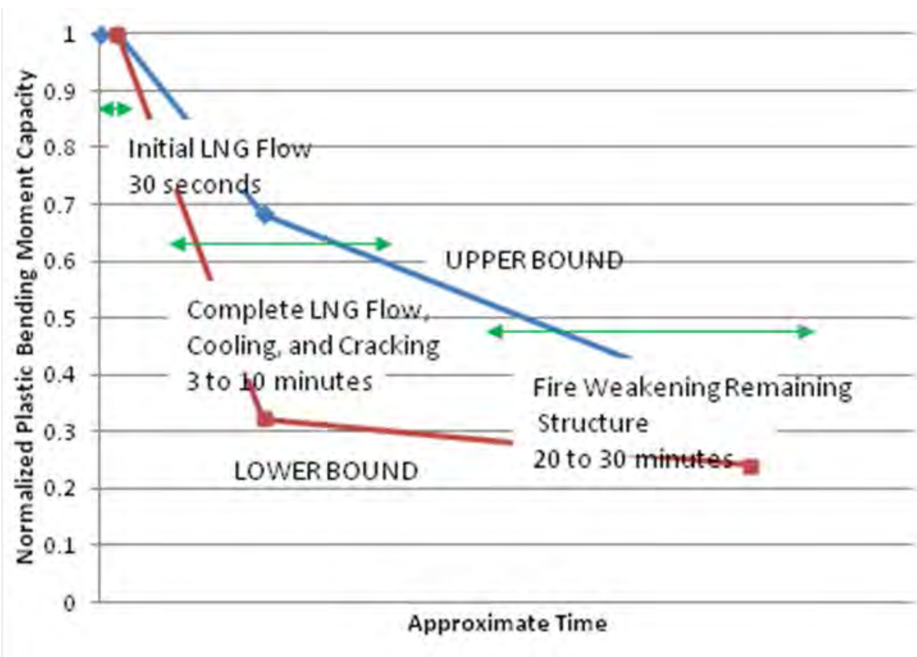


The white colored elements indicate the structural elements that reached the critical fracture damage criterion. The transparent view of the vessel shows both the cryogenic cracking and damage in the outer and inner hull surrounding the cargo tank. The significant damage to the inner hull causes the outer hull to deform upward into the vessel as the hydrostatic pressure from the seawater is no longer resisted by the damaged vessel's inner and outer hulls. The estimated displacement of the outer hull could be as much as one meter. The analysis predicts cryogenic cracking will occur throughout the portions of the vessel that were exposed to LNG flow. No damage was predicted to occur in regions beyond where the LNG flowed.

Based on the cryogenic structural damage analysis, much of the inner hull near a large breach event was damaged. As a result of the pool fire, much of the vessel's structure near the fire on both the side and top of the vessel will reach temperatures of between 775°C and 1000°C for the inner and outer hulls. At these temperatures, the vessel's structural steels are severely weakened, having less than 25 percent of their original strength, and will deform significantly.

Based on the combined cryogenic and fire damage estimated, the plastic bending moment capacity for the Moss LNG vessel as a function of time is presented in Figure 11.

Figure 11. Moss LNG vessel reduction in plastic bending moment capacity for large spills.



The plastic bending moment capacity is defined as the bending moment that would lead to the entire cross-section of the vessel yielding and creating essentially a plastic *hinge*. The plastic bending moment capacity is often used in extreme event risk analyses to evaluate the level of residual structural capacity following an extreme event.

The moment capacity is normalized by the full undamaged plastic moment capacity of the section. The cryogenic damage causes an approximate 30 to 70 percent reduction within

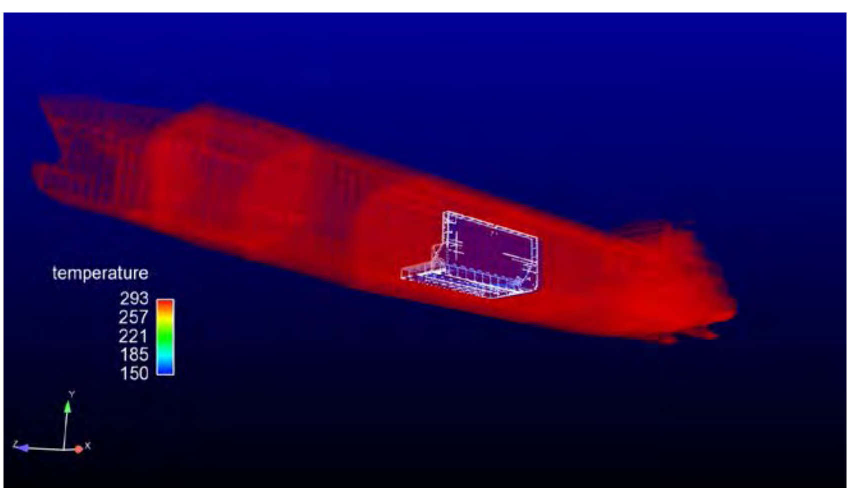
3 to 10 minutes, with the fire causing an additional 10 to 20 percent reduction between 20 and 30 minutes. However, the upper bound capacity estimates assume that the cross-section is in a condition to obtain the full strength of the materials without section buckling. However, the cryogenic damage modeling shows local buckling and material displacement that suggests that the lower bound moment capacity could occur since the sections of the inner and outer hull at the top of the vessel are affected by the fire and have little resistance to tension.

Based on the reduction in plastic moment capacity, the vessel is judged to have essentially no remaining structural strength in the affected region, and will most likely be disabled, severely damaged, and at risk of sinking. Based on the flow and damage analysis, the LNG vessel's structural design limits the LNG flow to the initially damaged region, and the four remaining cargo tanks not breached during the initial event should be unaffected by the cryogenic damage. Also, because the Moss cargo tanks are independent and do not rely on the vessel's hull structure for support, a simultaneous release of LNG from the undamaged cargo tanks due to cascading failure is considered highly unlikely.

Membrane LNG Vessel Medium to Large Spill Damage Analysis

The flow results were used to develop a series of cooled regions for the cryogenic damage analysis. Widespread LNG flow between the inner and outer hulls occurs within 2 and 3 minutes, with subsequent filling of the compartments. At approximately 6 to 10 minutes into the spill, a significant portion of the ballast tank and areas between the inner and outer hulls are filled. While complete filling of the ballast compartments and areas between the double hulls does not occur, the open spaces are small and would contain cold LNG vapor and therefore, the entire ballast tank was included as one large, cooled region. Finally, the same assumptions were made for the Membrane vessel as the Moss vessel regarding cooling rates below the waterline and the eventual entrainment of seawater into the vessel for some breach events and their inclusion in the damage conclusions. Figure 12 shows an example of the Membrane vessel with temperatures and damage plotted.

Figure 12. Example Membrane vessel damage due to cryogenic LNG flow.

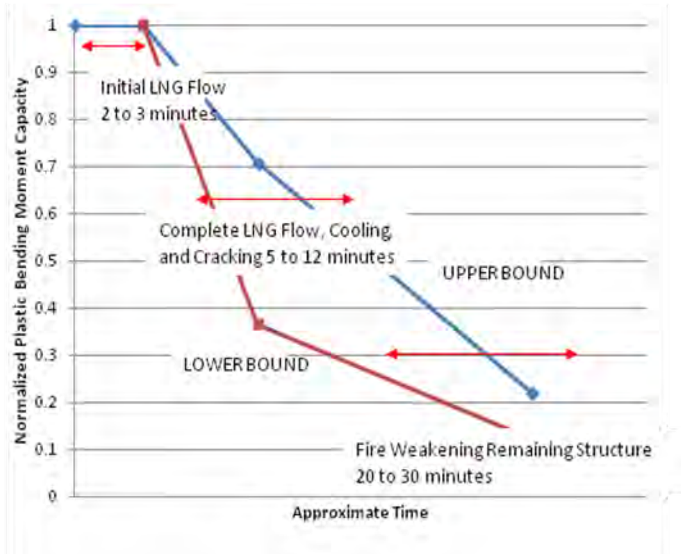


The white colored elements indicate the cryogenic fractures calculated after reaching the critical strain criterion during cooling. The transparent view shows both the cracking in the outer hull and inner hull surrounding the cargo tank. Here, the extent of the damage to vessel structure surrounding the breached cargo tank can be seen. The analysis predicts cracking will occur throughout the entire cooled region, which reflects those portions of the vessel that were exposed to LNG flow.

The damage was predicted to occur primarily near the cooled region boundaries. This is likely an artifact of the sharp gradient from cool to warm material along this boundary. Once the cracks occurred in the structural model, these elements were removed, and much of the stress was reduced in the interior of the cooled region, preventing further apparent damage. The cryogenic fracture and cracking in an actual event is expected to extend throughout much of the cooled region, especially in areas of flaws or stress concentration such as welds, corrosion, and so on. As with the Moss vessel analysis, no damage was predicted to occur in regions outside of the cooled areas. The effective damage to the Membrane LNG vessel is initially localized on one side of the vessel. The majority of the inner and outer hull was damaged, severely reducing the ability of the vessel to resist hydrostatic loads from the surrounding seawater. Unlike the Moss LNG vessel, in which the LNG cargo tank is structurally independent from the inner hull, the Membrane LNG vessel's inner hull provides the structural support for the cargo tank. With the damage to the inner hull, the cargo tank in the affected region will likely not be capable of fully containing the LNG cargo that remains below the breach. This would lead to additional inner hull damage and expanding damage of the inner hull to both sides of the vessel.

From the fire analysis, much of the vessel structure near the fire on both the side and top of the Membrane LNG vessel could reach temperatures of between 775°C and 1000^{o}C for the inner and outer hulls. Since the LNG vessel's inner hull and internal structural members provide the structural support for the Membrane cargo tanks, thermal degradation of both the outer and inner hulls from an LNG pool fire would likely cause damage to the cargo tanks. Based on the cryogenic and fire damage estimated, the reduced cross-sections and weakened materials analysis results were used to estimate the plastic bending moment capacity for the Membrane vessel as a general function of time and are shown in Figure 13.

Figure 13. Membrane LNG vessel reduction in plastic bending moment capacity for large spills.



The cryogenic damage causes an approximate 40 to 70 percent reduction within 5 to 12 minutes (including several minutes to account for the slower flow calculated for the Membrane vessel design) with the fire causing a 80 to 90 percent total reduction in the plastic bending moment capacity between 20 and 30 minutes. The fire has a more significant effect on the Membrane vessel section modulus due to the greater amount of structural cross-section that is exposed to the fire.

The damage to the vessel also introduces concerns related to a reduced buckling capacity for structural regions in compression. The sections of the inner and outer hull at the top of the vessel are affected by the fire and have little resistance to tension. Based on the reduction in plastic bending moment capacity, the vessel is judged to have essentially no remaining structural strength in the affected region, and will most likely be disabled, severely damaged, and at risk of sinking.

Based on the flow and damage analysis, the LNG vessel's structural design limits the LNG flow to the initially damaged region. Although the four remaining cargo tanks were not calculated to have been breached during the initial event, the Membrane cargo tanks are integrated tanks and rely on the vessel's hull structure for support, and the release of their cargo is slightly more uncertain. One of the tanks adjacent to the initially breached tank was calculated to experience cracking in the corner of the inner hull exposed to LNG. The breach of this adjacent tank is possible, but not certain. Even so, if this adjacent tank were to experience a leak, it would most likely progress slowly and/or occur during the fire portion of the event when the fire would weaken the vessel structure in the adjacent tank. This would have the effect of extending the duration of an initial fire, but not increasing the size of the pool fire to any significant degree.

LNG Vessel Damage from Smaller Spills

For very small breach events (0.005m^2 Breach Area; 0.25 ft x 0.25 ft Breach Dimensions; from Table 2), which could occur from a number of credible intentional or accidental events, the spill rates will be more than a factor of 1,000 times less than that of the larger breach events considered. This puts small spills into categories that would typically fall within current spill detection and safety systems and allow a significantly extended response time for both Moss and Membrane LNG vessels. The large reduction in spill rates, cryogenic damage and fire damage potential suggests that should a smaller breach event occur, both Moss and Membrane LNG vessels would have sufficient time to transit to an appropriate anchorage location and work with the Coast Guard and other public safety agencies to perform a damage assessment and initiate appropriate action.

For small breach events (0.5 m^2 Breach Area; 2.3 ft x 2.3 ft Breach Dimensions; from Table 2), the physics of the flow conditions will reduce the LNG flow rate into an LNG vessel by a factor of approximately six, relative to the larger LNG spills, and the full cryogenic cooling and damage of all the compartments between the LNG hulls for each vessel type could take as much as six times as long. However, based on the flow analysis conducted for these holes, the LNG flow internal to the vessel reaches the keels of the LNG vessels only a few minutes later than for the larger spills. This suggests that for spills from small breach events, the full cryogenic damage could take from 10 minutes to 60 minutes longer than for the larger spills. Unfortunately, the fire damage will still occur over the original time period calculated, and therefore the overall reduction in structural capability will most likely occur within one hour of the event.

VI. Additional Cascading Damage Analyses

A number of additional cascading damage issues were addressed in this study, including:

- Cargo tank insulation damage during a fire;
- Overpressure of an LNG cargo tank during a fire;
- Impact of Rapid Phase Transitions (RPTs) during a spill; and
- LNG vaporization, deflagration, and associated damage during a spill.

A summary of the testing and analysis efforts conducted to assess the potential impacts of these kind of cascading damage scenarios is presented in this section, while the detailed test data and analyses are presented in Blanchat et al., 2011, Morrow, 2011, and Figueroa et al., 2011.

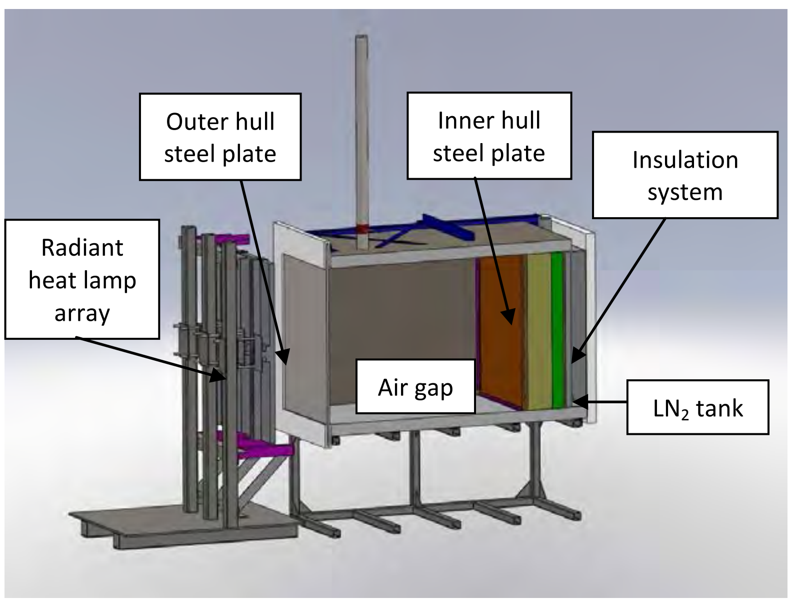
LNG Cargo Tank Insulation Fire Damage Testing

To assess the thermal resistance of LNG cargo tank insulation materials and systems in a fire, large-scale thermal damage experiments and testing were conducted on four major LNG cargo tank insulation systems (two Moss and two Membrane systems), which represent most of the current LNG insulation systems being used in U.S. ports. The testing of each insulation system was coordinated through LNG vessel designers and cargo tank insulation system manufacturers, and each insulation system tested was either provided by the insulation manufacturers or was fabricated at Sandia to the insulation system design and construction specifications provided by the manufacturers. LNG vessel representatives witnessed their insulation system test setup, experiments, data collection and evaluation, and participated in post-test insulation system inspection.

The experiments were designed to test the insulation systems for the fire durations expected from a large LNG spill. Based on the latest information on large-scale LNG spills and associated fires (Luketa et al., 2008), fires from 20 to 40 minutes long might be possible. Therefore, all the insulation systems were tested for at least 40 minutes. All tests were performed using a radiant heat assembly that allowed identical and reproducible heat flux boundary conditions for each test. All tests were performed to yield a continuous incident heat flux to the outer hull (for the membrane) or weather cover (for the Moss) insulation systems of ~270 kW/m^2. This value was based on preliminary, flame-averaged steady-state surface emissive powers measured in the large-scale LNG pool fire tests previously discussed and presented in (Blanchat et al., 2010).

The insulation tests were conducted in the test apparatus shown in Figure 14.

Figure 14: LNG cargo tank insulation testing layout.



It was approximately one meter by one meter square, and approximately two meters long and designed to allow testing of large representative LNG insulation panel systems with minimal edge effects such that a thermal environment representative of a large fire could be created. The testing apparatus included a radiant heat lamp assembly, mild steel plates representing Membrane LNG vessel outer and inner hulls or the Moss LNG vessel weather cover, an air gap inerted with nitrogen during testing, the insulation system being tested, and an aluminum tank filled with liquid nitrogen (LN_2) to represent a cold LNG cargo tank boundary condition. Liquid nitrogen was used for safety reasons, since it is not flammable, and has a similar temperature as LNG.

A summary of all the insulation test results are shown in Table 4. Heat flux was measured by heat flux gauges attached to the tank and by evaluating the change in the liquid nitrogen boil-off rate in the LN_2 tank.

Table 4. LNG Cargo Tank Insulation System Fire Damage Test Results

LNG Vessel	Insulation Type	Thickness	Fire Survivability	LN_2 Tank Heat Flux
Moss	Extruded polystyrene panel	~300 mm	> 40 min	< 7 kW/m^2
Moss	Polyurethane foam/ phenolic resin foam composite panel	~300 mm	> 40 min	< 5 kW/m^2
Membrane	Polyurethane foam and plywood panel	~300 mm	> 40 min	< 5 kW/m^2
Membrane	Perlite-filled plywood boxes	~500 mm	> 40 min	< 5 kW/m^2

LNG Cargo Tank Pressure Safety Relief Valve Evaluation

There has been much discussion on the impacts of a large LNG pool fire on increasing vaporization of LNG in undamaged tanks and the capacity of the current pressure safety relief valves to handle this increased vaporization. The concern is that if pressure builds up during a fire and cannot be adequately handled by the pressure safety relief valve systems, then a cargo tank could become over-pressurized, fail, lead to additional LNG spills, and increase hazards. A particular concern was Moss LNG cargo tanks, since some Moss insulation systems were considered to be quite vulnerable to high temperature degradation.

The significant reduction in heat transfer levels measured in the insulation damage testing discussed previously indicates that during the tests, charred insulation and soot formation is interfering with flux between the weather cover and the liquid nitrogen tank. Several possibilities exist; the atmosphere between the two surfaces could be acting as a participating media blocking heat flow. Alternatively, a very thin layer of insulation is left on the surface of the tank interfering with heat flux, or the charred insulation continues to act as a heat flux barrier along with the undamaged insulation. These possibilities suggest that different heat flux models should be considered and assessed.

Therefore, three models were considered as a way to bracket the potential range of heat flux values that an LNG cargo tank could experience during a fire. The estimates of heat flux to the cargo tank based on the experimental data and analysis from the cargo tank insulation damage testing suggests a potential range of values from 3-7 kW/m^2, with a most likely minimum value of ~5 kW/m^2. This value would be representative of a simple radiation heat transfer value. In considering both a participating media heat transfer analysis and a free convection heat transfer analysis for a Moss LNG cargo tank, the analyses support maximum heat flux estimates of up to 10 kW/m². Based on the fire modeling information, these heat flux values can be assumed to occur during free convection over the full tank surface area, including the area of the cargo tank below the main deck of the LNG vessel.

From the analyses, a heat flux of 5 kW/m² will result in an average pressure equivalent to the normal operating pressure of the cargo tank (~1.3 psig). A heat flux of 10 kW/m² will result in an average pressure of ~2.8 psig, and for the free convection case, a pressure of ~14.7 psig. Moss LNG cargo tanks are constructed to a design pressure which significantly exceeds the highest estimated pressure from the above scenarios. While the increased heat flux will cause some vaporization of the LNG in the vessel's cargo tanks, the cargo tank pressure relief valves are adequately sized to handle the resulting vapor production rates. Due to the combination of adequately sized cargo tank pressure relief valves and cargo tank design standards, there is a minimal likelihood of a Moss LNG cargo tank being damaged from a fire due to vapor over pressurization.

This approach was compared to an analysis performed by the Society of International Gas Tanker and Terminal Operators (SIGTTO) in 2009. This was an industry-wide study conducted to assess LNG cargo tank safety relief valve performance in the face of a large pool fire. The SIGTTO approach used standard handbook sizing algorithms and simplifying assumptions on fire/vessel interactions and cargo tank insulation damage rates, but reached similar conclusions. Overall, the testing and analyses suggest that the Moss LNG cargo tank insulation materials currently used can provide protection of the cargo tanks in a fire, and LNG vaporization would not increase to a level that would exceed the pressure safety relief valve capacity or damage the LNG vessel's cargo tanks. These analyses are presented in greater detail in Morrow, 2011.

LNG Vaporization and Deflagration Analysis

During an LNG spill, as the cryogenic LNG flows over the relatively warm structural steel within an LNG vessel, the LNG will begin to vaporize. Likewise, if a breach is at, near, or below the waterline, the LNG will also vaporize when it comes in contact with the relatively warm water. In both cases, the methane generated is flammable within a certain concentration range by volume in air (5 to 15 percent). Below five percent concentration, the vapor is too lean to burn, and above 15 percent concentration there is not enough air to sustain combustion.

During the spill flow analyses conducted, LNG vaporization and concentrations were also calculated. This provided an estimate of the amount and timing of the vapor generated and the likelihood of ignition, especially between the double hulls. In evaluating the calculated vaporization data, the combustible vapor concentrations varied spatially and temporally in each compartment and the ignitable concentrations in any region only lasted a few to ten seconds. Therefore, it is unlikely that ignition of methane vapors would occur inside the double hull compartments.

LNG Spill on Water Rapid Phase Transition Damage Analysis

A Rapid Phase Transition (RPT) is a phenomenon observed when two liquids of very different temperatures come into contact. LNG spilled onto water and undergoing a series of RPTs can create localized overpressures that look, sound, and behave like a small explosions. Where the explosive pressure is confined or where it is near structural elements, severe structural damage can occur.

In a review of the existing RPT information and data from LNG spills on water, the primary observation is that RPTs generally occur when LNG is either poured at high velocity onto water, or when water is sprayed at high velocity onto LNG. Therefore, we used the LNG flow results to identify and evaluate events with high LNG mixing rates. The results show that only a few events cause significant mixing. Those events that create the most mixing, and therefore the greatest likelihood of RPTs, occur relatively far away from an LNG vessel's outer hull. Therefore, the direct or additional damage of an RPT or a series of RPTs on the LNG vessel's outer hull is possible, but would likely cause minimal additional damage to the vessel.

VII. Large LNG Pool Fire Hazard Analyses

In this section we provide summarized thermal hazard distances resulting from large LNG spills and pool fires on water using solid flame models while the information is presented in detail in Luketa, 2011. The LNG pool fire hazard analysis parameters used in the 2004 and 2008 Sandia LNG reports (Hightower, et al. 2004) (Luketa, 2008) were based on LNG pool fire data of much smaller scale. In keeping with the principle of using the best available data, the parameters in those reports have been updated to reflect the newly acquired LNG pool fire and cascading damage data from this study. The former and updated fire parameter values are noted in Table 5 and are appropriate for use with common Solid Flame Fire Models. These types of models are suggested for their ease of use in estimating general hazard distances for a range of spills (Luketa, 2011).

Table 5: Recommended Nominal Values for Solid Flame Model

Nominal value	*2004 and 2008 Sandia LNG reports*	*Current report*
Burn rate (m/s)	3.0×10^{-4}	3.5×10^{-4}
Flame height (m)	Moorhouse correlation	Sandia correlation
SEP (kW/m^2)	220	286
Transmissivity	0.8	Wayne formula

As in the 2004 and 2008 Sandia reports, it must be emphasized that hazard distances from an LNG spill and fire will change depending on site-specific environmental conditions and breach scenarios, and site-specific analyses should be considered when appropriate.

Table 6 provides predicted thermal hazard distances for intentional events using the updated parameters and the same scenario matrix for hole sizes and tanks breached as presented in the 2004 Sandia report, which are contained in Table 7. The average pool size is calculated using the same approach as in the 2004 report, and the discharge coefficients also have not changed. Note the calculated pool diameter for the nominal cases are representative of pool diameters of 180 m to 350 m calculated for the spill and flow analyses conducted for this study.

The updated parameter values suggest the use of a higher heat flux, lower flame height, and the same pool diameters previously used, which result in about a two percent decrease in the thermal hazard distances relative to those predicted in the 2004 Sandia report for spills from smaller LNG vessels. Using the same approach, the hazard distances are reduced by about 7 to 8 percent relative to the 2008 Sandia report for larger vessels and larger spills.

From a cascading damage viewpoint, the analyses presented suggest that significant LNG vessel damage is likely from a large spill, but the major damage occurs about 15-30 minutes after an initial breach and spill. This is about the same time that a fire from an initial breach will begin to die out from a large spill. Therefore, it is expected that if cascading damage occurs, it will likely be a sequential, but not simultaneous, breach of other LNG cargo tanks, and suggests that evaluating hazard distances based on a nominal one-tank spill, with a maximum of a three-tank spill, as has been recommended in the 2004 Sandia report, is still appropriate for estimating hazard distances.

Table 6: Thermal hazard distances using parameters from the 2009 large pool fire test data

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	τ	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
INTENTIONAL EVENTS									
2	3	0.6	3.3×10^{-4}	286	nom	199	20	299	895
5	3	0.6	3.3×10^{-4}	286	nom	546	8.1	697	1894
5*	1	0.6	3.3×10^{-4}	286	nom	315	8.1	433	1266
5	1	0.3	3.3×10^{-4}	286	nom	223	16	329	974
5	1	0.6	1.9×10^{-4}	286	nom	415	8.1	471	1180
5	1	0.6	5.1×10^{-4}	286	nom	253	8.1	393	1252
5	1	0.6	3.3×10^{-4}	286	low	315	8.1	320	922
5	1	0.6	3.3×10^{-4}	248	nom	315	8.1	404	1183
5	1	0.6	3.3×10^{-4}	326	nom	315	8.1	479	1347
12	1	0.6	3.3×10^{-4}	286	nom	488	3.4	636	1748

*nominal case

Table 7: Thermal hazard distances in the 2004 Sandia LNG report

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	τ	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
INTENTIONAL EVENTS									
2	3	.6	3×10^{-4}	220	.8	209	20	250	784
5	3	.6	3×10^{-4}	220	.8	572	8.1	630	2118
5*	1	.6	3×10^{-4}	220	.8	330	8.1	391	1305
5	1	.3	3×10^{-4}	220	.8	233	16	263	911
5	1	.6	2×10^{-4}	220	.8	395	8.1	454	1438
5	1	.6	8×10^{-4}	220	.8	202	8.1	253	810
5	1	.6	3×10^{-4}	220	.5	330	8.1	297	958
5	1	.6	3×10^{-4}	175	.8	330	8.1	314	1156
5	1	.6	3×10^{-4}	350	.8	330	8.1	529	1652
12	1	.6	3×10^{-4}	220	.8	512	3.4	602	1920

*nominal case

VIII. LNG Spill Prevention and Risk Management

As noted in both the 2004 and 2008 Sandia LNG reports, risk prevention and mitigation techniques can be important tools in reducing both the potential for a spill and the hazards from a spill, especially in locations where the potential impact on public safety and property can be high. However, what might be applicable for cost-effective risk reduction in one location might not be appropriate at another location. Therefore, coordination of risk prevention and management approaches with local and regional emergency response and public safety officials is important in providing a comprehensive, efficient, and cost-effective approach to protect the public and property at a given LNG import or export location.

From an LNG vessel damage viewpoint, the analyses conducted and presented in this report suggest that significant damage is likely to LNG vessels from medium and large breach events and spills. Therefore, a large breach and spill could have both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterway commerce at some sites. For this reason, significantly more attention and proactive measures should be considered for preventing the possibility of larger breach and spill events or for mitigating the cryogenic and fire impacts of larger spills on LNG vessels.

Risk management options should be focused on approaches that can be used to actively prevent or mitigate larger spills. Some risk management approaches that can be considered to help reduce the possibility of an event occurring, or reduce the hazards to the vessel and the public should an event occur include:

- Implementation of enhanced operational security measures, to include:
    - Positive control of other vessel movements during LNG vessel transits and operations;
    - Review of LNG vessel escort protocols and operations to improve the ability to enforce exclusion zones through enhanced standoff and active interdiction approaches;
- Review of port operational contingency plans to ensure procedures are in place to address larger spills, to include options for moving the vessel to a safe anchorage to monitor, inspect, and assess damage, and for longer-term response options, including vessel lightering;
- Review of emergency response coordination and procedures for the LNG vessel, terminal or port, port authority, and emergency response groups to reduce the overall impacts and consequences of larger spills; and
- Review LNG vessel design, equipment, and operational protocols for improved fire protection to the LNG vessel, terminals, and vessel personnel from a large LNG fire.

IX. Conclusions

The major findings for smaller breach events include:

- For the very small breach events, which could occur from a number of credible accidental or intentional events, the spill rates are more than a 1,000 times less than that of potential larger breach events.
- This puts smaller spills into a regime that would typically fall within current spill detection and safety systems on LNG vessels such that it is extremely likely there would be sufficient time to move the vessel to a safe anchorage to monitor, inspect, and assess damage and long-term response options.

The major findings for medium and larger breach events:

- Large-scale fracture testing, cryogenic flow analyses, and fire modeling indicated that LNG vessels would be disabled, severely damaged, and at risk of sinking.
- For these events, LNG vessels would not be capable of movement to a safe anchorage, and would require longer periods to monitor, inspect, assess, and establish long-term response and remediation measures.

The major findings for Cascading Damage Hazards:

- Current LNG vessel and cargo tank design, materials, and construction practices are such that simultaneous multi-cargo tank cascading damage spill scenarios are extremely unlikely, though sequential multi-cargo tank cascading damage spill scenarios are possible.

- Should sequential cargo tank spills occur, they are not expected to increase hazard distances resulting from an initial spill and pool fire, but could increase the duration of the fire hazards.
- Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from a large LNG pool fire will decrease by at least 2 to 7 percent compared to results obtained from previous studies.
- Risk management strategies to reduce potential LNG vessel vulnerability and damage from breach events which can result in large spills and fires should be considered for implementation as a means to eliminate or reduce both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterways commerce.

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Exhibit 7

SANDIA REPORT

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Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water

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Abstract

While recognized standards exist for the systematic safety analysis of potential spills or releases from LNG (Liquefied Natural Gas) storage terminals and facilities on land, no equivalent set of standards or guidance exists for the evaluation of the safety or consequences from LNG spills over water. Heightened security awareness and energy surety issues have increased industry's and the public's attention to these activities. The report reviews several existing studies of LNG spills with respect to their assumptions, inputs, models, and experimental data. Based on this review and further analysis, the report provides guidance on the appropriateness of models, assumptions, and risk management to address public safety and property relative to a potential LNG spill over water.

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To support the technical analysis required for this project, the authors worked with many organizations, including maritime agencies, LNG industry and ship management agencies, LNG shipping consultants, and government intelligence agencies to collect the background information on ship and LNG cargo tank designs, accident and threat scenarios, and LNG ship safety and risk management operations needed to assess LNG spill safety and risk implications.

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Richard Hoffmann – Federal Energy Regulatory Commission
Chris Zerby – Federal Energy Regulatory Commission

To help in technically reviewing this report, the DOE commissioned an External Peer Review Panel to evaluate the analyses, conclusions, and recommendations presented. The Peer Review Panel consisted of experts in LNG spill testing and modeling, fire modeling, fire protection, and fire safety and risk management. The panel's comments and suggestions were extremely valuable in improving the technical presentation and organization of the report. The authors would like to thank the following members of the External Peer Review Panel for their valuable comments, suggestions, and directions.

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Dr. Carlos Fernandez-Pello – Professor of Fire Sciences, University of California Berkeley
Dr. Ron Koopman – Consultant on LNG spills and modeling
Dr. Fred Mowrer – Associate Professor of Fire Protection Engineering, University of Maryland

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SYMBOLS AND ACRONYMS

<	less than
>	greater than
/	per
ºC	degrees Celsius
ºF	degrees Fahrenheit
ºK	degrees Kelvin
g	gram
k	kilo- (multiplied 1000 times; e.g. 5 kW = 5000 watts)
knot	nautical mile per hour (1 knot = 1.15 miles per hour)
m	meter (1 m = 39.37 inches)
m^2	meter squared (an area measuring one meter on each side)
m (as a prefix)	milli- (1/1000; e.g., 1 mm = 1/1000 of a meter)
s	second
Tcf	Trillion cubic feet
W	Watt
(CFD) Computational Fluid Dynamics	a modern analysis technique using computer technology to numerically solve the complete nonlinear partial differential equations governing complex fluid flows
Credible event	a group (or groups) could have the general means and technical skill to accomplish successfully an intentional breach.
(LFL) Lower Flammability Limit	lowest concentration of a fuel by volume mixed with air that is flammable
(LNG) Liquefied Natural Gas	natural gas that has been cooled to a temperature such that the natural gas becomes a liquid
Nominal Case	expected outcomes of a potential breach and associated thermal hazards based on an assessment of identified credible threats and the use of best available data to select model input parameters
(RPT) Rapid Phase Transitions	the rapid evaporation of a liquid resulting from contact with another liquid that is at a temperature significantly above the boiling temperature of the evaporating liquid
(UFL) Upper Flammability Limit	highest concentration of a fuel by volume mixed with air that is flammable
Validation	comparison of analytical results from a model with experimental data to ensure that the physical bases and assumptions of the model are appropriate and produce accurate results

FOREWORD

The Energy Information Administration (EIA) estimates that domestic natural gas production is expected to increase more slowly than consumption, rising to 20.5 trillion cubic feet (Tcf) in 2010 and 21.9 Tcf in 2025. Domestic gas production is relatively flat, while the marginal costs of domestic production are increasing, which has caused a fundamental shift in long-term gas prices. At the same time, gas demand is rising sharply, particularly for electric power generation. The National Petroleum Council (NPC) states in its recent report, "*Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy,"* that "traditional North American producing areas will provide 75% of long-term U.S. gas needs, but will be unable to meet projected demand," and that … "New, large-scale resources such as LNG and Arctic gas are available and could meet 20%-25% of demand, but are higher-cost and have long lead times."

The combination of higher natural gas prices, rising natural gas demand, and lower liquefied natural gas (LNG) production costs, is setting the stage for increased LNG trade in the years ahead. Estimates are that worldwide LNG trade will increase 35 percent by 2020. In the United States, EIA projects that natural gas imports will more than double over the next 20 years. Nearly all the projected increase is expected to come from LNG, requiring an almost 28-fold increase in LNG imports over 2002 levels.

The United States currently has four marine LNG import terminals: Lake Charles, Louisiana; Everett, Massachusetts; Elba Island, Georgia; and Cove Point, Maryland. EIA projects that three new LNG terminals could be constructed in the U.S. in the next 4 to 5 years, and others have estimated that as many as eight could be constructed within this time frame. More than 40 new marine LNG terminal sites are under consideration and investigation. A major factor in the siting of LNG import terminals is their proximity to a market, enabling natural gas to be easily supplied to areas where there is a high demand, but limited domestic supplies. For this reason, marine LNG import terminals are being proposed or considered near major population centers on all three U.S. coasts.

For more information on North American natural gas supply and demand, please refer to the latest *Annual Energy Outlook* of the Energy Information Administration (EIA). The EIA (www.eia.doe.gov) is the statistical agency of the Department of Energy. It provides policy-independent data, forecasts, and analyses to promote sound policy-making, efficient markets, and public understanding regarding energy and its interaction with the economy and environment. Also useful is the National Petroleum Council (NPC) report, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy* (www.npc.org). This multi-volume report was prepared in response to a request from the Secretary of Energy for a new study on natural gas markets in the 21st century, to update the NPC's 1992 and 1999 reports on the subject. It provides insights on energy market dynamics, as well as advice on actions that can be taken by industry and Government to ensure adequate and reliable supplies of energy for customers.

1 EXECUTIVE SUMMARY

The increasing demand for natural gas in the U.S. could significantly increase the number and frequency of marine LNG imports. While many studies have been conducted to assess the consequences and risks of potential LNG spills, the increasing importance of LNG imports suggests that consistent methods and approaches be identified and implemented to help ensure protection of public safety and property from a potential LNG spill.

For that reason, the U.S. Department of Energy (DOE), Office of Fossil Energy, requested that Sandia National Laboratories (Sandia) develop guidance on a risk-based analysis approach to assess and quantify potential threats to an LNG ship, the potential hazards and consequences of a large spill from an LNG ship, and review prevention and mitigation strategies that could be implemented to reduce both the potential for and the risks of an LNG spill over water. Specifically, DOE requested:

- An in-depth literature search of the experimental and technical studies associated with evaluating the safety and hazards of an LNG spill from an LNG cargo tank ship;
- A detailed review of four recent spill modeling studies related to the safety implications of a large-scale LNG spill over water;
- Evaluation of the potential for breaching an LNG ship cargo tank, both accidentally and intentionally, identification of the potential for such breaches and the potential size of an LNG spill for each breach scenario, and an assessment of the potential range of hazards involved in an LNG spill; and
- Development of guidance on a risk-based approach to analyze and manage the threats, hazards, and consequences of an LNG spill over water to reduce the overall risks of an LNG spill to levels that are protective of public safety and property.

To support this effort, Sandia worked with the U.S. DOE, the U.S. Coast Guard, LNG industry and ship management agencies, LNG shipping consultants, and government intelligence agencies to collect background information on ship and LNG cargo tank designs, accident and threat scenarios, and standard LNG ship safety and risk management operations. The information gathered was used to develop accidental and intentional LNG cargo tank breach scenarios, for modeling of potential spill hazards, and as the basis for analysis to determine the extent and severity of LNG spill consequences. Based on analysis of the modeling results, three consequence-based hazard zones were identified plus. In addition, risk reduction and mitigation techniques were identified to reduce impacts on public safety and property.

Several conclusions and recommendations were developed based on these results. The key conclusions are listed below.

Key Conclusions

1. The system-level, risk-based guidance developed in this report, though general in nature (non site-specific), can be applied as a baseline process for evaluating LNG operations where there is the potential for LNG spills over water.
2. A review of four recent LNG studies showed a broad range of results, due to variations in models, approaches, and assumptions. The four studies are not consistent and focus only on consequences rather than both risks and consequences. While consequence studies are important, they should be used to support comprehensive, risk-based management and planning approaches for identifying, preventing, and mitigating hazards to public safety and property from potential LNG spills.
3. Risks from accidental LNG spills, such as from collisions and groundings, are small and manageable with current safety policies and practices.
4. Risks from intentional events, such as terrorist acts, can be significantly reduced with appropriate security, planning, prevention, and mitigation.
5. This report includes a general analysis for a range of intentional attacks. The consequences from an intentional breach can be more severe than those from accidental breaches. Multiple techniques exist to enhance LNG spill safety and security management and to reduce the potential of a large LNG spill due to intentional threats. If effectively implemented, these techniques could significantly reduce the potential for an intentional LNG spill.
6. Management approaches to reduce risks to public safety and property from LNG spills include operation and safety management, improved modeling and analysis, improvements in ship and security system inspections, establishment and maintenance of safety zones , and advances in future LNG off-loading technologies. If effectively implemented, these elements could reduce significantly the potential risks from an LNG spill.
7. Risk identification and risk management processes should be conducted in cooperation with appropriate stakeholders, including public safety officials and elected public officials. Considerations should include site-specific conditions, available intelligence, threat assessments, safety and security operations, and available resources.
8. While there are limitations in existing data and current modeling capabilities for analyzing LNG spills over water, existing tools, if applied as identified in the guidance sections of this report, can be used to identify and mitigate hazards to protect both public safety and property. Factors that should be considered in applying appropriate models to a specific problem include: model documentation and support, assumptions and limitations, comparison with data, change control and upgrade information, user support, appropriate modeling of the physics of a spill, modeling of the influence of environmental conditions, spill and fire dynamics, and peer review of models used for various applications. As more LNG spill testing data are obtained and modeling capabilities are improved, those advancements can be incorporated into future risk analyses.
9. Where analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain or structures can occur, modern, validated computational fluid dynamics (CFD) models can be used to improve analysis of site-specific hazards, consequences, and risks.

10. LNG cargo tank hole sizes for most credible threats range from two to twelve square meters; expected sizes for intentional threats are nominally five square meters.
11. The most significant impacts to public safety and property exist within approximately 500 m of a spill, due to thermal hazards from fires, with lower public health and safety impacts at distances beyond approximately 1600 m.
12. Large, unignited LNG vapor releases are unlikely. If they do not ignite, vapor clouds could spread over distances greater than 1600 m from a spill. For nominal accidental spills, the resulting hazard ranges could extend up to 1700 m. For a nominal intentional spill, the hazard range could extend to 2500 m. The actual hazard distances will depend on breach and spill size, site-specific conditions, and environmental conditions.
13. Cascading damage (multiple cargo tank failures) due to brittle fracture from exposure to cryogenic liquid or fire-induced damage to foam insulation was considered. Such releases were evaluated and, while possible under certain conditions, are not likely to involve more than two or three cargo tanks for any single incident. Cascading events were analyzed and are not expected to greatly increase (not more than 20%-30%) the overall fire size or hazard ranges noted in Conclusion 11 above, but will increase the expected fire duration.

1.1 Safety Analysis and Risk Management of Large LNG Spills over Water

In modern risk analysis approaches, the risks associated with an event are commonly defined as a function of the following four elements:

- The probability of the event — such as an LNG cargo tank breach and spill;
- The hazards associated with the event — such as thermal radiation from a fire due to an LNG spill;
- The consequences of the event — such as the thermal damage from a fire, and
- The effectiveness of systems for preventing the event or mitigating hazards and consequences — such as any safety/security systems.

1.1.1 LNG Spill Prevention and Mitigation

Risks from a potential LNG spill over water could be reduced through a combination of approaches, including 1) reducing the potential for a spill, 2) reducing the consequences of a spill, or 3) improving LNG transportation safety equipment, security, or operations to prevent or mitigate a spill.

For example, a number of international and U.S. safety and design standards have been developed for LNG ships to prevent or mitigate an accidental LNG spill over water. These standards are designed to prevent groundings, collisions, and steering or propulsion failures. They include traffic control, safety zones around the vessel while in transit within a port, escort by Coast Guard vessels, and coordination with local law enforcement and public safety agencies. In addition, since September 11, 2001, further security measures have been implemented to reduce the potential for intentional LNG spills over water. They include earlier notice of a ship's arrival (from 24 hours to 96 hours), investigation of crew backgrounds, at-sea boardings of LNG ships and special security sweeps, and positive control of an LNG ship during port transit.

Proactive risk management approaches can reduce both the potential for and hazards of such events. These are discussed in Section 6 of this report, and include:

- Improvements in ship and terminal safety/security systems,
- Modifications and improvements in LNG tanker escorts, vessel movement control zones, and safety operations near ports and terminals,
- Improved surveillance and searches,
- Redundant or offshore mooring and offloading systems, and
- Improved emergency response coordination and communications.

Risk prevention and mitigation techniques can be important tools in reducing both the potential for and the hazards of a spill, especially in zones where the potential impact on public safety and property can be high. However, what might be applicable for effective risk reduction in one location might not be appropriate at another. The options identified in Table 1 provide examples of how implementation of different strategies, alone or in combination, can be used to reduce certain threats, mitigate consequences of a spill, or reduce hazard analysis uncertainties.

Table 1: Representative Options for LNG Spill Risk Reduction

IMPACT ON PUBLIC SAFETY	REDUCTION IN EVENT POTENTIAL (Prevention)	IMPROVE SYSTEM SECURITY AND SAFETY (Mitigation)	IMPROVED HAZARD ANALYSIS (Reduce Analytical Uncertainties)	RESULTANT RISK REDUCTION
High and Medium	▪ Early off-shore interdiction ▪ Ship inspection ▪ Control of ship, tug and other vessel escorts ▪ Vessel movement control zones (safety/security zones) ▪ One-way traffic ▪ LNG offloading system security interlocks	▪ Harbor pilots ▪ Ship and terminal safety and security upgrades ▪ Expanded emergency response and fire fighting to address fires, vapor clouds, and damaged vessels	▪ Use of validated CFD models for LNG spill and thermal consequence analysis for site specific conditions ▪ Use of CFD and structural dynamic models for spill/structure interactions	Combination of approaches to reduce risks to acceptable levels
Low	Use of existing best risk management practices on traffic control, monitoring & safety zones	Use of existing best risk mitigation practices to ensure risks remain low	Use of appropriate models to ensure hazards are low for site-specific conditions	Combination of approaches to ensure risks are maintained at acceptable levels

To help reduce the risks to public safety and property from both accidental and intentional events, this report provides guidance on risk-based approaches for analyzing and managing the threats, hazards, and consequences of an LNG spill over water. The guidance is summarized in the remainder of the Executive Summary and presented in detail in Sections 3 – 6 of this report and in technical discussions in Appendices A – D.

1.1.2 LNG Breach, Spill, and Hazard Analyses

Currently, the potential for an LNG cargo tank breach, whether accidental or intentional, the dynamics and dispersion of a large spill, and the hazards of such a spill, are not fully understood, for two primary reasons. First, the combination of current LNG ship designs and safety management practices for LNG transportation have reduced LNG accidents to the extent that there is little historical or empirical information on the consequences of breaches or large spills. Second, existing experimental data on LNG spill dynamics and its dispersion over water address spill sizes that are more than a factor of one hundred smaller than spill sizes currently being postulated for some intentional events. Variations in site conditions, LNG ship designs, and environmental conditions further complicate hazard predictions.

The lack of large-scale experimental data forces analysts to make many assumptions and simplifications in calculating the breach of an LNG cargo tank, the resulting spill dispersion, and associated thermal hazards. For example, an evaluation of four recent LNG spill studies (Appendix A) showed significant differences in thermal hazard estimates due to the differences in assumptions and modeling approaches used in each analysis.

Although existing spill assessment and modeling techniques and validation of models against large-scale LNG spill data have limitations, the guidance provided in this report is applicable to performance-based hazard and risk management approaches. Such approaches can be used in conjunction with existing spill and hazard analysis techniques, and safety and security methods, to assess and reduce the risks to both public safety and property caused by an LNG spill over water. Guidance is provided on the use of existing analysis techniques applied to site-specific conditions for increasing confidence in the management of hazards and risks. As additional LNG spill data are obtained and hazard analysis models are improved, they can be incorporated into future risk analysis guidance.

LNG Cargo Tank Breach Analysis

Based on available information, a range of historically credible and potential accidental and intentional events was identified that could cause an LNG cargo tank breach and spill. Modern finite element modeling and explosive shock physics modeling were used to estimate a range of breach sizes for credible accidental and intentional LNG spill events, respectively. The results are discussed in Sections 4 and 5 and detailed in Appendix B.

From these analyses, the sizes of LNG cargo tank breaches for accidents were estimated to be less than 2 m^2. For intentional events, the size of the hole depends on its location on the ship and the source of the threat. Intentional breaches were estimated at 2 to approx. 12 m^2, with nominal sizes of about 5 – 7 m^2. These sizes are smaller than those used in many recent studies. Although smaller, the breach sizes estimated can still lead to large LNG spills.

Using structural fracture mechanics analyses, the potential for cryogenic damage to the LNG ship and other LNG cargo tanks was also evaluated, as discussed in Sections 4 and 5 and Appendix D. Based on these analyses, the potential for cryogenic damage to the ship cannot be ruled out, especially for large spills. The degree and severity of damage depends on the size and location of the breach. Sandia considered cryogenic damage to the ship's structure and concluded that releases from no more than two or three tanks would be involved in a spill that occurs due to any single incident. This cascading release of LNG was analyzed and is not expected to increase significantly the overall fire size or hazard ranges, but the expected fire duration will increase. Hazard analysis and risk prevention and mitigation strategies should consider this in assessing public safety and damage to property.

Spill and Dispersion Analysis

The variability in existing LNG spill and dispersion/thermal hazard modeling approaches is due to physical limitations in the models and the lack of validation with large-scale spill data. Obtaining experimental data for large LNG spills over water would provide needed validation and help reduce modeling uncertainty. Because extrapolation of existing models will be necessary for analysis of potentially large spills, models should be used that invoke as much fundamental physics as possible. Based on the evaluations presented in Sections 4 and 5 and Appendices C and D, several types of models currently exist to assess hazards. Models should be used only where they are appropriate and understood to ensure that the results increase confidence in the analysis of the hazards and risks to public safety and property.

In higher hazard zones, where analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain or structures can occur, modern, CFD models, as listed in Table 2, can be used to improve analysis of site-specific hazards, consequences, and risks. Use of these models is suggested because many of the simpler models have limitations that can cause greater uncertainties in calculating liquid spread, vapor dispersion, and fire hazards. CFD models have their own limitations and should be validated prior to use. Further refinement of CFD models will continue to improve the degree of accuracy and reliability for consequence modeling.

Table 2: Models for Improved Analysis of an LNG Spill in High Hazard Areas

APPLICATION	IMPROVED MODELING APPROACHES
Breach Analysis	Finite element codes for modeling accidental ship collisions & shock physics codes for modeling intentional breaches.
Tank Emptying	Modified orifice model that includes the potential for LNG leakage between hulls.
Structural Damage Modeling	Coupled spill leakage, fluid flow, and fracture mechanics codes for modeling ship structural damage & damage to LNG cargo tanks.
Spreading	CFD codes for modeling spread of cryogenic liquids on water.
Dispersion	CFD codes for modeling dispersion of dense gases.
Fire	CFD codes for modeling fire phenomena, including combustion, soot formation, and radiative heat transfer.

While these studies provide insight into appropriate models to use, additional factors should be considered in applying models to a specific problem. These include model documentation and support, assumptions and limitations, comparison and validation with data, change control and upgrade information, user support, appropriate modeling of the physics of a spill, modeling of the influence of environmental conditions, spill and fire dynamics, and model peer review.

Hazards Analysis and Public Safety Impacts

Current LNG spill and dispersion modeling and analysis techniques have limitations. In addition, variations exist in location-specific conditions that influence dispersion, such as terrain, weather conditions, waves, currents, and the presence of obstacles. Therefore, it is sensible to provide guidance on the general range of hazards for potential spills rather than suggest a specific, maximum hazard guideline.

To assess the general magnitude of expected hazard levels, a limited sensitivity analysis was performed using simplified models for a range of spill volumes. The spill volumes were based on potential breaches from credible accidental and intentional threats. These analyses are summarized in Sections 4 and 5 of this report. While not conducted for a specific site, the analyses provide examples of general considerations for hazards and risks. From the assessment conducted, thermal hazards will occur predominantly within 1600 m of an LNG ship spill, with the highest hazards generally in the near field (approximately 250 - 500 m of a spill). While thermal hazards can exist beyond 1600 m, they are generally lower in most cases.

The general hazard zones and safety guidance identified from this assessment are as follows:

- The pool sizes for the credible spills estimated could range from generally 150 m in diameter for a small, accidental spill to several hundred meters for a large, intentional spill. Therefore, high thermal hazards from a fire are expected to occur within approximately 250 – 500 m from the origin of the spill, depending on the size of the spill. Major injuries and significant structural damage are possible in this zone. The extent of the hazards will depend on the spill size and dispersion from wind, waves, and currents. People, major commercial/industrial areas or other critical infrastructure elements, such as chemical plants, refineries, bridges or tunnels, or national icons located within portions of this zone could be seriously affected.
- Hazards and thermal impacts transition to lower levels with increasing distance from the origin of the spill. Some potential for injuries and property damage can still occur in portions of this zone; but this will vary based on spill size, distance from the spill, and site-specific conditions. For small spills, the hazards transition quickly to lower hazard levels.
- Beyond approximately 750 m for small accidental spills and 1600 m for large spills, the impacts on public safety should generally be low for most potential spills. Hazards will vary; but minor injuries and minor property damage are most likely at these distances. Increased injuries and property damage would be possible if vapor dispersion occurred and a vapor cloud was not ignited until after reaching this distance.

Table 3 summarizes the results on expected hazard levels for several types of accidental and intentional spills. While the analyses included evaluations of the size and number of breaches, spill rate and discharge coefficient, burn rate, surface emissive power, and transmissivity, site-specific environmental conditions such as wind speed, direction, waves, and currents, were not specifically considered. Therefore, the distances to each of the different hazard zones are provided as guidance and will vary depending on site-specific conditions and location.

The upper part of Table 3 identifies the estimated hazard zones in terms of public safety from potential accidents, where spills are generally much smaller. The lower part of Table 3 identifies the estimated hazard zones in terms of public safety from examples of intentional LNG spills, which can be larger.

Table 3: Guidance for Impacts on Public Safety from LNG Breaches and Spills

EVENT	POTENTIAL SHIP DAMAGE AND SPILL	POTENTIAL HAZARD	POTENTIAL IMPACT ON PUBLIC SAFETY*		
			High	Medium	Low
Collisions: Low speed	Minor ship damage, no spill	Minor ship damage	None	None	None
Collisions: High Speed	LNG cargo tank breach and small - medium spill	Damage to ship and small fire	~ 250 m	~ 250 – 750 m	> 750 m
Grounding: <3 m high object	Minor ship damage, no breach	Minor ship damage	None	None	None
Intentional Breach	Intentional breach and medium to large spill	Damage to ship and large fire	~ 500 m	~ 500 m – 1600 m	> 1600 m
	Intentional, large release of LNG	▪ Damage to ship and large fire	~ 500m	~ 500 m – 1600 m	> 1600 m
		▪ Vapor cloud dispersion with late ignition	~ 500 m	> 1600 m	> 2000 m

[a] Distance to spill origin, varies according to site
Low – minor injuries and minor property damage
Medium – potential for injuries and property damage
High – major injuries and significant damage to property

Many of the hazard zones identified in Table 3 are based on thermal hazards from a pool fire, because many of the events will provide ignition sources such that a fire is likely to occur immediately. In some cases, the potential exists for a vapor cloud to be created without being ignited. As noted in Sections 4 and 5 and Appendices C and D, a vapor cloud from an LNG spill could extend to 2,500 m, if an ignition source is not available. The potential thermal hazards within a vapor cloud could be high. Because vapor cloud dispersion is highly influenced by atmospheric conditions, hazards from this type of event will be very site-specific.

In addition, latent or indirect effects, such as additional damage that could be caused by a damaged infrastructure (e.g. a refinery or power plant), were not directly assessed. These types of issues and concerns are site-specific and should be included as part of the overall risk management process.

1.2 Safety Analysis Conclusions

The potential for damage to LNG containment systems that could result from accidents or intentional events was evaluated. While hazard distances and levels will vary based on site-specific conditions, a summary of the safety analysis conclusions is presented below.

1.2.1 General Conclusions

1. The most significant impacts to public safety and property exist within approximately 500 m of a spill, with much lower impacts at distances beyond 1600 m, even for very large spills.
2. Under certain conditions, it is possible that multiple LNG cargo tanks could be breached as a result of the breaching event itself, as a consequence of LNG-induced cryogenic damage to nearby tanks, or from fire-induced structural damage to the vessel.
3. Multiple breach and cascading LNG cargo tank damage scenarios were analyzed, as discussed in Sections 4 and 5. While possible under certain conditions, they are likely to involve no more than two to three cargo tanks at any one time. These conditions will not greatly change the hazard ranges noted in General Conclusion Number 1, but will increase expected fire duration.

1.2.2 Accidental Breach Scenario Conclusions

1. Accidental LNG cargo tank damage scenarios exist that could potentially cause an effective breach area of 0.5 to 1.5 m^2.
2. Due to existing design and equipment requirements for LNG carriers, and the implementation of navigational safety measures such as traffic management schemes and safety zones, the risk from accidents is generally low.
3. The most significant impacts to public safety and property from an accidental spill exist within approximately 250 m of a spill, with lower impacts at distances beyond approximately 750 m from a spill.

1.2.3 Intentional Breach Scenario Conclusions

1. Several credible, intentional LNG cargo tank damage scenarios were identified that could initiate a breach of between 2 m^2 to approximately 12 m^2, with a probable nominal size of 5 – 7 m^2.
2. Most of the intentional damage scenarios identified produce an ignition source and an LNG fire is very likely to occur.
3. Some intentional damage scenarios could result in vapor cloud dispersion, with delayed ignition and a fire.
4. Several intentional damage scenarios could affect the structural integrity of the vessel or other LNG cargo tanks due to ignition of LNG vapor trapped within the vessel. While possible under certain conditions, these scenarios are likely to involve no more than two to three cargo tanks at any one time, as discussed in Sections 4 and 5.
5. Rapid phase transitions (RPT) are possible for large spills. Effects will be localized near the spill source and should not cause extensive structural damage.
6. The potential damage from spills to critical infrastructure elements such as bridges, tunnels, industrial/commercial centers, LNG unloading terminals and platforms, harbors, or populated areas can be significant in high hazard zones.

7. In general, the most significant impacts on public safety and property from an intentional spill exist within approximately 500 m of a spill, with lower impacts at distances beyond approximately 1600 m from a spill, even for very large spills.

1.3 Guidance on Risk Management for LNG Operations over Water

Risk identification and risk management processes should be conducted in cooperation with appropriate stakeholders, including public safety officials and elected public officials. Considerations should include site-specific conditions, available intelligence, threat assessments, safety and security operations, and available resources. This approach should be performance-based and include identification of hazards and risks, protection required for public safety and property, and risk prevention and mitigation strategies.

The following guidance is provided to assist risk management professionals, emergency management and public safety officials, port security officials and other appropriate stakeholders in developing and implementing risk management strategies and processes. For both accidental and intentional spills, the following is recommended:

- Use effective security and protection operations that include enhanced interdiction, detection, delay procedures, risk management procedures, and coordinated emergency response measures, which can reduce the risks from a breaching event;
- Implement risk management strategies based on site-specific conditions and the expected impact of a spill on public safety and property. Less intensive strategies would often be sufficient in areas where the impacts of a spill are low.
- Where analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain or structures can occur, modern, validated computational fluid dynamics (CFD) models can be used to improve analysis of site-specific hazards.

1.3.1 Guidance on Risk Management for Accidental LNG Spills

Zone 1

These are areas in which LNG shipments transit narrow harbors or channels, pass under major bridges or over tunnels, or come within approximately 250 meters of people and major infrastructure elements, such as military facilities, population and commercial centers, or national icons. Within this zone, the risk and consequences of an accidental LNG spill could be significant and have severe negative impacts. Thermal radiation poses a severe public safety and property hazard, and can damage or significantly disrupt critical infrastructure located in this area.

Risk management strategies for LNG operations should address both vapor dispersion and fire hazards. Therefore, the most rigorous deterrent measures, such as vessel security zones, waterway traffic management, and establishment of positive control over vessels are options to be considered as elements of the risk management process. Coordination among all port security stakeholders is essential. Incident management and emergency response measures should be carefully evaluated to ensure adequate resources (i.e., firefighting, salvage, etc.) are available for consequence and risk mitigation.

Zone 2

These are areas in which LNG shipments and deliveries occur in broader channels or large outer harbors, or within approximately 250 m – 750 m of major critical infrastructure elements like population or commercial centers. Thermal radiation transitions to less severe hazard levels to public safety and property. Within Zone 2, the consequences of an accidental LNG spill are reduced and risk reduction and mitigation approaches and strategies can be less extensive.

Within Zone 2, the consequences of an accidental LNG spill are reduced and risk reduction and mitigation approaches and strategies can be less extensive. In this zone, risk management strategies for LNG operations should focus on approaches dealing with both vapor dispersion and fire hazards. The strategies should include incident management and emergency response measures such as ensuring areas of refuge (e.g. enclosed areas, buildings) are available, development of community warning signals, and community education programs to ensure persons know what precautions to take.

Zone 3

This zone covers LNG shipments and deliveries that occur more than approximately 750 m from major infrastructures, population/commercial centers, or in large bays or open water, where the risks and consequences to people and property of an accidental LNG spill over water are minimal. Thermal radiation poses minimal risks to public safety and property.

Within Zone 3, risk reduction and mitigation strategies can be significantly less complicated or extensive. Risk management strategies should concentrate on incident management and emergency response measures that are focused on dealing with vapor cloud dispersion. Measures should ensure areas of refuge are available, and community education programs should be implemented to ensure that persons know what to do in the unlikely event of a vapor cloud.

1.3.2 Guidance on Risk Management for Intentional LNG Spills

Zone 1

These are areas in which LNG shipments occur in narrow harbors or channels, pass under major bridges or over tunnels, or come within approximately 500 meters of major infrastructure elements, such as military facilities, population and commercial centers, or national icons. Within this zone, the risk and consequences of a large LNG spill could be significant and have severe negative impacts. Thermal radiation poses a severe public safety and property hazard, and can damage or significantly disrupt critical infrastructure located in this area.

Risk management strategies for LNG operations should address vapor dispersion and fire hazards. The most rigorous deterrent measures, such as vessel security zones, waterway traffic management, and establishment of positive control over vessels are elements of the risk management process. Coordination among all port security stakeholders is essential. Incident management and emergency response measures should be carefully evaluated to ensure adequate resources (i.e., firefighting, salvage) are available for consequence and risk mitigation.

Zone 2

These are areas in which LNG shipments and deliveries occur in broader channels or large outer harbors, within approximately 500 m – 1.6 km of major critical infrastructure elements, such as population or commercial centers. Within Zone 2, the consequences of even a large LNG spill are reduced. Thermal radiation transitions to less severe hazard levels to public safety and property.

Risk management strategies for LNG operations that occur in this zone should focus on vapor dispersion and fire hazards. The strategies should include incident management and emergency response measures that ensure areas of refuge (enclosed areas, buildings) are available, the development of community warning procedures, and education programs to ensure that communities are aware of precautionary measures.

Zone 3

This zone covers LNG shipments and deliveries that occur more than approximately 1.6 km from major infrastructures, population/commercial centers, or in large bays or open water, where the risks and consequences to people and property of a large LNG spill over water are minimal. Thermal radiation poses minimal risks to public safety and property.

Risk reduction and mitigation strategies can be significantly less complicated or extensive than Zones 1 and 2. Risk management strategies should concentrate on incident management and emergency response measures for dealing with vapor cloud dispersion. Measures should ensure that areas of refuge are available, and community education programs should be implemented to ensure that persons know what to do in the unlikely event of a vapor cloud.

2 BACKGROUND

Many studies have been conducted to assess the consequences and risks of LNG spills from both storage terminals and LNG tankers. However, while recognized standards exist for the systematic safety analysis of potential spills or releases from LNG storage terminals and facilities on land, no equivalent set of standards exists for the evaluation of the safety or consequences from LNG tanker spills over water. Since the incidents surrounding September 11, 2001, much larger spill scenarios and their potential consequences are being evaluated for many types of flammable cargo transportation, including LNG tankers.

Due to limited experience and experimental testing associated with large-scale spills over water, most studies use simplifying assumptions to calculate and predict the hazards of a large LNG spill. The range of assumptions and estimates for many complicated spill scenarios can lead to significant variability in estimating the probability, hazards, consequences, and overall risks of large LNG spills over water.

To address these issues, DOE requested that Sandia help to quantify potential credible threats to an LNG ship, assess the potential hazards and consequences from an LNG spill, and identify potential prevention and mitigation strategies that could be implemented to reduce the risks of a potentially large LNG spill over water. These efforts included:

- An in-depth literature search of the experimental and technical studies associated with evaluating the safety and hazards of LNG following a major spill from an LNG ship;
- A detailed review of four recent LNG spill modeling studies related to the safety implications of a large-scale LNG spill over water;
- Evaluation of potential scenarios for breaching an LNG cargo tank, both accidentally and intentionally, identification of the potential size of an LNG spill for those scenarios, and an assessment of the potential range of hazards and consequences from the spills; and
- Development of a risk analysis approach to quantify threats, assess hazards, and identify operational, safety, and security procedures and techniques to reduce to acceptable levels the probability, risks, and hazards of a large LNG spill over water.

To support its efforts, Sandia worked with the U.S. DOE, the U.S. Coast Guard, LNG industry and ship management agencies, LNG shipping consultants, and government intelligence agencies to collect background information on LNG ship and cargo tank designs, accident and threat scenarios, and standard LNG ship safety and risk management operations. The information gathered was used to develop accidental and intentional LNG cargo tank breach scenarios, for modeling of potential spill hazards, and as the basis for analysis to determine the extent and severity of LNG spill consequences. Based on analysis of the modeling results, three consequence-based hazard zones were identified and risk reduction and mitigation techniques were identified to reduce impacts on public safety and property.

The results of these evaluations are summarized in Sections 3 – 6 and detailed analyses are presented in Appendices A – D.

2.1 History and Description of LNG

Natural gas liquefaction dates back to the 19th century, when British chemist and physicist Michael Faraday experimented with liquefying different types of gases, including natural gas. A prototype LNG plant was first built in West Virginia in 1912, and the first commercial liquefaction plant was built in Cleveland, Ohio, in 1941. The Cleveland plant liquefied natural gas and stored the LNG in tanks, which was vaporized later for use during heavy demand periods. Natural gas continues to be liquefied and stored for use during peak demands, with almost 100 LNG peaking facilities in the U.S. [EIA 2002].

2.1.1 Grow th of International LNG Transportation

In January 1959, the world's first LNG tanker, *The Methane Pioneer,* a converted World War II liberty freighter, carried an LNG cargo from Lake Charles, Louisiana to the United Kingdom. The U.S. began exporting LNG to Asia in 1969, when Phillips Petroleum built a liquefaction facility on the Kenai Peninsula, about 100 miles south of Anchorage, Alaska. The Phillips plant continues to operate and is one of the oldest continuously operated LNG plants in the world.

A fleet of about 150 specially designed LNG ships is currently being used to transport natural gas around the globe. Worldwide, there are 17 LNG export (liquefaction) terminals and 40 import (re-gasification) terminals. This commercial network handles approximately 120 million tons of LNG every year. LNG carriers often travel through areas of dense traffic. In 2000, for example, Tokyo Bay averaged one LNG cargo every 20 hours and one cargo per week entered Boston harbor. Estimates are that world wide LNG trade will increase 35% by 2020. The major areas for increased LNG imports are Europe, North America, and Asia [Kaplan and Marshal 2003] [DOE 2003].

Four LNG marine terminals were built in the United States between 1971 and 1980: Lake Charles, Louisiana; Everett, Massachusetts; Elba Island, Georgia; and Cove Point, Maryland. After reaching a peak receipt volume of four million tons in 1979, LNG imports declined when de-control of natural gas prices produced an economic supply of natural gas within U.S. borders. The Elba Island and Cove Point receiving terminals were mothballed in 1980. Due to the recent growth in natural gas demand, both of these terminals have undergone refurbishment and reactivation, and both are currently receiving LNG shipments. The Lake Charles and Everett terminals, which have operated below design capacity for many years, have also recently increased receipt of LNG.

Import of natural gas into the U.S. is expected to double over the next 20 years [DOE 2003]. Four to eight new LNG terminals are expected to be constructed in the next four to five years and more than 40 new terminal sites are under consideration and investigation. A factor in the siting of LNG receiving terminals is the proximity to market. Therefore, terminals are being considered in areas with high natural gas demands, which includes locations on all three U.S. coasts. Most are being planned to handle one to two LNG tanker shipments per week.

2.1.2 LNG Transportation by Ship

Specially designed ships are used to transport LNG to U.S. import terminals [Harper 2002] [OTA 1977]. Many LNG tankers currently in service use Moss spherical tanks, as illustrated in Figure 1. Moss tankers sometimes use nitrogen to purge some below-decks spaces to aid in preventing fires. Moss ship holds are designed to collect spilled LNG and the vessels contain equipment required to recover it [Glasfeld 1980]. In addition to Moss tankers, other LNG ships are designed with prismatic, membrane-lined cargo tanks.

Figure 1. Moss-Spherical LNG Tanker Ship

Figure 2. Prismatic Tanker Ship

Prismatic tanks are designed to conform to the shape of the ship's hull, thus occupying much of the internal area of the ship, which minimizes areas into which LNG from a tank rupture or spill can be diverted.

Some of the special features of LNG ships include:

- Construction of specialized materials and equipped with systems designed to safely store LNG at temperatures of -260 °F (-162.2°C).
- All LNG ships are constructed with double hulls. This construction method not only increases the integrity of the hull system but also provides additional protection for the cargo tanks in the event of an accidental collision.
- Coast Guard regulations and the "International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk" (International Gas Carrier Code) require that LNG ships meet a Type IIG standard, which is an intermediate-level safety design standard for hazardous cargoes that includes direction on double-hull designs and materials, subdivision, damage stability, and cargo tank location.

During the past 40 years, more than 80,000 LNG carrier voyages have taken place, covering more than 100 million miles, without major accidents or safety problems, either in port or on the high seas [Pitblado 2004]. Over the life of the industry, eight marine incidents worldwide have resulted in LNG spills, with some damage; but no cargo fires have occurred. Seven incidents have been reported with ship structural damage, two from groundings; but no spills were recorded. No LNG shipboard fatalities from spills have occurred [Beard 1982] [SIGTTO 2003].

2.1.3 LNG Properties

Typical properties of LNG:

- LNG is simply natural gas that has been cooled to its liquid state at atmospheric pressure: -260°F (-162.2°C) and 14.7 psia. Currently, imported LNG is commonly 95% – 97% methane, with the remainder a combination of ethane, propane, and other heavier gases.
- LNG is transported at ambient pressures.
- Liquefying natural gas vapor, which reduces the gas into a practical size for transportation and storage, reduces the volume that the gas occupies more than 600 times.
- LNG is considered a flammable liquid.
- LNG vapor is colorless, odorless, and non-toxic.
- LNG vapor typically appears as a visible white cloud, because its cold temperature condenses water vapor present in the atmosphere.
- The lower and upper flammability limits of methane are 5.5% and 14% by volume at a temperature of 25°C.

Table 4 lists the flammability limits for several compounds.

Table 4: Flammability Limits for Selected Fuel Compounds at 25°C

FUEL	LOWER FLAMMABILITY LIMIT (LFL) % by volume in air	UPPER FLAMMABILITY LIMIT (UFL) % by volume in air
Methane	5.5	14.0
Butane	1.6	8.4
Propane	2.1	9.6
Ethanol	3.3	19.0
Gasoline (100 Octane)	1.4	7.8
Isopropyl alcohol	2.0	12.7
Ethyl ether	1.9	36.0
Xylene	0.9	7.0
Toluene	1.0	7.1
Hydrogen	4.0	75.0
Acetylene	2.5	85.0

2.2 Growing Interest in LNG Safety and Security

The increasing demand for natural gas will significantly increase the number and frequency of LNG tanker deliveries to ports across the U.S. Because of the increasing number of shipments, concerns about the potential for an accidental spill or release of LNG have increased. In addition, since the incidents surrounding September 11, 2001, concerns have increased over the impact that an attack on hazardous or flammable cargoes, such as those carried by LNG ships, could have on public safety and property.

The risks and hazards from an LNG spill will vary depending on the size of the spill, environmental conditions, and the site at which the spill occurs. Hazards can include cryogenic burns to the ship's crew and people nearby or potential damage to the LNG ship from contact with the cryogenic LNG. Vaporization of the liquid LNG can occur once a spill occurs and subsequent ignition of the vapor cloud could cause fires and overpressures that could injure people or cause damage to the tanker's structure, other LNG tanks, or nearby structures.

With the growing dependence on imported LNG to meet increasing U.S. natural gas demands, damage or disruption from a spill to an LNG import terminal or harbor facilities could curtail LNG deliveries and impact natural gas supplies. Therefore, methods to ensure the safety, security, and reliability of current or future LNG terminals and LNG shipments are important from both public safety and property perspectives, as well as from a regional, energy reliability standpoint. Methods to reduce the risks and hazards from a potential LNG spill must be considered on a site-specific basis and will vary, depending on factors such as location, geography, operational considerations, and weather conditions. The next section discusses the process used to assess LNG tanker safety and security from accidental and intentional events, improve overall protection, and reduce impacts on public safety and property.

3 RISK ASSESSMENT OF LNG SPILLS OVER WATER

High consequence operations such as the transportation, off-loading, and storage of LNG imply potential risks to people and property. Risk is defined as the potential for suffering harm or loss and is often quantified as the product of the probability of occurrence of a threatening event times the system vulnerability to that event and the consequences of that event. Thus,

Risk = $\mathbf{P_t}$ (threat occurring) x $\mathbf{P_s}$ (system failure/threat) x **Consequences**;

Where: $\mathbf{P_t}$ = the probability of an accidental or intentional threat,

$\mathbf{P_s}$ = the probability that preventive or mitigating measures fail, and

Consequences = usually expressed in fatalities or costs.

Effectively evaluating the risks of a large LNG spill over water requires that the potential hazards (results of events that are harmful to the public and/or property) and consequences be considered in conjunction with the probability of an event, plus the effectiveness of physical and operational measures of LNG transportation to prevent or mitigate a threatening event. For example, safety equipment, operational considerations and requirements, and risk management planning can work together to reduce the risks of an LNG spill by reducing both the probability of an event that could breach the LNG tanker and by reducing the consequences of a spill.

Because of the difficulty in assessing the effectiveness of ship safety measures and operational safety and security strategies, many studies assume the probability of an event and a ship's vulnerability to be one; therefore, the concentration is on calculating expected consequences. This often provides worst-case results with low probability and very high uncertainty, which can inappropriately drive operational decisions and system designs. Therefore, for high consequence and low probability events, a performance-based approach is often used for developing risk management strategies that will reduce the hazards and risks to both public safety and property.

3.1 Risk Analysis Elements of a Potential LNG Spill

The risk analysis approach of a potential LNG spill should include:

1. **Uncertainty:** Assessment of the accuracy of the assumptions used and the probable ranges.
2. **Comprehensiveness:** Do the failure modes considered account for all major avenues of loss? Understanding the full range of consequences associated with a catastrophe can require considerable effort. Completeness is important to properly support risk assessment and risk management.

   Two important variables are 'directness of effect' and 'latency.' For example, if an explosion breaches an LNG cargo tank on a ship, that is a direct effect. Conversely, if a resulting explosion damages an LNG terminal—hampering future LNG deliveries for extended periods—that is an indirect or latent effect. Latency refers to when the effects are felt. Immediate effects occur simultaneously with the threat; whereas latent effects occur after an interval, the length of which might vary from system to system. It should be emphasized that indirect/latent effects sometimes dominate other consequences.

3. **Evaluation of risk reduction measures:** One way to reduce risk is to remove or block the threat; i.e., prevent the disaster from occurring in the first place. For example, reinforce ships against collisions or reduce ship speeds in a harbor to reduce the chance of a spill.

4. **Threat as a moving target:** Many avenues to failure — mechanical, environmental insult, operator error — are amenable to analysis and can be confidently predicted to occur with some probability in the future. Other types of threats can be constantly changing and difficult to assess accurately, requiring more robust approaches for prevention or mitigation and frequent re-evaluations of new threats.

3.2 LNG Spill Risk Assessment and Management Process

A general performance-based risk assessment and risk management process is shown schematically in Figure 3. The risk analysis, in turn, helps support a program for managing risks of LNG deliveries to terminals for site-specific locations and conditions. The risk assessment and management process includes:

- Evaluating the potential for an event that could cause a breach or loss of LNG from a ship;
- Establishing the potential damage to a cargo tank or other system from these events and the potential spills that could occur;
- Estimating the volume and rate of a potential LNG spill based on the dimensions and location of the breach, properties and characteristics of the LNG, ship construction and design, and environmental conditions (e.g., wind, waves, currents, etc.);
- Estimating the dispersion, volatilization, and potential hazards of a spill based on physical and environmental conditions; and
- When necessary, identifying prevention and mitigation approaches and strategies to meet risk management goals.

As illustrated in Figure 3, if risks, costs, or operational impacts are deemed to be too high, the overall process cycles back through the evaluation to identify alternative approaches for improving system performance. Safeguards could include a range of risk management options: improvements in ship protection, modification of existing operational and safety and security management procedures, improvements in emergency response coordination, or changes in support operations or services. The risks are then re-evaluated according to the new approaches to determine if they meet identified risk management goals. If not, then the evaluations can be repeated with additional provisions or changes until the risk management goals are reached. The potential alternatives, changes, and/or upgrades can be compared through the process to identify appropriate and effective approaches for improving overall system safety and security.

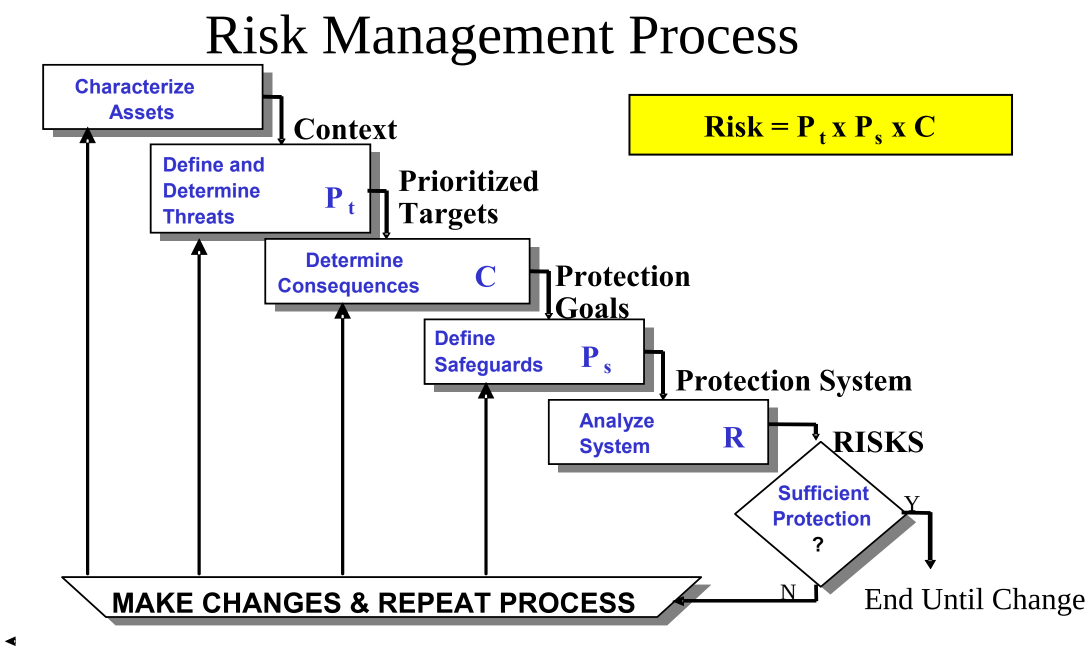


Figure 3. Risk Assessment and Risk Management Approach

Deciding on the sufficiency of protection measures to meet risk management goals is often aided by a benefit-cost evaluation. In most locations and most operations, some level of risk is common and, therefore, a "residual" risk often remains. For example, certain levels of safety equipment are standard features in automobiles, such as seat belts, air bags, and antilock brakes. While they might be effective safety measures, they do not provide total protection in all automobile accident scenarios. Therefore, the public does have some level of risk associated with driving.

How might risk management considerations apply to LNG transportation and off-loading? Table 5 illustrates some examples of potential LNG transportation safeguards and associated impacts on overall effectiveness, cost, operations, and residual risks.

Table 5: Examples of Potential LNG Transportation Safeguards and Impacts

SAFEGUARD ACTION	RISK REDUCTION	RESIDUAL RISKS	CONSEQUENCE IMPROVEMENT	COST OF SAFEGUARD APPROACH	OPERATIONAL IMPACTS
Smaller LNG tankers	Potential smaller fire size and shorter fire duration	Thermal hazards from small fire, higher accident potential with increased shipments	potential reduction in hazard zone and reduced impacts on public safety and property	Increased shipping costs, increased energy costs	Increased number of shipments, additional port disruption
Evacuation during LNG shipments	Reduce hazards to people from potential spill	Hazards to property from a fire, accidents during evacuation	Reduce injuries and deaths from potential fire	Labor intensive, increased costs for emergency services	Disruption of evacuees
Remote terminal and pipeline	Reduce impacts on public safety and property from potential fire	Impact on public safety and property from potential pipeline leaks	potential reduction in hazards from large-scale or catastrophic fire	potential high capital costs, increased energy costs	Pipeline vulnerability issues

While many potential safeguards might be identified for a given location, the level of risk reduction and risk management required to be protective of public safety and property for LNG transportation will vary based on site-specific conditions. The risk management goals for a given location should be determined in cooperation with all stakeholders. Stakeholders include the general public, public safety officials and elected officials, facility operators, port and transportation safety and security officials, underwriters, utility representatives, regulatory agencies, and ship management companies.

3.3 The Elements of an LNG Spill over Water

The detailed flowchart ('event tree') in Figure 4 illustrates an overview of event sequences that might ensue following a breach of an LNG cargo tank and /or a spill. The purpose of the flowchart is to provide a basis for a comprehensive risk analysis. In the event tree, time progresses roughly from left to right, beginning with a potential breach or damage of an LNG cargo tank or LNG handling system; progressing to an LNG spill, dispersion, and energy release; ending with an analysis of impacts on people and property. The event tree approach helps ensure that all credible events are considered systematically and helps identify critical elements in the event sequence. This aids in focusing risk management efforts on the most important elements, and improving both public safety and security more efficiently and cost-effectively. As shown in the event tree, the hazards and consequences from potential spills can vary.

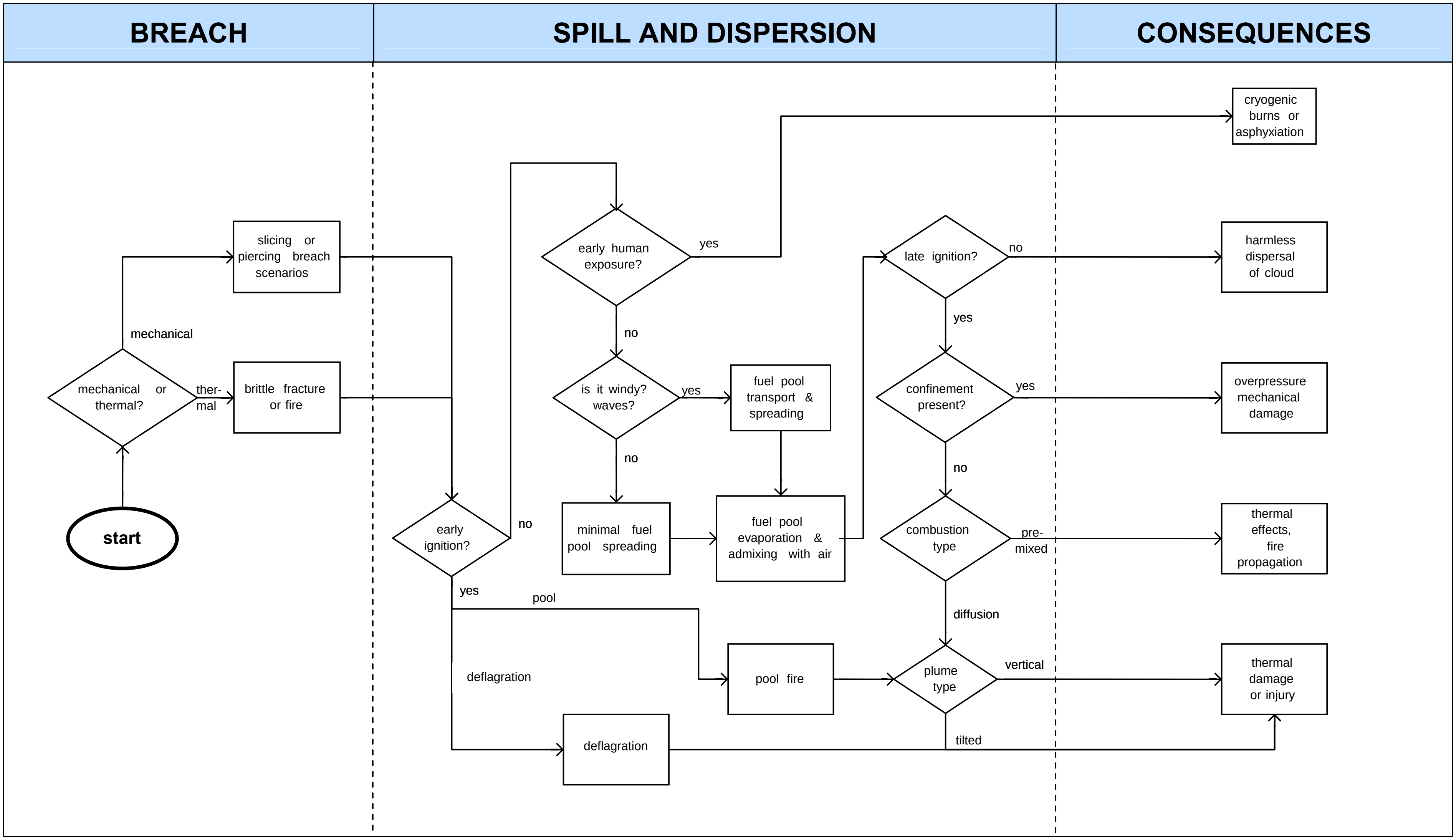


Figure 4. Potential Sequences of Events Following a Breach of an LNG cargo tank

3.3.1 LNG Cargo Tank Breaches

The variables that influence an LNG cargo tank breach include:

- Type and location of the breach and the energy involved,
- The vessel's geometry, its construction and materials, hold spaces, distance between hulls, tonnage, and event mitigation systems;
- LNG cargo tank construction and size; and
- The fluid mechanics and thermodynamic characteristics of LNG.

Figure 5 illustrates a breach and subsequent spill involving a Moss tanker. If the cargo tank is punctured, LNG driven only by weight of the fluid itself will traverse the ship's below-decks spaces plus the ballast space between the two hulls, which are empty when a full cargo is on board [Kaplan and Marshall 2003]. The speed at which an LNG spill will progress will depend on the size and location of the breach in the LNG cargo tank.

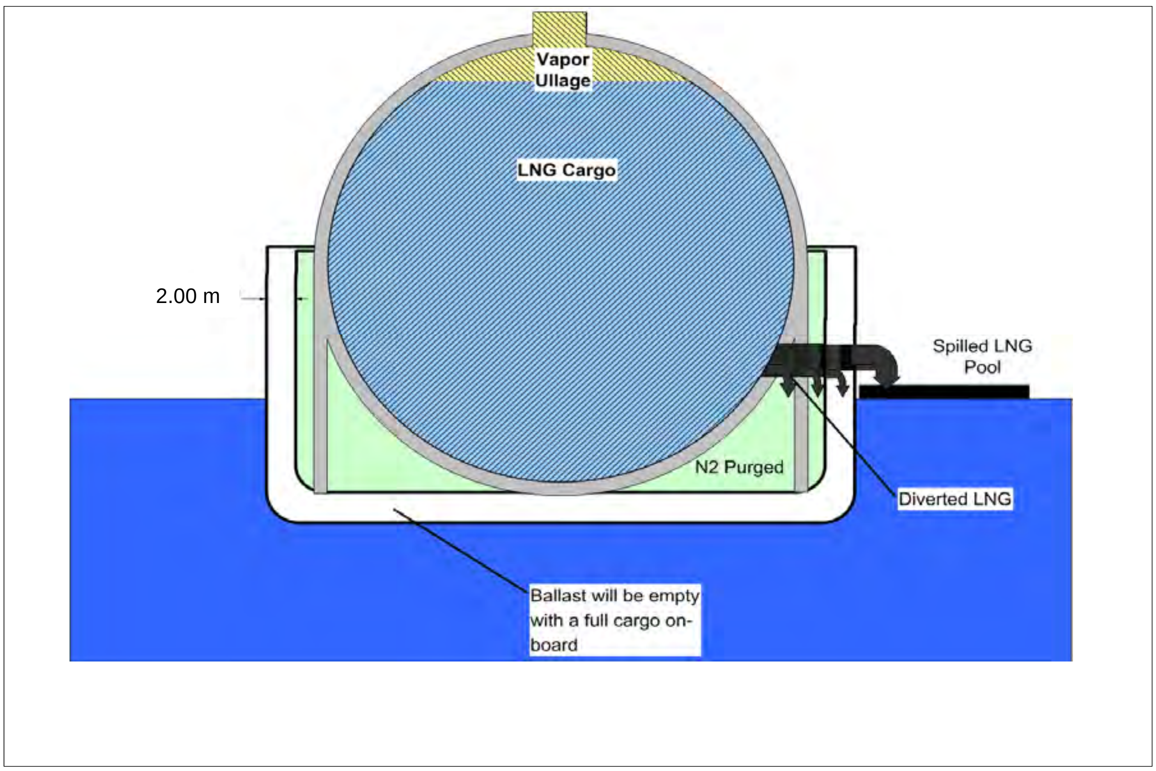


Figure 5. Anatomy of an LNG Spill on Water

For LNG cargo tank designs, a realistic estimate of tanker losses (i.e., the fraction of the spill that reaches the water) must be reduced to account for LNG diverted to the ballast space or, for the Moss spherical design, vacant hold areas. Spill damage to the ship from contact with the cryogenic LNG and/or from fire damage to the ship or its other LNG cargo tanks are consequences that were considered during this study. Based on the analyses, the potential for damage to the ship cannot be ruled out, especially for large spills. However, it was concluded that releases from no more than two or three tanks would be involved in a spill at any one time. This cascading release is not expected to increase significantly the overall fire size or hazard ranges, but the expected fire duration would increase.

The potential size and impact from several breaching scenarios from both accidental and intentional events were evaluated and are summarized in Sections 4 and 5 and discussed in detail in Appendix B – *Threat Analysis and Spill Probabilit*y.

3.3.2 LNG Spill Dispersion after a Breach

Quantifying the size and likelihood of spills from different events drives the *Spill and Dispersion* part of the event tree. Following a tank breach or other spill event, depending on the size and location, LNG can be expected to spill onto or into the LNG ship itself, escape through a breach onto the water surface, or both. Depending on whether there is early or late ignition, LNG dispersion can occur through either volatilization of the LNG into the air and transport as a vapor cloud or transport as a liquid on the surface of the water.

Several variables must be addressed in developing an assessment of an LNG spill and its general dispersion, including potential ignition sources and ignition times. These factors determine whether the LNG disperses without a fire, burns as a pool fire, or burns as a vapor fire. Assumptions made in addressing or analyzing these variables can have a significant impact on estimates of the potential hazards associated with an LNG spill. The experimental results from a wide range of spill and dispersion testing were evaluated and the expected impacts of large-scale spills over water were evaluated. They are summarized in Sections 4 and 5 and discussed in detail in Appendix C – *LNG Spill and Dispersion Analysis*.

3.3.3 Potential Consequences from an LNG Spill over Water

The consequences or hazards from an LNG spill include a wide range of potential events, as illustrated in the event tree. The sections below discuss the analyses that should be considered in a study attempting to assess the consequences and hazards of an LNG spill for a specific site. The potential hazards and their results were reviewed and evaluated and are summarized in Sections 4 and 5, and discussed in detail in Appendix C – *LNG Spill and Dispersion Analysis* and Appendix D – *Spill Consequence Analysis*.

Asphyxiation

Methane is considered a simple asphyxiant, but has low toxicity to humans. In a large-scale LNG release, the cryogenically cooled liquid LNG would begin to vaporize upon release from the breach of an LNG cargo tank. If the vaporizing LNG does not ignite, the potential exists that the LNG vapor concentrations in the air might be high enough to present an asphyxiation hazard to the ship crew, pilot boat crews, emergency response personnel, or others that might be exposed to an expanding LNG vaporization plume. Although oxygen deficiency from vaporization of an LNG spill should be considered in evaluating potential consequences, this should not be a major issue because flammability limits and fire concerns will probably be the dominant effects in most locations.

Cryogenic Burns and Structural Damage

The very low temperature of LNG suggests that a breach of an LNG cargo tank that could cause the loss of a large volume of liquid LNG might have negative impacts on people and property near the spill, including crewmembers or emergency personnel. If LNG liquid contacts the skin, it can cause cryogenic burns.

Potential degradation of the structural integrity of an LNG ship could occur, because LNG can have a very damaging impact on the integrity of many steels and common ship structural connections, such as welds. Both the ship itself and other LNG cargo tanks could be damaged from a large spill.

Combustion and Thermal Damage

In general, combustion resulting from industrial incidents such as an LNG spill can result in thermal and/or pressure loading. Thermal loads are very dependent on the rate of energy conversion ('heat release rate'). Pressure loads are very dependent on the power density; that is, the heat release rate per unit volume. Thus, how combustion occurs is as important to the consequences of a spill as is the energy available. Table 6 shows the general type of thermal radiation damage from a fire. These levels are often used to establish fire hazard areas.

Table 6: Common, Approximate Thermal Radiation Damage Levels

Incident Heat Flux (kW/m^2)*	Type of Damage
35 – 37.5	Damage to process equipment including steel tanks, chemical process equipment, or machinery
25	Minimum energy to ignite wood at indefinitely long exposure without a flame
18 – 20	Exposed plastic cable insulation degrades
12.5 – 15	Minimum energy to ignite wood with a flame; melts plastic tubing
5	Permissible level for emergency operations lasting several minutes with appropriate clothing

*Based on an average 10 minute exposure time
[Barry 2002]

For example, the National Fire Protection Association standard for the production, storage, and handling of Liquefied Natural Gas (Standard 59A) recommends that an incident heat flux value of 5 kW/m^2 be the design level that should not be exceeded at a property line or in areas where groups of more than 50 people might assemble [NFPA 2001]. Therefore, 5 kW/m^2 is a commonly used value for establishing fire protection distances for people. While structures might be able to withstand higher levels of incident heat flux, as shown in Table 6, heat flux levels approaching 35 kW/m^2 will cause significant damage to structures, equipment, and machinery.

Generally, combustion of LNG vapor is controlled by two limiting factors: 1) whether the LNG vapor does not have enough time to mix with the air (called non-pre-mixed combustion), and 2) whether the ignition occurs after the fuel has time to mix with the surrounding air (appropriately called 'pre-mixed combustion'). Therefore, ignition time is important in spill scenarios to assess appropriately the type and extent of thermal radiation from an LNG spill and fire. As noted in Table 6, combustion and thermal damage from a fire can have severe consequences and should be carefully and thoroughly analyzed.

LNG/Fireballs

Two types of combustion modes might produce damaging pressure: 'deflagration' and 'detonation'. Deflagration is a rapid combustion that progresses through an unburned fuel-air mixture at subsonic velocities; whereas, detonation is an extremely rapid combustion that progresses through an unburned fuel-air mixture at supersonic velocities. For low reactivity fuels such as natural gas, combustion will usually progress at low velocities and will not generate significant overpressure under normal conditions. Ignition of a vapor cloud will cause the vapor to burn back to the spill source. This is generally referred to as a 'fireball', which, by its nature, generates relatively low pressures, thus having a low potential for pressure damage to structures.

LNG/Air Explosions

Certain conditions, however, might cause an increase in burn rate that does result in overpressure. If the fuel-air cloud is confined (e.g., trapped between ship hulls), is very turbulent as it progresses through or around obstacles, or encounters a high-pressure ignition source, a rapid acceleration in burn rate might occur [Benedick et al. 1987]. The potential for damaging overpressures from such events could occur under some limited spill and dispersion scenarios, specifically in confined areas. However, effects will be localized near the spill source and are not expected to cause extensive structural damage.

Rapid Phase Transitions (RPT)

Rapid Phase Transitions occur when the temperature difference between a hot liquid and a cold liquid is sufficient to drive the cold liquid rapidly to its superheat limit, resulting in spontaneous and explosive boiling of the cold liquid. When a cryogenic liquid such as LNG is suddenly heated by contacting a warm liquid such as water, explosive boiling of the LNG can occur, resulting in localized overpressure releases. Energy releases equivalent to several kilograms of high explosive have been observed. The impacts of this phenomenon will be localized near the spill source and should not cause extensive structural damage.

3.4 Evaluation of Four Recent LNG Spill Modeling Studies

Four recent LNG spill-modeling studies were evaluated to assess whether they provide a definitive determination of the lateral extent and thermal hazards of a large-scale release of LNG over water. The results of the comparisons are summarized below and detailed in Appendix A. The studies reviewed include:

- "Comparison of Hypothetical LNG and Fuel Oil Fires on Water." Report by the National Oceanic and Atmospheric Administration (NOAA), Office of Response and Restoration, Seattle, WA, 2003, DRAFT [Lehr and Simicek-Beatty 2003].
- "Model of spills and fires from LNG and oil tankers." Journal of Hazardous Materials, B96-2003, 171-188, 2003 [Fay 2003].
- "Modeling LNG Spills in Boston Harbor." Copyright© 2003 Quest Consultants, Inc., 908 26th Ave N.W., Norman, OK 73609; Letter from Quest Consultants to DOE

(October 2, 2001); Letter from Quest Consultants to DOE (October 3, 2001); and Letter from Quest Consultants to DOE (November 17, 2003) [Quest 2003].

- "Liquefied Natural Gas in Vallejo: Health and Safety Issues." LNG Health and Safety Committee of the Disaster Council of the City of Vallejo, CA, January 2003 [Vallejo 2003] [Koopman 2004].

An event tree of generic LNG spill scenarios was used to compare and contrast the analysis process in each study. Table 7 summarizes and illustrates the range of assumptions employed in each of the four studies for evaluating a potential LNG cargo tank breach plus an associated fuel spill, its spread and dispersion, and fuel ignition and burning. All the studies assumed ignition such that the fuel burns as a pool fire, with no explosions.

Table 7: Summary of Assumptions in the Four Studies Analyzed

STUDY	TIME TO EMPTY (Min)	VAPORIZES DURING SPREAD	EFFECT OF WAVES INCLUDED	POOL SHAPE	IGNITION TIME	FLAME MODEL	COMBUSTION MODE	IGNITION AT POOL; NOT IN VAPOR CLOUD
Lehr	Instantly	Yes	No	Circle	Instantly	Solid cylinder	Diffusion flame with no explosion	Yes
Fay	Varies with hole size	Yes	No	Semicircle	Instantly	Point source	Diffusion flame with no explosion	Yes
Quest	2	Yes	Yes	Circle	Instantly after spread	Solid cylinder that includes tilt for wind effects	Diffusion flame with no explosion	Yes
Vallejo	Varies with hole size	Yes	No	Circle	Instantly	Point source	Diffusion flame with no explosion	Yes

Table 8 presents a summary of the LNG spill and fire hazard predictions for each of the studies. The distances between the fuel fire and specific thermal hazards are shown in the columns labeled as "Skin Burn Distance" and "Paper Ignition Distance." A secondary indicator of thermal hazard is shown in the "Fire Duration" column.

Significant differences were observed among the studies in the thermal hazard distances calculated, due to each analyst's use of different fuel spill volumes and different approximations in the models for spill spreading, fuel burning, and heat transfer. The *Vallejo*, *Quest,* and *Fay* reports addressed comparable large spills; and the *Lehr* paper concentrated on spills that were twenty-five to fifty times smaller in volume.

Each of the studies differed in its use of models for fire and heat transfer. For example, if identical fuel spill areas and fire thermal emission levels are used as inputs, the heat transfer models used in the *Quest* and *Fay* studies predict thermal hazards that differ by 30%, due to the flame model and pool size assumptions noted in Table 7. Each of the studies assumed a source of ignition (required to start a fire), but excluded consideration of the timing of ignition relative to the release and spreading of the LNG.

Table 8: Summary of Results of Four Recent LNG Studies Analyzed

STUDY	FUEL SPILL VOLUME (m^3)	AREA OF FUEL SPILL (m^2)	"SKIN BURN" DISTANCE[a] (m)	"PAPER IGNITION" DISTANCE[b] (m)	FIRE DURATION (min)
Lehr	500 (hole area not specified)	not reported	500[c]	not reported	2-3
Fay[e]	14,300 ($20m^2$ hole area)	200,000	1900	930	3.3
Quest	12,500 ($20m^2$ hole area)	9503	490[d]	281[d]	28.6
Vallejo	14,300 ($20m^2$ hole area)	120,000	1290	660	9

[a]Thirty-second exposure to heat levels of 5 kW/m^2 causes second-degree skin burns (blisters) at this distance.
[b]Seventeen-second exposure to heat levels of 22 kW/m^2 causes newspaper to ignite at this distance. [SFPE Handbook of Fire Protection Engineering, 2nd ed., National Fire Protection Association, (1995)]
[c] Distance from edge of spill
[d]Assuming a wind speed of 9 m/s (20 mph).
[e] Considers a range of hole sizes. This size chosen for comparison.

The studies also differed in their use of meteorological conditions, such as waves for the locations considered. *Quest* is the only study that used an LNG spill dispersion model in which the impact of waves on the spill pool area was considered. Many of the assumptions and parameters used in the calculations and analyses were not specifically validated.

While existing analytical models and techniques can be used to provide general guidance on the potential hazards associated with a large LNG spill, the four studies do demonstrate how differences in the assumptions of spill size, fire modeling parameters, and environmental factors can have a significant impact on calculated hazard distances. Therefore, the studies show how important it is to use appropriate assumptions, data, and models in trying to develop an accurate assessment of hazards from an LNG spill. While each of the studies provides an example of the potential consequences of a large-scale LNG spill over water, none of the studies identified the probability of the postulated events and assumptions, nor did any discuss mechanisms or strategies that could be implemented to reduce the potential risks of such a spill. Therefore, they do not provide a characterization of how to manage the risks to people and property of a large-scale LNG spill over water

4 ACCIDENTAL LNG BREACH, SPILL, AND HAZARD ANALYSES

Currently, the potential for an accidental LNG cargo tank breach, the dynamics and dispersion of a spill, and the hazards of such a spill, are only generally understood because the combination of LNG ship designs and current safety management practices for LNG transportation have reduced LNG accidents to a level such that there is little historical or empirical information on breaches or spills.

This lack of information forces analysts to make many assumptions and simplifications when calculating the size, dispersion, and thermal hazards of a spill, as discussed in Section 3 and detailed in Appendix A for four recent LNG spill studies. Therefore, it should be understood that while many existing models and techniques can be used to provide adequate guidance on the hazards of an LNG spill, a level of variability can exist in estimating the potentiality and size of a breach and the extent of the hazards from an associated spill.

This section summarizes the modeling and analyses conducted to assess the potential for an accidental breach of an LNG cargo tank, the probable size of a potential accidental breach, and the associated spill size and hazards to people and property from a resulting spill. The detailed results of these analyses are presented in Appendices B – D.

4.1 Analysis of Accidental Breach Scenarios of an LNG Cargo Tank

As noted in Section 2 of this report, the LNG industry has an exemplary safety record, with only eight accidents over the past 40 years. None of these accidents led to a loss of life. Even with this excellent safety record, consideration should be given to what might be a likely LNG cargo tank breach based on a potential accidental collision with another ship, grounding, or ramming. The severity of a breach based on these events depends on the location, vessel design, relative vessel speeds and collision alignment, and mitigation or prevention systems in place to limit potential damage.

Using previously conducted finite element modeling of collisions of a series of ships with a double-hulled oil tanker similar in overall size, mass, and design to an LNG vessel, we were able to estimate the level of damage and hole sizes expected for several different accident scenarios [Ammerman 2002]. These analyses were conducted using PRONTO-3D, a transient dynamic, explicitly integrated, Eulerian finite volume code. The analysis tracked the progressive failure of the struck ship as the striking ship penetrated and the results are discussed and presented in detail in Appendix B. The results show that breaching of the inner hull does not occur until impact velocities exceed approximately 5 – 6 knots for large vessels. For small vessels, such as pleasure craft, the kinetic energy is generally insufficient to penetrate the inner hull of a double-hulled vessel such as an LNG ship. This analysis also calculated that penetration into a double-hulled tanker must be approximately three meters before a hole occurs in the inner hull, which can be used to estimate the minimum size of a penetration to cause a spill in a grounding event.

Because of the additional insulation and third level of containment in many LNG vessels, it is expected that a deeper penetration would be required to rupture the primary LNG cargo tank. Therefore, because of its general design and construction, collision velocities for equivalent hole sizes could be expected to be one to two knots higher for an LNG vessel. This would suggest that the required velocity to cause a breach of an LNG cargo tank during a 90 deg collision with a large vessel could be six to seven knots.

After a collision with an LNG tanker in which LNG is pouring out, the striking ship would probably back out, unless it could not move. In many collisions between two ships, the ships can remain joined for several hours, if significant penetration of one ship occurs. The analysis by Ammerman discussed in Appendix B suggests that as little as 5% – 10% of the generated breach size would be available for the release of LNG. Therefore, the collision of a large ship with an LNG carrier at even 10 knots is expected to produce an effective hole size of no more than approximately one square meter for an LNG spill.

The size and location of potential breaches were used as a basis for analysis of the potential for cryogenic damage to the structural steel of an LNG ship from a spill. Contact of steel with cryogenic fluids is known to cause embrittlement, which can significantly reduce the strength of steel [Vaudolon 2000]. A detailed structural analysis was beyond the scope of this review; but structural integrity embrittlement scoping analyses were conducted to assess the potential damage to an LNG ship from small and large LNG spills based on available fracture mechanics data and models. These analyses were guided by available information on LNG ship and tank designs, construction, and structural steel material property data [Linsner 2004] [Shell 2002] [Wellman 1983] and are discussed in detail in Appendix D.

In general, the results suggest that the critical flaw size for cryogenic damage of common LNG ship steels is less than one-tenth of an inch. It is common to see flaws of this size in typical, welded construction or around corrosion areas. Therefore, it is expected that some cryogenic damage of the LNG vessel, even for some accidental spills, would be likely. The extent and impact of the damage will depend on the breach and spill size and location and effectiveness of risk prevention and mitigation strategies and should be considered relative to overall ship integrity and LNG cargo tank support integrity.

A summary of the potential breach size and potential ship damage from several different accident scenarios is presented in Table 9, based on the detailed analyses presented in Appendices B and D.

Table 9: Estimated LNG Cargo Tank Breach Sizes for Accidental Scenarios

ACCIDENTAL BREACHES			
Type	**Breach Size**	**Tanks Breached**	**Ship Damage**
Accidental collision with small vessel	None	None	Minor[b]
Accidental collision with large vessel	5 - 10m^2 (Spill area 0.5 – 1m^2)[a]	1	Moderate[c]
Accidental Grounding	None	None	Minor

Notes: a - Assumes vessels remain joined during spill event and breach is mostly plugged
b - Minor suggests ship can be moved and unloaded safely
c – Moderate suggests damage that might impact vessel and cargo integrity

The potential breaching of an LNG cargo tank due to an accident, such as a collision or grounding, appears to be minimal. Such a breach can be easily reduced through a number of operational mechanisms, including managing ship traffic, coordinating ship speeds, and by active ship control in inner and outer harbors where the consequences of a potential LNG spill might be most severe. These methods are all currently used by the Coast Guard. Therefore, the safety and hazard issues that can lead to an accidental breach appear manageable with current safety policies and practices.

4.2 Spill and Hazard Analysis of an Accidental Breach of a Cargo Tank

After developing an assessment of the potential sizes of LNG cargo tank breaches, the relative size of various spills and potential hazards and impacts on public safety and property were assessed. These results are discussed in detail in Appendix C for evaluation of spill dispersion and volatilization and thermal impacts; and in Appendix D for evaluation of asphyxiation, LNG ship structural damage, and structural damage to critical infrastructure elements.

4.2.1 Fire Hazard Evaluation of an Accidental LNG Spill

In most of the scenarios identified, the thermal hazards from an accidental spill are expected to manifest as a pool fire, based on the high probability that an ignition source will be available from most of the events identified. Based on a detailed review of the existing experimental literature presented in Appendix C, nominal fire modeling parameters were used to calculate the expected thermal hazards from a fire for the accidental breach scenarios developed.

For example, a solid flame model that accounts for view factors and transmissivity and the Moorhouse correlation for flame height to diameter was used. A low wind condition was assumed; therefore, flame tilt and drag were not required. A surface emissive power of 220 kW/m^2, a transmissivity value of 0.8, and a burn rate of 3×10^{-4} were also used. The volume of the spill assumed for each breached LNG cargo tanks was approximately 12, 500 m^3 or about half the contents of the average LNG cargo tank. The fire duration was based on the hole size, associated spill rate and the assumed burn rate.

Several significant fire parameters have a range of values, thus a parameter variation was performed to ascertain the result on thermal hazard distance. By grouping these parameters to result in extremes of hazard distances, it can be shown that the ranges can vary by factors of five to ten. Such groupings are not probable; therefore, it is more reasonable to choose a nominal case and conservatively vary different factors individually to bounding values to obtain hazard distances. This general approach is presented in Appendix D and a summary of the results calculated using that approach for potential accidental spills is shown in Table 10, where the distance to 37.5 kW/m^2 and 5 kW/m^2 is from the center of the pool.

Table 10: Effect of Parameter Combinations on Pool Diameter in an Accidental Breach

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
1	1	.6	$3X10^{-4}$	220	148	40	177	554
2	1	.6	$3X10^{-4}$	220	209	20	250	784
2	3	.6	$3X10^{-4}$	220	362	20	398	1358

The results presented in Table 10 show that thermal hazards of 37.5 kW/m^2 from a potential accidental breach of an LNG cargo tank and potential fire are expected to exist within approximately 150 - 250 m of the spill, depending on site-specific conditions. Thermal hazards of 5 kW/m^2 are expected to exist out to 500 and 750 m from the spill.

The multi-hole spill scenario presented considers the potential for a failure of three cargo tanks due to a long-duration fire that might occur in a smaller accidental spill. The impact of a fire on adjacent LNG cargo tanks is discussed in detail in Appendix D. Based on this analysis, depending on cargo tank design and fire duration, the potential for cascading damage to additional LNG tanks cannot be ruled out. A conservative estimate of the size of such a cascading fire and the thermal hazard distances from the fire were calculated assuming three simultaneous ruptures. In reality, the tank ruptures would more likely be sequential and, therefore, the hazard distances presented should be considered as conservative estimates.

4.2.2 Evaluation of Vapor Dispersion Hazard of Accidental LNG Spills

In most of the scenarios identified, the thermal hazards from an accidental spill are expected to manifest as a pool fire, based on the high probability that an ignition source will be available from most of the events identified. In some instances, an immediate ignition source might not be available and the spilled LNG could, therefore, disperse as a vapor cloud. Based on Sandia's review of data discussed in Appendix C, the vapor cloud for large spills could extend to beyond 1600 m, depending on spill location and site atmospheric conditions. In congested or highly populated areas, an ignition source would be likely; as opposed to remote areas, in which an ignition source might be less likely.

This suggests that LNG vapor dispersion analysis should be conducted using site-specific atmospheric conditions, location topography, and ship operations to assess adequately the potential areas and levels of hazards to public safety and property. Risk mitigation measures, such as development of procedures to quickly ignite a dispersion cloud and stem the leak, should be considered if conditions exist that the cloud would impact critical areas.

If ignited close to the spill, and early in the spill, the thermal loading from the vapor cloud ignition might not be significantly different from a pool fire, because the ignited vapor cloud would burn back to the source of liquid LNG and transition into a pool fire. If a large vapor cloud formed, the flame could propagate downwind, as well as back to the source. If the cloud is ignited at a significant distance from the spill, the thermal hazard zones can be extended significantly. The thermal radiation from the ignition of a vapor cloud can be very high within the ignited cloud and, therefore, particularly hazardous to people.

In order to obtain LNG dispersion distances to the lower flammability level (LFL) for accidental events, calculations were performed using VULCAN, a CFD code capable of simulating fire and non-fire conditions. The details of this modeling approach are discussed in detail in Appendix D. A low wind speed and highly stable atmospheric condition were chosen because this has shown to result in the greatest distances to LFL from experiment, and thus should be most conservative. A wind speed of 2.33 m/s at 10 m above ground and an F stability class were used for these simulations. The time it took for the LFL to be reached was approximately 20 minutes. As indicated in Table 11, dispersion distances to LFL for LNG spill vapor dispersion from an accidental spill might conservatively be approximately 1500 to 1700 m.

Table 11: Dispersion Distances to LFL for Accidental Spills

HOLE SIZE (m^2)	TANKS BREACHED	POOL DIAMETER (m)	SPILL DURATION (min)	DISTANCE TO LFL (m)
1	1	148	40	1536
2	1	209	20	1710

The results from the fire and vapor dispersion calculations suggest that high thermal hazards for accidental spills do not extend significantly from the spill location, but that some thermal hazards are possible to significant distances, especially if a vapor cloud occurs without early ignition and drifts into a critical area of facility. Table 12 summarizes the estimated results of the impact on public safety and property for an accidental LNG cargo tank breach and spill. In this table, high impact would include a thermal intensity in the range of 37.5 kW/m^2 and low values would correspond to thermal intensities in the range of 5 kW/m^2 .

Table 12: Estimated Impact of Accidental LNG Breaches & Spills on Public Safety & Property

EVENT	POTENTIAL SHIP DAMAGE AND SPILL	POTENTIAL HAZARD	POTENTIAL IMPACT ON PUBLIC SAFETY*		
			~250 m	~250 – 750 m	>750 m
Collisions: Low speed	Minor ship damage, no breach	Minor ship damage	Low	Very Low	Very Low
Collisions: High Speed	LNG cargo tank breach from 0.5 to 1.5 m^2 spill area	▪ Small fire ▪ Damage to ship ▪ Vapor Cloud	High Medium High	Medium Low High - Medium	Low Very Low Medium
Grounding: <3 m high object	Minor ship damage, no breach	Minor ship damage	Low	Very Low	Very Low

*Distance to spill origin, varies according to site

Very low – little or no property damage or injuries
Low – minor property damage and minor injuries
Medium –potential for injuries and property damage
High – major injuries and significant damage to structures

5 INTENTIONAL LNG BREACH, SPILL, AND HAZARD ANALYSES

Currently, the potential for an intentional LNG cargo tank breach, the dynamics and dispersion of a large spill, and the hazards of such a spill, are not fully understood, for two primary reasons. First, the combination of LNG ship designs and current safety management practices for LNG transportation have reduced LNG accidents, so that there is little historical or empirical information on large breaches or spills, as discussed in Section 4. Second, for an intentional event, existing experimental data on LNG spill dynamics, dispersion, and burning over water cover spill volumes that are more than two orders of magnitude less than the spill volumes being postulated in many recent studies.

This lack of information forces analysts to make many assumptions and simplifications when calculating the size, dispersion, and thermal hazards of a spill. This section summarizes the modeling and analyses conducted to assess the potential for an intentional LNG breach and the associated hazards to public safety and property from a resulting spill. The detailed results of these analyses are presented in Appendices B – D.

5.1 Analysis of Intentional Breach Scenarios of an LNG Cargo Tank

As in Section 4, available intelligence and historical data were also used to establish a range of potential intentional LNG cargo tank breaches that could be considered credible and possible. This included evaluation of information on insider and hijacking attacks on ships, and external attacks on ships. Again, the level of knowledge, materials, and planning needed to create intentional breaching events was evaluated. Based on this evaluation, explosive shock physics modeling and analysis were used to perform scoping calculations of potential breach sizes for a range of intentional attacks. Details of these evaluations and analyses are presented in Appendix B.

While a discussion of the specific threats and expected consequences is inappropriate for this report, it is appropriate to discuss the range of breaches that were calculated for a wide range of intentional events. A summary of the modeling and analysis efforts developed and conducted to calculate the potential breaches from various intentional scenarios is presented in an associated Classified report [Hightower 2004].

A computational shock physics code, CTH, and material data were used to calculate expected breach sizes for several different intentional scenarios. CTH is a Eulerian finite volume code and is required to estimate and analyze the large-scale deformations and material responses under very high strain rates that might be developed due to high velocity penetration or explosion scenarios.

Based on the scoping analyses for LNG tanker designs, the range of hole sizes calculated from most intentional breaches of an LNG cargo tank is between 2 – 12 m^2. Our analysis suggests that, in most cases, an intentional breaching scenario would not result in a nominal tank breach of more than 5 – 7 m^2. This range is a more appropriate value to use in calculating potential hazards from spills. Based on the threat it is possible to breach more than one LNG cargo tank during an event.

For both LNG tanker designs, a breach could occur in LNG cargo tanks either above or below the water line. The location impacts the amount of LNG spilled onto the water surface and the amount of LNG that might be spilled into the internal ballast areas between the hulls and vacant hold areas. LNG spilled between the hulls could negatively impact the structural integrity of the tanker or the cargo tanks. Table 13 identifies the level of ship damage from each of the breaching events indicated.

Table 13: Estimated LNG Cargo Tank Breach Sizes for Intentional Scenarios

INTENTIONAL BREACHES		
Breach Size	**Tanks Breached**	**Ship Damage**
0.5 m^2	1	Minor
2 m^2	1	Minor
2 m^2	3	Moderate
12m^2	1	Severe
5 m^2	2	Severe
Premature offloading of LNG	None	Moderate-Severe

Note: *Severe* suggests significant structural damage. Ship might not be able to be moved without significant difficulty and includes potential for cascading damage to other tanks

The intentional breaches and spills shown above include several different events, including a range of potential attacks and insider threats. The large breach sizes calculated, while smaller than commonly assumed in many studies, still provide the potential for large LNG spills. Based on the ranges identified in this study, a nominal breach size of 5 – 7 m^2 was considered. Spill prevention or mitigation techniques should be considered where the consequences or hazards from such breach sizes are most severe.

Table 13 shows that, for many intentional breaching events, the cryogenic damage to the LNG vessel could be minor to moderate, or even severe. Severe structural damage could occur from some of the very large spills caused by intentional breaches. This result is because the volume and rate of the LNG spilled could significantly impact the ship's structural steel. A cascading failure that involves damage to adjacent cryogenic tanks on the ship from the initial damage to one of the LNG cargo tanks is a possibility that cannot be ruled out.

Determination of the potential or likelihood of such an event depends on the breach scenario, the spill location, and any implementation of prevention and mitigation strategies to prevent such an event. In areas where cascading failures might be a significant issue, the use of complex, coupled, thermal, fluid and structural analyses should be considered to improve the analysis of the potential for and extent of structural damage to the LNG ship and other LNG cargo tanks.

5.1.1 Evaluation of the Fire Hazard of an Intentional LNG Spill

In order to determine the general range of hazard levels and to provide a demonstration of how hazard zones can be delineated, the following analysis was performed, the details of which are described in Appendix D.

As stated in Section 4, in most of the scenarios identified, the thermal hazards from an intentional spill are expected to manifest as a pool fire, based on the high probability that an ignition source will be available from most of the events identified. Based on a detailed review of the existing experimental literature presented in Appendix C, nominal fire modeling parameters were used to calculate the expected thermal hazards from a fire for the intentional breach scenarios developed. The same modeling approach and assumptions as discussed in Section 4 were used for these analyses. While the details of the analyses are presented in Appendix D, a summary of these results is shown in Table 14, where the distances to 37.5 kW/m^2 and 5 kW/m^2 are from the center of the pool.

Table 14: Intentional Breach — Effect of Parameter Combinations on Pool Diameter

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
2	3	.6	3×10^{-4}	220	209	20	250	784
5	3	.6	3×10^{-4}	220	572	8.1	630	2118
5*	1	.6	3×10^{-4}	220	330	8.1	391	1305
5	1	.9	3×10^{-4}	220	405	5.4	478	1579
5	1	.6	2×10^{-4}	220	395	8.1	454	1538
5	1	.6	3×10^{-4}	350	330	8.1	529	1652
12	1	.6	3×10^{-4}	220	512	3.4	602	1920

*nominal case

The results presented in Table 14 show that the thermal hazards of 37.5 kW/m^2 are expected to occur within approximately 500 m of the spill for most of the scenarios evaluated. For the 2 m^2 three-hole breach, it was assumed that individual pools would form; whereas, for the 5 m^2 three-hole breach, a single pool was assumed to form. The release from the three holes was considered to happen simultaneously. It should be noted that these conditions consider cascading damage resulting from fire or cryogenic-induced failure.

Most of the studies reviewed assume that a single, coherent pool fire can be maintained for very large pool diameters. This would be unlikely due to the inability of air to reach the interior of a fire and maintain combustion on an LNG pool that size. Instead, the flame pool envelope would break up into multiple pool fires (herein: ‘flamelets’), the heights of which are much less than the fuel bed diameter used in the calculations by the four previously discussed studies. This breakup into flamelets results in a much shorter flame height than that assumed for a large pool diameter. In reality, L/D (height/pool diameter) would probably be much smaller than that assumed by the correlations in many studies, which predict an L/D ratio between 1.0 and 2.0. A more realistic ratio could be less than 1.0 [Zukoski 1986] [Corlett 1974] [Cox 1985].

Because the heat radiated by the flamelets would be far less than the heat radiation calculated in the many studies (based on a large pool fire), the amount of radiative heat flux that an adjacent object receives would be less, thereby decreasing the size of the thermal hazard zone. As discussed in Appendix D, the use of a mass fire assumption could reduce hazard distances for large spills. The development of fire whirls might increase the hazard zone. Therefore, this type of pool fire model should be carefully considered to improve thermal hazards analysis from potential large spills.

The results presented suggest that the potential thermal hazards for large spills can vary significantly, based on the uncertainty associated with potential spill sizes, dispersion variations, and threats. Based on the estimated pool size for large spills, even with the possibility of reduction in effects for mass fires as opposed to single pool fires, high thermal hazards approaching 37.5 kW/m^2 could probably extend to approximately 500 meters. The thermal hazards between 500 meters and 1600 meters decrease significantly. The hazards would be low, approximately 5 kW/m^2 beyond 1600 m from even a large spill. Based on these observations, approximate hazard zones seem to exist between 0 – 500 m, 500 – 1600 m, and over 1600 m, and were used to develop guidance on managing risks for LNG spills.

5.1.2 Evaluation of Vapor Dispersion Hazard of Intentional LNG Spills

In most of the scenarios identified, the thermal hazards from a spill are expected to manifest as a pool fire, based on the high probability that an ignition source will be available from most of the events identified. In some instances, such as an intentional spill without a tank breach, an immediate ignition source might not be available and the spilled LNG could, therefore, disperse as a vapor cloud. For large spills, the vapor cloud could extend to more than 1600 m, depending on spill location and site atmospheric conditions. In congested or highly populated areas, an ignition source would be likely, as opposed to remote areas, in which an ignition source might be less likely.

As mentioned in Section 4, the impact from a vapor cloud dispersion and ignition from a large spill can extend beyond 1600 meters, based on our review of external data discussed in Appendix C. This suggests that LNG vapor dispersion analysis should be conducted using site-specific atmospheric conditions, location topography, and ship operations to assess adequately the potential areas and levels of hazards to public safety and property. Consideration of risk mitigation measures, such as development of procedures to quickly ignite a dispersion cloud and stem the leak, if conditions exist that the cloud would impact critical areas.

If ignited close to the spill, and early in the spill, the thermal loading from the vapor cloud ignition might not be significantly different from a pool fire, because the ignited vapor cloud would burn back to the source of liquid LNG and transition into a pool fire. If a large vapor cloud formed, the flame could propagate downwind, as well as back to the source. If the cloud is ignited at a significant distance from the spill, the thermal hazard zones can be extended significantly. The thermal radiation from the ignition of a vapor cloud can be very high within the ignited cloud and, therefore, particularly hazardous to people.

In order to obtain LNG dispersion distances to LFL for intentional events, calculations were performed using VULCAN, as discussed in Section 4. A low wind speed and highly stable atmospheric condition were chosen because this state has shown to result in the greatest distances to LFL from experiment, and thus should be the most conservative. A wind speed of 2.33 m/s at 10 m above ground and an F stability class were used for these simulations. For intentional events, two cases were run, one for the nominal case of a 5-m^2 hole and one tank breach, and the other for a 5-m^2 hole and three tanks breached. This case is the largest spill; hence, it should give the greatest LFL for intentional events. As indicated in Table 15, the dispersion distance to LFL for intentional events might extend from nominally 2500 m to a conservative maximum distance of 3500 m for this unlikely event.

While previous studies have addressed the vapor dispersion issue from a consequence standpoint only, the risk analysis performed as part of this study indicates that the potential for a large vapor dispersion from an intentional breach is highly unlikely. This is due to the high probability that an ignition source will be available for many of the initiating events identified, and because certain risk reduction techniques can be applied to prevent or mitigate the initiating events identified. The significant distances, though, of a potential vapor dispersion suggest that LNG vapor dispersion analysis and risk mitigation measures should be carefully considered to protect adequately both the public and property.

Table 15: Dispersion Distances to LFL for Intentional Spills

HOLE SIZE (m^2)	TANKS BREACHED	POOL DIAMETER (m)	SPILL DURATION (min)	DISTANCE TO LFL (m)
5	1	330	8.1	2450
5	3	572	8.1	3614

The analyses from the fire and vapor dispersion calculations suggest that high thermal hazards from intentional events extend significantly from the spill location. Table 16 summarizes the general impacts on both public safety and property for intentional breaches and spills. In this table, high impact would include a thermal intensity in the range of 37.5 kW/m^2 and low values would correspond to thermal intensities in the range of 5 kW/m^2 .

These results should be used as guidance, bearing in mind that these distances will vary, based on site-specific factors and environmental conditions.

Table 16: Estimated Impact of Intentional LNG Breaches & Spills on Public Safety & Property

<table>
<tr><th rowspan="2">EVENT</th><th rowspan="2">POTENTIAL SHIP DAMAGE AND SPILL</th><th rowspan="2">POTENTIAL HAZARD</th><th colspan="3">POTENTIAL IMPACT ON PUBLIC SAFETY[a]</th></tr>
<tr><th>~500 m</th><th>~500 – 1600 m</th><th>>1600 m</th></tr>
<tr><td rowspan="6">Insider Threat or Hijacking</td><td rowspan="3">Intentional, 2-7 m^2 breach and medium to large spill</td><td>▪ Large fire</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Damage to ship</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Fireball</td><td>Medium</td><td>Low</td><td>Very Low</td></tr>
<tr><td rowspan="3">Intentional, large release of LNG</td><td>▪ Large fire</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Damage to ship</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Vapor cloud fire</td><td>High</td><td>High - Med</td><td>Medium</td></tr>
<tr><td rowspan="3">Attack on Ship</td><td rowspan="3">Intentional, 2-12m^2 breach and medium to large spill</td><td>▪ Large fire</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Damage to ship</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>▪ Fireball</td><td>Medium</td><td>Low</td><td>Very Low</td></tr>
</table>

[a] Distance to spill origin, varies according to site

Very low – little or no property damage or injuries
Low – minor property damage and minor injuries
Medium –potential for injuries and property damage
High – major injuries and significant damage to structures

6 RISK REDUCTION STRATEGIES

A customized, risk management approach is necessary because every LNG site has unique features. Performance-based safety requirements are often used in instances where there is a lack of good information on operational consequences or hazards. In many cases, safety information does exist and, based on available data, prescriptive safety requirements described by codes, standards, or other regulations are often developed and recommended. For combined safety and security applications, where threats can change or grow rapidly, performance-based regulations and strategies can often provide the flexibility needed to respond to the evolving security and safety needs.

To obtain the most complete picture of the potential consequences in a given breach scenario, a target-mechanism-consequence model is suggested. The target is the vulnerable element on which some mechanism acts to produce an undesired consequence. For example, a private residence (target) on a nearby shore can be ignited by radiant energy from a burning LNG spill (mechanism) that might lead to loss of property (consequence). Following the example, an LNG spill might trace to a number of causes, such as structural insult or premature off-loading of LNG. This section identifies some targets, mechanisms, and consequences that might be useful in developing approaches to manage risks at existing or future LNG terminal sites.

6.1 Target – Mechanism – Consequence Model

<u>Target</u>

Targets are usually identified as physical objects or subsystems, but people (operators, residents, etc.) are targets as well.

Table 17: Targets Table

TARGETS AFLOAT	FIXED TARGETS IN WATER	TARGETS ASHORE
LNG tanker	Bridge	LNG storage terminal
Other tanker (e.g., gasoline)	Tunnel	Adjacent industry
Security escort	LNG terminal or other pier	Residential & business districts
Rescue vessel	Ship channel	Roadways
Pleasure boat	Oil rig	Airport

Mechanism

Failure mechanisms can be either accidental or intentional; and they can be categorized under physical, cyber and communications, and interpersonal.

Table 18: Mechanisms Table

PHYSICAL	CYBER AND COMMUNICATIONS	INTERPERSONAL
Collisions & other impacts	On-ship communications	Sabotage
Brittle fracture (cryogenic)	On-ship control	Espionage
Bulk explosions	Harbor master communications	Infiltration
Directed explosions (shaped charge)	Process control and data acquisition systems	Subversion
Fire dynamics	Ship to ship and ship to shore communications	Diversion
Cryogenic liquid dynamics	Tactical and emergency communication systems	Hiding

Consequence

Intentional mechanisms (deliberate acts) can often produce greater consequences than accidental mechanisms because the perpetrator can maximize the effects of an attack by choosing the time and place. In fact, the perpetrator might coordinate several, simultaneous attacks, thus compounding the consequences. Consequences can include local, cascading, and delayed effects. All these effects must be considered in developing an overall risk reduction and risk management approach.

Table 19: Consequences Table

LOCAL	CASCADING	DELAYED
Death or injury to tanker crew	Death or injury to escort vessel crews	Death or injury to rescue vessel crews
Damage or loss of LNG vessel	Damage or loss of escort vessels	Disruption of future LNG deliveries
Blockage of waterway	Hold on operations at other waterways	Denial of future operations at other waterways
Fire damage to nearby structures or infrastructures	Loss of use of other infra-structures	Denial of future operations at receiving terminal
Public deaths and/or injuries	Public deaths and/or injuries	Loss of use of infrastructures or properties
	Economic losses	Economic losses and loss of energy supplies

6.2 Risk Management Strategies: Prevention and Mitigation

Many factors can impact risks to public safety and property from an LNG spill: design, materials selection, manufacturing methods, inspection and testing, assembly techniques, worker training, and safety operations, among others. For example, two ship design features that can impact risk are hull type (single vs. double) and hull material (steel vs. a more exotic material). Other significant factors include terminal location and design, port handling elements (e.g., tugboats and firefighting equipment), communications systems, and emergency response capabilities.

It is important to realize that a decision involving large capital expense can have long-lasting effects (e.g., LNG terminal site selection). For this reason, it is imperative to consider carefully all risk management decisions in order that residual or future risks can be managed to an acceptable level.

In general, risk can be managed by prevention or mitigation. Prevention seeks to avoid an accident or attack; mitigation reduces the effects of an accident or attack. Table 20 provides some general strategies for prevention and mitigation. Combinations of these types of strategies can improve both safety and security involving either accidental or intentional incidents.

While the prevention and mitigation strategies identified in the table are possible, many might not be cost-effective or even practical in certain locations or applications. Risk management should be based on developing or combining approaches that can be effectively and efficiently implemented to reduce hazards to acceptable levels in a cost-effective manner.

This type of approach has been in use and is in use by the LNG industry, the Coast Guard, and public safety organizations to ensure the safety of the transportation of LNG. These efforts include a number of design, construction, safety equipment, and operational efforts to reduce the potential for an LNG spill. Existing safety and security efforts for LNG vessels are noted following Table 20 [Scott 2004].

Regardless, all LNG vessels that enter the U.S. must meet both domestic regulations and international requirements. Domestic regulations for LNG vessels were developed in the 1970’s under the authority of the various vessel inspection statutes now codified under Title 46 of the United States Code, which specifies requirements for a vessel's design, construction, equipment, and operation. These regulations closely parallel international LNG requirements; but are more stringent in the following areas: the requirements for enhanced grades of steel for crack-arresting purposes in certain areas of the hull, specification of higher allowable stress factors for certain independent type tanks, and prohibition of cargo venting as a means of regulating cargo temperature or pressure.

Table 20: Prevention and Mitigation Strategies

PREVENTION	MITIGATION
ISOLATION ▪ physical separation (distance) ▪ physical barriers ▪ keep-out or exclusion zones (buffers) ▪ interrupted operations (aircraft, bridge traffic)	RECOVERY OPERATIONS ▪ plans in place & current ▪ equipment & people in place & ready ▪ drills ▪ evacuation plans
VOID SPACES WITH INERT GAS	MAINTAIN MOBILITY (tanker + towing)
INERTING OF VOID SPACES	LIMIT SPILL AMOUNTS & RATES
VARIED TIMES OF OPERATIONS	SECURITY EMERGENCY RESPONSE FORCES
INTELLIGENCE ▪ communication links in place & ready ▪ timely updates ▪ interagency communication links	FIRE-FIGHTING CAPABILITIES ▪ leak detectors ▪ deluge systems ▪ radiant barriers (high-pressure high-density foam systems) ▪ backup fire fighting capabilities
INCREASED MOBILITY (tugs)	REDUNDANT MOORING & OFFLOADING CAPABILITIES
ARMED SECURITY ESCORT (boat, aircraft or on-board)	OFFSHORE MOORING & OFFLOADING CAPABILITIES
SWEEPS (divers, sonar, U.S.CG boarding)	SPEED LIMITS
SURVEILLANCE (on-ship, on-land, underwater & aerial)	CRYOGENICALLY-HARDENED VESSEL
EMPLOYEE BACKGROUND CHECKS	SHIP ARMOR, ENERGY-ABSORBING BLANKETS
TANKER ACCESS CONTROL PROGRAM	MISSILE DEFENSE SYSTEM
STORM PREDICTION & AVOIDANCE PLANS	REDUNDANT CONTROL SYSTEMS
SAFETY INTERLOCKS	BACKUP FUEL SOURCE (oil)

All LNG vessels in international service must comply with the major maritime treaties agreed to by the International Maritime Organization (IMO), such as the International Convention for the Safety of Life at Sea, popularly known as the "SOLAS Convention," and the International Convention for the Prevention of Pollution from Ships, known as the "MARPOL Convention." In addition, LNG vessels must comply with the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk, known as the "IGC Code."

Before being allowed to trade in the United States, operators of LNG carriers must submit detailed vessel plans and other information to the Coast Guard's Marine Safety Center (MSC) to establish that the vessel has been constructed to the higher standards required by U.S. regulations. Upon satisfactory plan review and on-site verification by Coast Guard marine inspectors, the vessel is issued a Certificate of Compliance. The Certificate of Compliance is valid for a two-year period, subject to an annual examination by Coast Guard marine inspectors, who verify that the vessel remains in compliance with all applicable requirements.

Because of the safety and security challenges posed by transporting millions of gallons of LNG, vessels typically undergo a more frequent and rigorous examination process than conventional crude oil or product tankers. LNG vessels are boarded by marine safety personnel prior to U.S. port entry to verify the proper operation of key navigation, safety, fire fighting, and cargo control systems.

LNG vessels are subject to additional security measures. Many of the security precautions for LNG vessels are derived from analysis of "conventional" navigation safety risks, such as groundings, collisions, propulsion, and steering system failures. These precautions pre-date the events of September 11, 2001, and include such items as traffic control measures for special vessels that are implemented when an LNG vessel is transiting or approaching a port and security zones around the vessel to prevent other vessels from approaching it. Also included are escorts by Coast Guard patrol craft and, as local conditions warrant, coordination with other Federal, State and local transportation, law enforcement and/or emergency management agencies to reduce the risks to, or reduce the interference from, other port area infrastructures or activities. All such measures are conducted under the authority of existing port safety and security statutes, such as the Magnuson Act (50 U.S.C. 191 et. seq.) and the Ports and Waterways Safety Act.

Since September 11, 2001, additional security measures have been implemented, including the requirement that all vessels calling in the U.S. must provide the Coast Guard with a 96-hour advance notice of arrival (increased from 24 hours advance notice, pre-9/11). This notice includes information on the vessel's last ports of call, crew identities, and cargo information. Based on vessel-specific information, the Coast Guard conducts at-sea boardings, in which Coast Guard personnel conduct special "security sweeps" of the vessel and ensure that "positive control" of the vessel is maintained throughout its port transit. This is in addition to the safety-oriented boardings previously described.

One of the most important post-9/11 maritime security developments has been the passage of the Maritime Transportation Security Act of 2002 (MTSA). Under the authority of MTSA, the Coast Guard has developed new security measures applicable to vessels, marine facilities, and maritime personnel. The domestic maritime security regime is closely aligned with the International Ship and Port Facility Security (ISPS) Code. Under the ISPS Code, vessels in international service, including LNG vessels, must have an International Ship Security Certificate (ISSC). To be issued an ISSC, the vessel must develop and implement a threat-scalable security plan that establishes access control measures, security measures for cargo handling and delivery of ships stores, surveillance and monitoring, security communications, security incident procedures, and training and drill requirements. The plan must also identify a Ship Security Officer who is responsible for ensuring compliance with the ship's security plan.

For an LNG terminal, regulations developed under the authority of the Ports and Waterways Safety Act assign to the Coast Guard the responsibility for safety issues within the "marine transfer area" of LNG terminals. The "marine transfer area" is defined as that part of a waterfront facility between the vessel, or where the vessel moors, and the first shutoff valve on the pipeline immediately before the receiving tanks. Safety issues within the marine transfer area include electrical power systems, lighting, communications, transfer hoses and piping systems, gas detection systems and alarms, firefighting equipment, and operations such as approval of the terminal's Operations and Emergency Manuals and personnel training.

New maritime security regulations have been recently developed for terminal facilities. These regulations require the LNG terminal operator to conduct a facility security assessment and develop a threat-scalable security plan that addresses the risks identified in the assessment. Much like the requirements prescribed for vessels, the facility security plan establishes access control measures, security measures for cargo handling and delivery of supplies, surveillance and monitoring, security communications, security incident procedures, and training and drill requirements.

6.3 Risk Reduction Examples

Table 21 below presents selected scenarios that provide examples of potential events and several prevention and mitigation approaches that could be used to reduce risks to public safety and property. Following the table, examples are given for each category of how these prevention and mitigation strategies can be implemented individually or in combination to reduce risks and consequences for a given location.

Many of the strategies identified are already under consideration or being implemented by the Coast Guard. Other strategies identified might be considered in conjunction with existing strategies at many sites. While risks can seldom be reduced to zero, prevention of the higher consequence events can significantly reduce hazards to public safety and property and facilitate mitigation of the remaining lower consequence and lower risk events.

As discussed in Section 3, prevention and mitigation strategy implementation should key on effectiveness, costs, and operational impacts. The level of risk reduction required should be determined in conjunction with local public officials and public safety organizations such as police and fire departments, emergency response services, port authorities, the Coast Guard, and other appropriate stakeholders.

Risk reduction strategies that are effective at one site might not be effective at another site. Therefore, the examples provided in Table 21 below should be considered in the context of how a risk management approach might be customized to yield benefits to public safety and property while having limited operational impacts.

Table 21: Examples of Risk Prevention and Mitigation Strategies for Potential Threats

SCENARIO	TARGETS	MECHANISM	POTENTIAL CONSEQUENCES		RISK REDUCTION MEASURES	
			LOCAL	CASCADING	PREVENTION	MITIGATION
Ramming	Fixed targets afloat or ashore	Mechanical distortion	Fire & ship damage	Large-scale fire	▪ Control of ship ▪ Increased mobility ▪ Tug escort	▪ Absorbing barriers on fixed targets ▪ Fire-fighting capability
Triggered Explosion	Fixed targets afloat	Pre-placed, coordinated explosion	Ship damage	Large-scale fire, blockage of waterway	▪ Early interdiction and surveillance ▪ Sweeping ▪ Intelligence ▪ Control of ship	▪ Emergency response force ▪ Evacuation plans ▪ Towing option
Insider Takeover or Hijacking	Fixed targets afloat or ashore	Standoff & negotiation, or explosion	Elevated public concern or fire & ship damage	Public demands to cease operations or large-scale fire	▪ Early interdiction & searches ▪ Control of ship ▪ Employee background checks	▪ Emergency response force ▪ Evacuation plans
Terrorist	Target afloat	Vessel carrying explosives	Fire & ship damage	Large-scale fire and blockage of waterway	▪ Security zones ▪ Safety halo around ship ▪ Intelligence	▪ Emergency response force ▪ Evacuation plans ▪ Towing option

Ramming

Ramming could occur between an LNG tanker and a fixed object or between a boat and an LNG tanker. As noted in Appendix B, unless the LNG tanker speed is above 5 – 7 knots or the object is very sharp, ramming of the LNG tanker into an object will not likely penetrate both hulls and the LNG cargo tank. Likewise, if the LNG tanker is rammed by a small boat, such as a pleasure craft, the kinetic energy is insufficient to penetrate the inner hull of a double-hulled LNG ship.

Therefore, while ramming does not appear to be a major concern or present significant hazards, changes in some safety and security operations could reduce the chances of a ramming event. For example, requiring tug escorts for LNG ships in high consequence areas would reduce the potential for an insider to ram intentionally an LNG vessel into a critical infrastructure element. Another option would be to ensure that crewmembers have been properly evaluated and the ship interdicted and searched sufficiently in advance of entry into the U.S. to thwart a hijacking attempt or insider sabotage. These efforts reduce the ability of an adversary to pick the time, place, and target for a ramming event and reduce the risk from a potential ramming scenario.

Triggered Explosion

Triggered explosion events assume pre-placed explosives, either on the ship or in a fixed location. At some sites, sweeping of the waterway, harbor bottom, and terminal areas for explosives or mines might be required. This is especially true for high hazard areas, shallow waterways, or terminals where explosives might be hidden. To prevent sabotage of an LNG cargo tank through a triggered explosive on board a ship, the same type of early interdiction, searches, and control of the ship discussed in the ramming prevention scenario could be applicable.

Insider Takeover or Hijacking

A number of security measures, including armed security control aboard the ship and early interdiction and inspection of the ship prior to its entry into the U.S., could prevent many of the large breaching scenarios identified in Sections 4 and 5. This could significantly reduce hazards levels and enable spill mitigation measures available to emergency response organizations to be used effectively.

A ship hijacking should be considered credible through coordinated efforts by insiders or others. The threat could proceed with the breach and spill of an LNG cargo tank through use of planted or smuggled explosives or by overriding offloading system safety interlocks to discharge LNG intentionally onto the ship, onto unloading terminal equipment, or onto the water. While a number of operational procedures have been implemented to help prevent this type of potential scenario, control and surveillance of an LNG ship must be appropriately maintained to ensure adequate time to respond to a potential hijacking event.

External Terrorist Actions

External terrorist attacks could come from a number of avenues, including attack of the LNG ship with a wide range of munitions or bulk explosives. A U.S.S Cole-type attack is often suggested as a potential attack scenario, as well as attacks with munitions such as rocket-propelled grenades, or missiles or attacks by planes. Depending on the size of the weapon or explosive charge and the location of the attack, the potential breach and LNG spill will vary.

Common approaches to prevent or mitigate these events are to make structures more resistant to attacks or to increase the standoff distance between the initiation of explosives and the ship. While security zones are presently used effectively for safety considerations at most of the LNG import locations in the U.S., a security halo for an LNG ship would have to be much smaller and effectively maintained to develop the security zones needed to prevent some of these events. Such measures could prevent a potential attacker from approaching close enough to cause severe damage to an LNG vessel. This security zone might require different escort ships and escort procedures, improved overhead and subsurface surveillance, enhanced training, or enhanced security response procedures.

6.4 Recommended Focus for Risk Prevention

The threats considered and the safety and security measures employed to address them must be based on site-specific and location-specific conditions. The level of risk prevention or mitigation required will depend on the site and its location relative to major population areas and critical infrastructures. In all cases, the risk reduction strategies identified should be considered from a cost-effectiveness viewpoint; i.e. reducing risks to acceptable levels in the most cost-effective manner possible for a given site and location.

To guide risk management efforts and reduce impact on operations, Sandia recommends defining threat-scalable safety and security measures, and then tying safety and security related operations to these levels, which is the approach taken by the Department of Homeland Security for its threat advisory system. In this way, for each threat condition, protection and operations changes can be implemented in order to maintain the level of risk to public health and safety at acceptable levels.

Although the Department of Homeland Security defines threat levels, this might or might not be appropriate for an LNG transport system. As a minimum, Sandia suggests three levels — normal, off normal, and emergency. Unlike Homeland, whose sole focus is security, LNG would extend this formalism both to security and to safety.

Generally, the safety efforts currently in place for LNG transportation over water have been very effective in preventing accidents and appear to be adequate. At some locations, however, security efforts required to prevent intentional breaching events might have to be increased in order to reduce the risks to public health and safety. Since 9/11, current safety and security efforts have been increased and are continuing to evolve to meet the challenges of ever changing security threats.

As shown in Tables 20 and 21, multiple security strategies are available to help prevent or mitigate these events and often are complementary with existing LNG safety strategies already in practice. Suggested general security improvements to address the three major intentional breach scenarios should account for site-specific conditions and hazards and include (as required):

- Appropriate off-shore LNG ship interdiction and inspections for explosives, hazardous materials, and proper operation of safety systems;
- Appropriate monitoring and control of LNG ships when entering U.S. waters and protection of harbor pilots and crews;
- Enhanced safety zones around LNG vessels (safety halo) that can be enforced;
- Appropriate control of airspace over LNG ships; and
- Appropriate inspection and protection of terminal areas, tug operations prior to delivery and unloading operations.

Effective implementation of these types of security measures, along with complementary measures such as improved intelligence and cooperation, could reduce the potential for several types of intentional events. (The types of measures needed to reduce specific threats are discussed in more detail in an associated classified report [Hightower 2004].
A reduction in threats would reduce the potential sizes of breaches, and associated spills and hazards. This could significantly reduce the risks to people and property from an LNG spill over water.

Before implementation of specific safety or security measures is contemplated at a site, a baseline risk analysis should be conducted, a minimum acceptable risk estimated, and vulnerabilities and hazards evaluated. After the initial risk analysis has been completed, prevention and mitigation measures or strategies can then be considered and evaluated. These can then be compared to assess if they provide the enhancements required to reduce the risks of an LNG spill to acceptable levels for a site.

6.5 Application of the Risk Management Process

So far, in this section we have discussed risk reduction for areas or activities within the larger system that includes the LNG tanker, the waterways it travels, and neighboring infrastructures. We used the risk management guidance and safety information developed in this report to assess ways to enhance operations and reduce the potential risks to the public. Hopefully, this will provide the reader with suggestions on how to consider various issues, including terminal location and site conditions, operational conditions, environmental effects, and safety and security concerns and measures. To be feasible, such a process must be effective from a surety standpoint, affordable, possible to implement in a timely fashion, minimize environmental impact, and be otherwise amenable to regulators and stakeholders.

We are not intending to suggest a "cookbook" methodology for selecting new sites; however, we want the reader to understand what type of issues should be considered and what various measures should be applied to try to achieve appropriate levels of protection of public safety and property for LNG imports.

Applying the Risk Management Process to LNG Imports

Risk management of an LNG import facility should be viewed as a system that includes the LNG tanker, the import terminal facilities and location, the navigational path, and the nearest neighbors along the navigational path and at the import terminal. Four classes of attributes affect the overall risks. These include:

- The context of the import facility – location, site specific conditions, LNG import, importance to the region;
- Potential targets and threats – potential accidental events, credible intentional events, and ship or infrastructure targets;
- Risk management goals– identification of levels of consequences to be avoided, such as injuries and property damage, LNG supply reliability required; and
- Protection system capabilities – LNG tanker safety and security measures, LNG import operations safety and security measures, and early warning and emergency response/recovery measures.

In the risk management process shown in Figure 3, the four attributes discussed are then evaluated to determine if the protection system in place can effectively meet the risk management goals identified for a specific import terminal site and operations. If so, then the safety and security measures and operations developed for the LNG import operations are adequate. Import operations should be reviewed on a regular basis to assess whether changes in context, targets or threats, risk management goals or risk management systems have changed such that a reassessment of risks is needed.

If the initial risk assessment determines that the identified risk management goals are not being met, then potential modifications in location and site conditions, import operations, safety and security measures, emergency response and early warning measures should be assessed to determine effective improvements in the overall risk management system Below, we provide a summary of the elements that should be considered for LNG import facility applications for each step of the risk management process identified in Figure 3 of this report. These steps provide a context of how the safety analysis and risk guidance provided in this report can be used to evaluate options to protect property and public health and safety associated with LNG import terminals and operations.

<u>Step One</u> - Characterize Assets

In this step, the context of the LNG facility such as location, site-specific conditions, and nominal operations should be identified and developed. Information that should be collected and considered includes:

- **Type and Proximity of Neighbors (Sections 3.3, 4.2, and 5.1)**
  - Distance to residential, commercial, and industrial facilities or other critical infrastructures such as bridges or tunnels, and
  - Transit – Near or in major ship channel or remote from channel
- **Environmental Conditions (Sections 3.2 and 3.3)**
  - Wind-driven Spill Movement & Dispersion – prevailing wind direction, speed, and variability,
  - Severe Weather Considerations – hurricanes, storm surges,
  - Tidal-driven Spill Movement & Dispersion – height, current, and influence on spill movement and dispersion,
  - Seismic issues - ground displacement, soil liquefaction, and
  - Temperature issues – ice, thermal impediment to operations
- **Nominal Operational Conditions (Sections 2.1, 2.2, and 3.3)**
  - LNG tanker size and design,
  - Expected frequency of shipments,
  - Importance of LNG Shipments – Available storage, seasonal demands, percentage of regional or local supply, and
  - Transit – additional traffic (near other large ships, pleasure boats) and distance to it; transit near critical infrastructures, such as other terminals, commercial areas, or residential areas; number of critical facilities along transit; distance to critical facilities along transit.

<u>Step Two</u> – Identify Potential Threats (Sections 4.1 and 5.1)

In this step, the potential or likely threats expected for the facility, based on site location and relative attractiveness of either an LNG tanker or other nearby targets, should be identified.

- **Accidental Event Considerations –** shipping patterns, frequency of other large ships, major objects or abutments to be avoided, warning systems, weather impacts on waterways or operations,
- **Intentional Event Considerations –** threat levels identified by Homeland Security, identified threats, past threats and shipping attacks, difficulty of attack scenarios for a given site, and

- **Attractiveness of Targets –** impact of LNG tanker attack, impact on facilities near navigational route, impact on other facilities near site not associated with LNG operations.

<u>Step Three</u> - Determine Risk Management Goals and Consequence Levels (Section 6.1)

Identify risk management goals or consequence levels for LNG operations, including potential property damage and public safety (including injury limits). Setting of the goals and levels would be conducted in cooperation with stakeholders, public officials, and public safety officials. Consideration should be given to evaluating a range of potential risk management goals and consequence levels. In this way, an assessment of the range of potential costs, complexity, and needs for different risk management options can be compared and contrasted. Common risk management goals and consequence level considerations should include:

- Allowable duration of a loss of service, ease of recovery,
- Economic impact of a loss of service,
- Damage to property and capital losses from a spill and loss of service, and
- Impact on public safety from a spill – potential injuries, deaths.

<u>Step Four</u> - Define Safeguards and Risk Management System Elements (Section 6.2)

This step includes identifying all of the potential safety and security elements and operations available on the LNG tanker, at the terminal, or in transit. They include not only safety features but also safety and security-related operations and emergency response and recovery capabilities. These include:

- **Operational Prevention and Mitigation Considerations**
  - LNG tanker safety/security features,
  - Proximity and availability of emergency support – escorts, emergency response, fire, medical and law enforcement capabilities,
  - Early warning systems,
  - Ship interdiction and inspection operations and security forces, and
  - Ability to interrupt operations in adverse conditions – weather, wind, waves.
- **Protective Design**
  - Design for storm surges, blasts, thermal loading,
  - Security measures – fences, surveillance, exclusion areas,
  - Effective standoff from residential, commercial, or other critical infrastructures based on recommended hazard distances from an LNG spill over water, and
  - Redundant offloading capabilities.

Step Five - Analyze System and Assess Risks (Sections 3.3, 4.2, and 5.1)

In this step, the defined risk management goals and consequence levels should be compared to the existing system safeguards and protective measures. This effort would include evaluation of each element of the event tree identified in Figure 4 for a potential spill that might occur for the site-specific conditions, threats, and calculated hazard distances and hazard levels.

If the system safeguards in place provide protection of public safety and property that meet risk management goals, then the overall risks of an LNG spill would be considered compatible with public safety and property goals. The risk management process should be updated regularly to assess whether changes in threats or threat levels, operations, LNG tanker design, or protective measures have occurred that would impact the ability of the system safeguards to meet identified or improved public health and safety goals.

Step Six – Assess Risk Prevention and Mitigation Techniques (Sections 6.2 and 6.3)

If the potential hazard distances and hazard levels calculated exceed the consequence levels and risk management goals for the LNG terminal and import operations, then the enhanced risk mitigation and prevention strategies identified in Table 20 should be considered. While many of the options listed would be possible for a given site, developing approaches or combinations of approaches should be considered that can be effectively and efficiently implemented and that provide the level of protection, safety, and security identified for the LNG operations at each site.

7 GUIDANCE: SAFETY AND RISK ANALYSIS AND RECOMMENDATIONS

As discussed throughout this report, several major issues are associated with the potential for a large LNG spill over water. They include the potential for an accidental or intentional act that could cause an LNG spill, evaluation of the dynamics of the potential spill and LNG dispersion, the potential consequences that might occur from the range of spills, and strategies or efforts that might be employed to either prevent or mitigate the risks of a spill. Because costs to prevent and mitigate the potential consequences of an extreme event such as an LNG spill can be extensive, performance-based risk management approaches can be used to ensure that public safety and property are effectively protected.

In this study, a risk management approach is suggested for reducing the risks of LNG spills over water. Such an approach provides a systematic method for considering the potential of a breach event, assessing the expected LNG dispersion and potential consequences, and identifying prevention and mitigation strategies to reduce risks for site-specific conditions. Using available ship and experimental data, Sandia was able to evaluate both accidental and intentional breach scenarios of an LNG cargo tank. These efforts included assessments of past LNG spill and dispersion testing and modeling, estimates of hazards from an LNG spill, and identification of approaches to prevent or mitigate large LNG spills over water.

Modeling and assessing the impacts of potentially large LNG spills over water is a challenge that would benefit from additional, large-scale experiments to validate analysis techniques and approaches. These efforts would help reduce the uncertainty and improve the accuracy in assessing the impact and associated consequences of large LNG spills over water. Additional testing might best be conducted as part of a joint public/private effort with industry and government agencies to ensure widespread acceptance and support.

7.1 Guidance: Using Models for Spill and Hazard Evaluations

A detailed review of LNG dispersion and fire modeling methods and approaches suggests that current computational models require many assumptions. Table 22 shows the impact different parameters have on a consequences or hazards analysis. The table should be used as guidance on the level of detail needed in evaluating hazards from an LNG spill. Major categories that need to be included are:

- Identification of hole size, location, and ignition conditions,
- Inclusion of site specific conditions - wind, topography, waves, currents, structural interactions,
- Fuel spill and spread assumptions, and
- Gas dispersion assumptions with wind conditions, terrain, and obstacle considerations

Analyses that do not include these categories will not be able to identify accurately the risks and hazards to public safety and property.

A wide range of simplified models and approaches exists, and the applicability to LNG spills and comparisons with LNG spill data has been previously conducted, as discussed in

Appendix C. While these studies provide insight into the appropriate models to use, several additional factors should be considered in applying these models to a specific problem. These include:

- Model documentation and support – assumptions and limitations, comparison with data, model change control and upgrade information, and user support;
- Appropriate modeling of the physics of a spill – time-varying spill and dispersion analysis, vapor and pool ignition and burning, and water and fire impact on LNG spill spread and vaporization;
- Modeling of the influence of environmental conditions (wind, waves, water current, air, and water temperature, and humidity) on liquid and vapor dispersion, flame tilt, and spill and fire dynamics; and
- Peer review of applications of models, and peer review of the applications of the models.

By considering these factors, many existing models and tools can be used in many cases to provide adequate, general guidance on potential hazards associated with an LNG spill over water.

The fire hazards addressed in this study have been evaluated using integral or similarity models that can be readily applied in practice. Simplified models with the appropriate input parameters can be used with reasonable confidence for calculating the heat flux to objects at a long distance (more than the LNG pool diameter) from a fire that is not heavily influenced by nearby structures [Gritzo and Nicolette, 1997]. Under such conditions, the main uncertainties in the simplified models are due to 1) the inability of these models to represent fires at very large (50 m or more in diameter) scales, and 2) uncertainty in the input parameters required by these models.

Where an analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain, buildings, or structures can occur, modern, validated, CFD models can be applied to assess spill, dispersion, vaporization, and fire hazards to improve analysis of site-specific conditions. CFD models solve the fluid dynamics equations, coupled with the reacting flow properties that result in the thermal hazard posed by fires. Rather than treating the shape of the flames as cylindrical (as assumed by simple or integral models), validated CFD-based techniques predict the flame shape as influenced by adjacent objects and structures. Comparison with experimental data indicates that the point source model and the solid flame model do not accurately predict heat flux levels when the pool is non-uniform, such as would occur when there is object interaction. As such, CFDs are better able to provide predictions of the heat flux to engulfed structures and, therefore, can be used to analyze cascading effects where hazards might induce additional failures and subsequent fire hazards. Because they include additional physics, fewer input parameters are required and, once validated, they can better represent fires at very large scales.

Table 22: Importance of Parameters/Assumptions for Assessing LNG Spills/Fires/Explosions

ASSESSMENT OF SCENARIO	ESTIMATED IMPACT ON HAZARDS
Specification Of Initial Conditions	
Hole size and location	High
Ignition potential	High
Specification Of Boundary Conditions	
Wind/atmospheric conditions	High
Topography of site	High
Pool surface and properties (waves, thermodynamic properties, etc.)	High
Nearby structures	Med
Modeling Assumptions And Features	
Fuel spill	Med
Simple hole	Med
Vaporization enhanced by turbulence mixing	Med-High
Spread Model: smooth surface	High
Spread Model: fuel composition	Med-Low
Spread Model: atmospheric conditions	High
Spread Model: RPT	Med
Dispersion	
Dense gas	High
Under vs. above water release	High
Atmospheric conditions	High
Terrain/obstacles	High
Ignition	
Fuel composition	High
Ignition time of event (from puncture or impact)	High
Fire	
Burning rate	Med-High
Surface emissive power	High
Flame shape at large scale	High
Obstacles	High
Atmospheric conditions	High
Fuel composition	High

Detailed models require more computational capability and user expertise; therefore, they are less desirable for widespread application. However, validated, detailed models can be used to develop correction factors for simplified models that can, in turn, be widely employed with confidence to assess hazards. These tools can also be used to explore the potential passive (such as vapor barriers or firebreaks) or active (such as water spray) mitigation techniques.

Development of validated CFD models will require implementation of equations to represent phenomena, including: 1) the dynamics of cryogenic liquids, including evaporation and spread on water, and 2) the mixing and burning of low temperature natural gas vapor in very large plumes. These models must be verified (i.e. ensure that the equations are being solved correctly) and validated (i.e. ensure that the right equations are being solved for the application of interest) through analysis efforts and comparisons with high quality data.

Validation of detailed models for LNG applications is beyond the scope of this study; but such models have been applied in numerous other cases to evaluate large fire hazards from liquid hydrocarbons such as jet fuel [Gritzo and Nicolette 1997] [Suo-Antilla and Gritzo 2001] [Gritzo and Nicolette 1998]. The essential features of the validation process have been documented in the literature [Gritzo et al., 2004].

Our evaluation suggests that modern, validated CFD models should be further refined and used as appropriate to improve site-specific thermal hazard and consequence analyses where interaction with terrain, buildings, or other structures might occur. Table 23 presents various, CFD models that could be used for the listed applications. These types of models can address complex geometries, and include additional physical modeling capabilities that allows them to be more easily extrapolated to larger spills.

Table 23: Suggested Models for Enhanced Spill, Dispersion, and Fire Dynamics Analyses

APPLICATION	SUGGESTED MODELS & APPLICATIONS
Tank Emptying	Modified orifice model that includes the potential for LNG leakage between hulls
Spreading	Free-surface CFD code (e.g. application extension of FLOW-3D, STORM/CFD2000)
Dispersion	CFD code (e.g. FEM3C, FLUENT, CFX, Fuego)
Fire	CFD code (e.g. FLACS, CFX, FDS, Phoenics, Kameleon, Vulcan, and Fuego)

7.2 Safety Analysis Guidance and Recommendations

The positive safety record of LNG vessels and the LNG transportation industry over the past 30 years is indicative of the extensive attention to safety being conducted through the cooperation of LNG importers, LNG transporters, the U.S. Coast Guard, emergency management and response teams, and by the risk and safety management considerations employed to improve LNG shipping and handling operations. Such considerations include:

- Double-hulled ship designs,
- Appropriate safety systems to reduce the potential for damage,
- Security management and escort of LNG ships operating in harbors and waterways, and
- Vessel movement and control zones (e.g., safety and security zones) to reduce the potential for impacts with other ships or structures.

These efforts have all significantly prevented or mitigated the potential for an accidental LNG cargo tank breach. While existing safety measures have been very effective, intentional attempts to breach an LNG cargo tank are now being considered as potential spill scenarios. Many recent studies have begun to consider both types of events and assess the safety and hazard issues of a subsequent fire or explosion of the spilled LNG. To date, most of these studies usually concentrate on postulating a spill scenario and calculating potential hazards and consequences without considering the likelihood of such an event. In addition, they often do not include experimental validation of the assumptions or analyses for the conditions postulated, nor do they consider prevention or mitigation strategies that could reduce the impact or hazards of the postulated events.

The following three conclusions provide a summary of the major results of an LNG cargo tank breach, spill, and dispersion, and the results of a hazard evaluation analysis developed from what we think are credible accidental and intentional spill scenarios.

1. The most significant impacts to public safety and property exist within approximately 500 m of a spill, with lower impacts at distances beyond 1600 m, even for very large spills.
2. Under certain conditions, it is possible that multiple LNG cargo tanks could be breached, either as a result of an initial event, or as a consequence of cryogenic or fire-induced structural damage.
3. Based on this possibility, multiple breach and cascading LNG cargo tank damage scenarios were analyzed. While possible under certain conditions, they are likely to involve no more than two to three cargo tanks at any one time. These conditions will not greatly change the hazard ranges noted in General Conclusion Number 1 above, but will increase expected fire duration.

7.2.1 Accidental Breach Scenario Conclusions

1. Accidental LNG cargo tank damage scenarios exist that could potentially cause an effective breach area of 0.5 to 1.5 m^2.
2. Due to existing design and equipment requirements for LNG carriers, and the implementation of navigational safety measures such as traffic management schemes and safety zones, the risk from accidents is generally low.
3. The most significant impacts to public safety and property from an accidental spill exist within approximately 250 m of a spill, with lower impacts at distances beyond approximately 750 m from a spill.

7.2.2 Intentional Breach Scenario Conclusions

1. Several credible, intentional LNG cargo tank damage scenarios were identified that could initiate a breach of 2 m^2 –12 m^2 with a probable nominal size of 5 – 7 m^2.
2. Most of the intentional damage scenarios identified produce an ignition source such that an LNG fire is likely to occur immediately.
3. Some intentional damage scenarios could result in vapor cloud dispersion, with delayed ignition and a fire.
4. Several intentional damage scenarios could affect the structural integrity of the vessel or other LNG cargo tanks due to ignition of LNG vapor trapped within the vessel. While possible under certain conditions, these scenarios are likely to involve no more than two to three cargo tanks at any one time, as discussed in Sections 4 and 5.
5. Rapid phase transitions are possible for large spills. Effects will be localized near the spill source and are not expected to cause extensive structural damage.

6. The potential damage from spills to critical infrastructure elements such as bridges, tunnels, industrial/commercial centers, LNG unloading terminals and platforms, harbors, or populated areas, can be significant in high hazard zones.
7. In general, the most significant impacts from an intentional spill on public safety and property exist within approximately 500 m of a spill, with lower impacts at distances beyond approximately 1600 m from a spill, even for very large spills.

7.3 Risk Management Guidance for LNG Spills over Water

Based on this study, guidance is provided to support performance-based LNG spill prevention, spill management, and hazard evaluations for marine LNG import facilities. The consideration of operations, safety precautions, prevention strategies, and consequence modeling and evaluation approaches should be focused on reducing the risks of a potential LNG spill as identified and developed with public safety organizations, public officials, and appropriate stakeholders for a specific site and conditions..

The following guidance is provided to assist risk management professionals, emergency management and public safety officials, and other port security stakeholders in developing and implementing appropriate risk management strategies and processes.

7.3.1 General Risk Management Guidance

For both accidental and intentional spills, we recommend the following:

- The use of effective security and risk management operations that include enhanced interdiction, detection, delay procedures, risk management procedures, and coordinated emergency response measures, can reduce the risks from an accidental or intentional breaching event;
- Implemented risk management strategies should be based on site-specific conditions and the expected impact of a spill on public safety and property. Less intensive strategies would often be sufficient in areas where the impacts of a spill could be low.
- Where analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain or structures can occur, modern, validated computational fluid dynamics models can be used to improve analysis of site-specific hazards.

7.3.2 Guidance on Risk Management for Accidental Spills

Zone 1

These are areas in which LNG shipments transit narrow harbors or channels, pass under major bridges or over major tunnels, or come within approximately 250 meters of people and major infrastructure elements, such as military facilities, population and commercial centers, or national icons. Within this zone, the risk and consequences of an accidental LNG spill could be significant and have severe negative impacts. Thermal radiation could pose a severe public safety and property hazard and can damage or significantly disrupt critical infrastructure located in this area.

Risk management strategies for LNG operations should address both vapor dispersion and fire hazards. Therefore, the most rigorous deterrent measures, such as vessel safety or security zones, waterway traffic management schemes, and establishing positive control over the vessel are options to be considered as elements of the risk management process. Coordination among all port security stakeholders is essential. Incident management and emergency response measures should be carefully evaluated to ensure adequate resources (i.e., firefighting, salvage, etc.) are available for consequence and risk mitigation.

Zone 2

These are areas in which LNG shipments and deliveries occur in broader channels or large outer harbors, or within approximately 250 m – 750 m of major critical infrastructure elements like population or commercial centers. Thermal radiation transitions to less severe hazard levels to public safety and property.

Within Zone 2, the consequences of an accidental LNG spill are reduced and risk reduction and mitigation approaches and strategies can be less extensive. In this zone, risk management strategies for LNG operations should focus on approaches dealing with both vapor dispersion and fire hazards. The strategies should include incident management and emergency response measures such as ensuring areas of refuge (enclosed areas, buildings) are available, development of community warning signals, and community education programs to ensure persons know what precautions to take.

Zone 3

This zone covers LNG shipments and deliveries that occur greater than approximately 750 m from major infrastructures, population/commercial centers, or in large bays or open water, where the risks and consequences to people and property of an accidental LNG spill over water are minimal. Thermal radiation poses lesser risks to public safety and property.

Within Zone 3, risk reduction and mitigation strategies can be significantly less complicated or extensive. Risk management strategies should concentrate on incident management and emergency response measures that are focused on dealing with vapor cloud dispersion. Measures should ensure areas of refuge are available, and community education programs should be implemented to ensure that persons know what to do in the unlikely event of a vapor cloud.

7.3.3 Guidance on Risk Management for Intentional LNG Spills

Zone 1

These are areas where LNG shipments occur in either narrow harbors or channels, pass under major bridges or over tunnels, or come within approximately 500 meters of major infrastructure elements, such as military facilities, population and commercial centers, or national icons. In these areas, the risk and consequences of a large LNG spill could be significant and have severe negative impacts. Thermal radiation can pose a severe public safety and property hazard and can damage or significantly disrupt critical infrastructure located in this area.

Risk management strategies for LNG operations should address vapor dispersion and fire hazards. The most rigorous deterrent measures, such as vessel safety or security zones, waterway traffic management schemes, and establishing positive control over the vessel are elements of the risk management process. Coordination among all port security stakeholders is essential. Incident management and emergency response measures should be carefully evaluated to ensure adequate resources (i.e., firefighting, salvage, etc.) are available for consequence and risk mitigation.

Zone 2

These are areas in which LNG shipments and deliveries occur in broader channels or large outer harbors, within approximately 500 m – 1.6 km of major critical infrastructure elements, such as population or commercial centers. Within Zone 2, the consequences of even a large LNG spill are reduced. Thermal radiation transitions to less severe hazard levels to public safety and property.

Risk management strategies for LNG operations that occur in this zone should focus on fire and vapor dispersion hazards. The strategies should include incident management and emergency response measures such as ensuring areas of refuge (enclosed areas, buildings) are available, development of community warning signals, and community education programs to ensure persons know what precautions to take.

Zone 3

This zone covers LNG shipments and deliveries that occur greater than approximately 1.6 km from major infrastructures, population/commercial centers, or in large bays or open water, where the risks and consequences to people and property of a large LNG spill over water are minimal. Thermal radiation poses lesser risks to public safety and property. Within Zone 3, risk reduction and mitigation strategies can be less complicated or extensive than Zones 1 and 2. Risk management strategies should focus on incident management and emergency response measures for dealing with vapor cloud dispersion. Measures should ensure that areas of refuge are available, and community education programs should be implemented to ensure that persons know what to do in the unlikely event of a vapor cloud.

7.4 Key Conclusions: Safety Analysis and Risk Management

This study provides guidance on performance-based risk management approaches for analyzing and managing the threats, hazards, consequences, and risks to public safety and property due to an LNG spill over water. Based on the results of this study, we provide the following key conclusions:

1. The system-level, risk-based guidance developed in this report, though general in nature (non site-specific), can be applied as a baseline process for evaluating LNG operations where there is the potential for LNG spills over water.
2. A review of four recent LNG studies showed a broad range of results, due to variations in models, approaches, and assumptions. The four studies are not consistent and focus only on consequences rather than both risks and consequences. While consequence studies are important, they should be used to support comprehensive, risk-based management and planning approaches for identifying, preventing, and mitigating hazards to public safety and property from potential LNG spills.
3. Risks from accidental LNG spills, such as from collisions and groundings, are small and manageable with current safety policies and practices.

4. Risks from intentional events, such as terrorist acts, can be significantly reduced with appropriate security, planning, prevention, and mitigation.
5. This report includes a general analysis for a range of intentional attacks. The consequences from an intentional breach can be more severe than those from accidental breaches. Multiple techniques exist to enhance LNG spill safety and security management and to reduce the potential of a large LNG spill due to intentional threats. If effectively implemented, these techniques could significantly reduce the potential for an intentional LNG spill.
6. Management approaches to reduce risks to public safety and property from LNG spills include operation and safety management, improved modeling and analysis, improvements in ship and security system inspections, establishment and maintenance of safety zones , and advances in future LNG off-loading technologies. If effectively implemented, these elements could reduce significantly the potential risks from an LNG spill.
7. Risk identification and risk management processes should be conducted in cooperation with appropriate stakeholders, including public safety officials and elected public officials. Considerations should include site-specific conditions, available intelligence, threat assessments, safety and security operations, and available resources.
8. While there are limitations in existing data and current modeling capabilities for analyzing LNG spills over water, existing tools, if applied as identified in the guidance sections of this report, can be used to identify and mitigate hazards to protect both public safety and property. Factors that should be considered in applying appropriate models to a specific problem include: model documentation and support, assumptions and limitations, comparison with data, change control and upgrade information, user support, appropriate modeling of the physics of a spill, modeling of the influence of environmental conditions, spill and fire dynamics, and peer review of models used for various applications. As more LNG spill testing data are obtained and modeling capabilities are improved, those advancements can be incorporated into future risk analyses.
9. Where analysis reveals that potential impacts on public safety and property could be high and where interactions with terrain or structures can occur, modern, validated computational fluid dynamics (CFD) models can be used to improve analysis of site-specific hazards, consequences, and risks.
10. LNG cargo tank hole sizes for most credible threats range from two to twelve square meters; expected sizes for intentional threats are nominally five square meters.
11. The most significant impacts to public safety and property exist within approximately 500 m of a spill, due to thermal hazards from fires, with lower public health and safety impacts at distances beyond approximately 1600 m.
12. Large, unignited LNG vapor releases are unlikely. If they do not ignite, vapor clouds could spread over distances greater than 1600 m from a spill. For nominal accidental spills, the resulting hazard ranges could extend up to 1700 m. For a nominal intentional spill, the hazard range could extend to 2500 m. The actual hazard distances will depend on breach and spill size, site-specific conditions, and environmental conditions.

13. Cascading damage (multiple cargo tank failures) due to brittle fracture from exposure to cryogenic liquid or fire-induced damage to foam insulation was considered. Such releases were evaluated and, while possible under certain conditions, are not likely to involve more than two or three cargo tanks for any single incident. Cascading events were analyzed and are not expected to greatly increase (not more than 20%-30%) the overall fire size or hazard ranges noted in Conclusion 11 above, but will increase the expected fire duration.

APPENDIX A
RECENT LNG SPILL MODELING REVIEW

1 INTRODUCTION

This appendix reviews four recent reports developed over the past two years that assess the impacts of large LNG spills over water. A summary of the assumptions, models, and results of the analyses in each of the studies is presented first. Next, the differences in the studies are highlighted relative to the influence and impact the various assumptions and models have on the outcome and results. The review identifies potential concerns and uncertainties with each study and provides recommendations for the development of interim analysis techniques and processes to better and more consistently assess the consequences and hazards of LNG spills.

Four studies were evaluated to assess whether they provided a definitive determination of the lateral extent and thermal hazards of a large-scale release of LNG from a tanker over water. The studies evaluated were:

- Lehr, W. and Simecek-Beatty, D. "Comparison of Hypothetical LNG and Fuel Oil Fires on Water." Report by the National Oceanic and Atmospheric Administration (NOAA), Office of Response and Restoration, Seattle, WA, 2003, DRAFT [Lehr and Simicek-Beatty 2003].
- Fay, J.A. "Model of spills and fires from LNG and oil tankers." Journal of Hazardous Materials, B96-2003, 171-188, 2003 [Fay 2003].
- "Modeling LNG Spills in Boston Harbor." Copyright© 2003 Quest Consultants, Inc., 908 26th Ave N.W., Norman, OK 73609; Letter from Quest Consultants to DOE (October 2, 2001); Letter from Quest Consultants to DOE (October 3, 2001); and Letter from Quest Consultants to DOE (November 17, 2003) [Quest 2003].
- "Liquefied Natural Gas in Vallejo: Health and Safety Issues." LNG Health and Safety Committee of the Disaster Council of the City of Vallejo, CA, January 2003 [Vallejo 2003] [Koopman 2004].

Following is a summary of the major assumptions, models, and results concerning the potential hazards from an LNG spill from each of the four reports reviewed.

2 ASSUMPTIONS, MODELS, AND RESULTS FOR EACH STUDY

2.1 Lehr Study

The report provided by *Lehr* contrasts accidental spills from ships carrying refined petroleum products versus LNG [Lehr and Simicek-Beatty 2003]. Quantitative estimates are made of spread rate, maximum pool area, burn rate, burn duration, and effective thermal radiation. The following provides a summary of the assumptions, models, and results from this report, for LNG spills only.

2.1.1 Breach Scenario Assumptions

No assumptions were made regarding how a spill might occur.

2.1.2 Spreading Model

The spread rate model does not take into account the mass loss due to evaporation while the pool is spreading if ignition does not occur immediately. The pool radius is a function of spill rate for continuous spills or volume spilled for an instantaneous spill.

If ignition occurs immediately and the spill is instantaneous, an approximate relation is used, which is a function of minimum pool thickness, burn regression rate, and source leak rate.

The pool is spreading on a quiescent surface. Waves are not considered.

Viscosity and surface tension of the LNG are neglected.

The model assumes that the LNG will spread in a uniform circle.

2.1.3 Dispersion Model

Dispersion is not considered.

2.1.4 Flame model

The flame is modeled as a circular cylinder that radiates upward and uniformly over the cylinder's surface. Flame tilt due to wind is not considered. Flame height is approximate according to the empirical correlation by Thomas [Thomas 1965].

Incident thermal radiation to an object is determined by calculating the product of the average emissive power at the flame surface, an atmospheric transmission factor, and a geometric view factor. An average emissive power is calculated by an empirical correlation taken from the Society of Fire Protection Engineers Handbook.

The transmission factor is calculated by a relation from Glasstone and Dolan, who base their work on thermal radiation from a nuclear bomb explosion [Glastone and Dolan 1977].

Burn regression rate is according to values give from experiments performed by Raj [Raj et al. 1979]. The rates were found to vary from 0.4 to 1 mm/s.

2.1.5 Results

The results are given for one example, an instantaneous LNG spill of 500 m^3. The pool is burning while it is spreading.

A maximum spread velocity of 1 m/s results after a few seconds.

The maximum burn time is approximately two – three minutes.

At maximum radius and flame height, the radiation fraction of the heat of combustion is 0.21.

At a distance of 500 m from the pool's edge, a maximum average radiant heat flux of 7 kW/m^2 is obtained.

The pool radius calculated was not stated.

2.2 Fay Study

Fay provided an analysis of the spreading of LNG, duration of a pool fire burn, and heat release. These quantities are expressed in terms of the cargo tank geometric properties [Fay 2003]. The following provides a summary of the assumptions, models, and results from this analysis.

2.2.1 Breach Scenario Assumptions

No assumptions were made regarding how a spill might occur.

2.2.2 Spreading Model

The spreading model includes the vaporization of the pool as the pool spreads.

The pool is assumed to spread in the shape of a uniform semi-circle.

The pool is spreading on a quiescent surface. Waves are not considered.

Viscosity and surface tension of the LNG are neglected.

Breaches above and below the water's surface are considered.

A value of (5 –7) x 10^{-4} m/s is used for the vaporization rate of LNG on water.

2.2.3 Dispersion Model

Dispersion is not considered.

2.2.4 Flame model

The flame is not modeled.

Radiant flux to an object is approximated by taking a fraction of the heat release rate, averaged over the fire's duration, and dividing by the square of the distance to an object. The radiation flux heat release rate fraction is assumed as 0.15.

2.2.5 Results

The example given assumes 14,300 m^3 of LNG from a single tank spills onto the water. The values for maximum pool area are given as a function of puncture area. A total vaporization rate of 8 x 10^{-4} m/s is used to account for heating from the water below and fire above the LNG.

For the equivalent puncture area given in the *Quest* report of 19.63 m^2 (5 m dia. hole), the maximum pool radius calculated by *Fay* is 252 m, assuming the shape is a circle. For a semicircle, the radius is 357 m.

The burn duration for this rupture area and pool area is reported as 3.3 minutes.

The distance from the fire to an object at which the radiant flux is 5 kW/m^2 is 1.9 km.

2.3 Quest Study

Quest conducted an analysis of the consequence of a potential release of LNG from an LNG tanker at Boston Harbor [Quest 2003]. They considered how a potential release could occur and provided an analysis of the spreading of LNG, as well as the flammable hazards after the release. The following provides a summary of the major assumptions and models that *Quest* used, and its analytical conclusions.

2.3.1 Breach Scenario Assumptions

The scenario considered is a ship-to-ship collision in the outer harbor of Boston. It is assumed that the tanker has five LNG membrane tanks holding 25,000 m^3 each, to allow for a total holding capacity of 125,000 m^3. The ships separate after the collision.

A hole results from the collision just above the waterline in one of the five tanks only. The largest hole size that results is five meters.

LNG at a pressure of 1.45 psig and temperature of –160.5 C leaks from the hole. The LNG is composed of 96.97% methane, 2.62% ethane, 0.316% propane, and trace amounts of other compounds.

No explosions occur.

2.3.2 Spreading Model

The LNG will spill onto the water and spread. A simple orifice model is used to determine that it will take two minutes for the ruptured tank to empty to the waterline, spilling 12,500 m^3 of LNG.

The model assumes that the LNG will spread in a uniform circle.

The spread rate is a function of spill rate, vaporization rate, and pool radius.

A value of 0.18 kg/m^2 is used for the vaporization flux of LNG on water.

Viscosity and surface tension of the LNG are neglected.

Waves will affect the spreading. This feature is accounted for by assuming that the waves are a simple cycloid shape. The wave effect on spreading is incorporated through a conditional statement at the boundary of the pool; namely, the pool will stop spreading once the LNG drops below 60% of the wave height. The effect of waves also increases the vaporization flux by 27% due to the increase in surface area.

Three averaged wave heights, taken from NOAA Boston Harbor buoy data, are considered: 0.575 m, 0.682 m, and 1.24 m.

2.3.3 Dispersion Model

A vapor cloud will form and disperse. This was modeled by using Quest's software dispersion code 'CANARY,' which accounts for transient release rates, initial velocity of the released gas, initial dilution of the vapor, thermodynamics, gas cloud density relative to air, and mixture behavior. Another code, DEGADIS, was also used for comparison.

Three different wind speeds were considered: 1.5 m/s (F stability class), 5.0 m/s (D stability class), and 9.0 m/s (D stability class). Stability class refers to atmospheric stability. F class is extremely stable and results in the greatest amount of time for the released gases to mix with the atmosphere. D class is neutrally stable; thus mixing will occur faster in class D than in F class.

2.3.4 Flame model

The fuel is assumed to ignite because of the collision.

The flame is modeled as an elliptical cylinder; thus, a tilted flame. The base of the flame is assumed to increase due to flame drag and is approximated by an empirical correlation [Moorehouse 1982]. Flame angle is calculated by using an empirical formula by Welker and Sliepcevich [Welker and Sliepcevich 1970]. Flame length is approximated by an empirical correlation [Dorofeev et al. 1991]. The flame is divided into two zones: a clear zone with no smoke, and a zone in which a fraction of the flame is obscured by smoke. The length of the clear zone is determined by an empirical correlation [Pritchard and Binding 1992].

2.3.5 Results

Quest concluded the following values from its analyses:

Table 24: Model Results (Quest Study)

WIND SPEED (m/s)	WAVE HEIGHT (m)	MAXIMUM LNG RADIUS	TOTAL TIME TO BURN SPILL (min)	DISTANCE TO:		
				22.1 kW/m^2	12.6 kW/m^2	4.73 kW/m^2
1.5	0.575	78 m (257 ft)	14.3	226 m (740 ft)	309 m (1,015 ft)	497 m (1,630 ft)
5.0	0.672	73 m (239 ft)	16.6	270 m (885 ft)	351 m (1,150 ft)	531 m (1,740 ft)
9.0	1.24	55 m (180 ft)	28.6	281 m (920 ft)	349 m (1,145 ft)	493 m (1,615 ft)

At these radiant flux levels, the following occur:

Table 25: Impact of Radiation (Quest Study)

22.1 kW/M^2	Structural steel weakens after prolonged exposure to this flux level.
12.6 kW/M^2	Vapors evolving off of a wooden structure might ignite after several minutes of exposure to this flux level if ignition source is present
4.73 kW/m^2	Second-degree skin burns are possible after 30-seconds exposure to this flux level.

For the dispersion calculations of the vapor cloud:

Table 26: Dispersion Calculations (Quest Study)

WIND SPEED (m/s)	STABILITY CLASS	MAXIMUM LNG RADIUS	DISTANCE TO LOWER FLAMMABILITY LIMIT	
			Canary	Degadis
1.5	F	80 m (261 ft)	4,030 m (13,220 ft)	3,400 m (11,155 ft)
5.0	D	73 m (239 ft)	1,050 m (3,445 ft)	1,900 m (6,230 ft)
9.0	D	55 m (180 ft)	340 m (1,115 ft)	1,100 m (3,610 ft)

2.4 Vallejo Study

This study is specific to a particular locale, which includes land and marine facilities for a potential LNG import facility [Vallejo 2003]. The *Vallejo* authors discuss a wide range of initiating events, from accidents to natural events to malevolent acts, and assess the qualitative likelihood of each; but no spill analysis is tailored to different initiating events. The report also includes ideas for mitigation options to enhance safety. Ronald P. Koopman retired from Lawrence Livermore National Laboratory provided the dispersion and thermal hazard results. The report also provides the analysis and results performed by *Quest*. The following pertains only to the work performed by R. P. Koopman. [Koopman 2004]

2.4.1 Breach Scenario Assumptions

The report discusses a variety of ways that a breach to an LNG cargo tank can occur, such as terrorism, operational errors, and maritime accidents. It was not stated how a rupture occurs for the example calculations given.

2.4.2 Spreading Model

Both one-meter and five-meter diameter holes in one 25,000 m^3 LNG ship tank were analyzed. The National Ocean Atmospheric Administration's code, ALOHA (Aerial Locations of Hazardous Atmospheres), was used to calculate the spill from the ship tank. In 6 min., 14,300 m^3 were spilled from the five-meter diameter hole and in 35 min from the one-meter diameter hole. The five-meter diameter hole resulted in a pool with a maximum area of 110,000-130,000 m^2. Vaporization rates of $5x10^{-4}$ m/s were used for evaporation from the water alone, and $8x10^{-4}$ m/s when fire was present.

2.4.3 Dispersion Model

The Lawrence Livermore National Laboratory's SLAB atmospheric dispersion model for denser than air releases were used for the dispersion calculations. Dispersion calculations were performed for two different wind speeds and stability class conditions: 2 m/s (F stability class) and 5 m/s (D stability class). Calculations were performed for two different hole sizes, 1 and 5 meters in diameter.

2.4.4 Flame Model

A pool fire was considered the result due to ignition of 14,300 m^3 of LNG from a tanker. Distances cited were based on a point source model. Attenuation due to atmospheric water vapor was not included. A fireball calculation was also performed, but for a land-based storage tank. Vapor cloud fires were also discussed; but no calculations were performed.

2.4.5 Results:

Pool fire heat radiation results:

Table 27: Fire Heat Radiation Results (Vallejo Study)

HOLE SIZE (m)	DISTANCE TO RADIANCE FLUX LEVEL OF:		
	30 kW/m^2	17 kW/m^2	5 kW/m^2
5 (16.4 ft)	0.35 miles (563 m)	.5 miles (804 m)	0.8 miles (1287 m)

Dispersion calculations of the vapor cloud results:

Table 28: Vapor Cloud Dispersion Calculations (Vallejo Study)

HOLE SIZE DIAMETER (m)	WIND SPEED (M/S)	PASQUILL-GIFFORD ATMOSPHERIC STABILITY	DISTANCE TO LOWER FLAMMABILITY LIMIT miles (meters)*
5	2	F	2.8 miles (4506 m)
5	5	D	1.5 miles (2414 m)
1	5	D	0.7 miles (1126 m)

*Does not consider the limiting effect of topography

3 SUMMARY OF LNG SPILL ASSUMPTIONS AND RESULTS FROM EACH STUDY

Tables 29 and 30 and Figure 6 summarize both the assumptions and the results of each of the reports reviewed.

Table 29: Summary of Study Assumptions

STUDY	TIME TO EMPTY (min)	VAPORIZES DURING SPREAD	WAVE EFFECTS INCLUDED	SHAPE OF POOL	IGNITION TIME	FLAME MODEL	COMBUSTION MODE	IGNITION OCCURS AT POOL, NOT IN VAPOR CLOUD
Lehr	Instantly	Yes	No	Circle	Instantly upon release	Solid cylinder	Diffusion flame; No explosion	Yes
Fay	Varies with hole size	Yes	No	Semi-circle	Instantly upon release	Point source	Diffusion flame; No explosion	Yes
Quest	2	Yes	Yes	Circle	Instantly after spread	Solid cylinder; including tilt for wind effects	Diffusion flame; No explosion	Yes
Vallejo	Varies with hole size	Yes	No	Circle	Instantly upon release	Point Source	Diffusion flame; No explosion	Yes

Table 30: Summary of Study Results

STUDY	FUEL SPILL VOLUME (m^3)	AREA OF FUEL SPILL (m^2)	"SKIN BURN" DISTANCE[a] (m)	"PAPER IGNITION" DISTANCE[b] (m)	FIRE DURATION (min)
Lehr	500 (hole area not specified)	Not reported	500[c]	Not reported	2-3
Fay[e]	14,300 (20m^2 hole area)	200,000	1900	930	3.3
Quest	12,500 (20m^2 hole area)	9503	490 [d]	281[d]	28.6
Vallejo	14,300 (20m^2 hole area)	120,000	1290	660	9.0

[a]A thirty-second exposure to heat levels of 5 kW/m^2 causes second-degree skin burns(blisters) at this distance.
[b]A seventeen-second exposure to heat levels of 22 kW/m^2 causes newspaper to ignite at this distance. (Ref.: SFPE Handbook of Fire Protection Engineering, 2nd ed., National Fire Protection Association, (1995).
[c] Distance from edge of spill
[d]Assuming a wind speed of 9 m/s (20 mph).
[e] Considers a range of hole sizes. This size chosen for comparison.

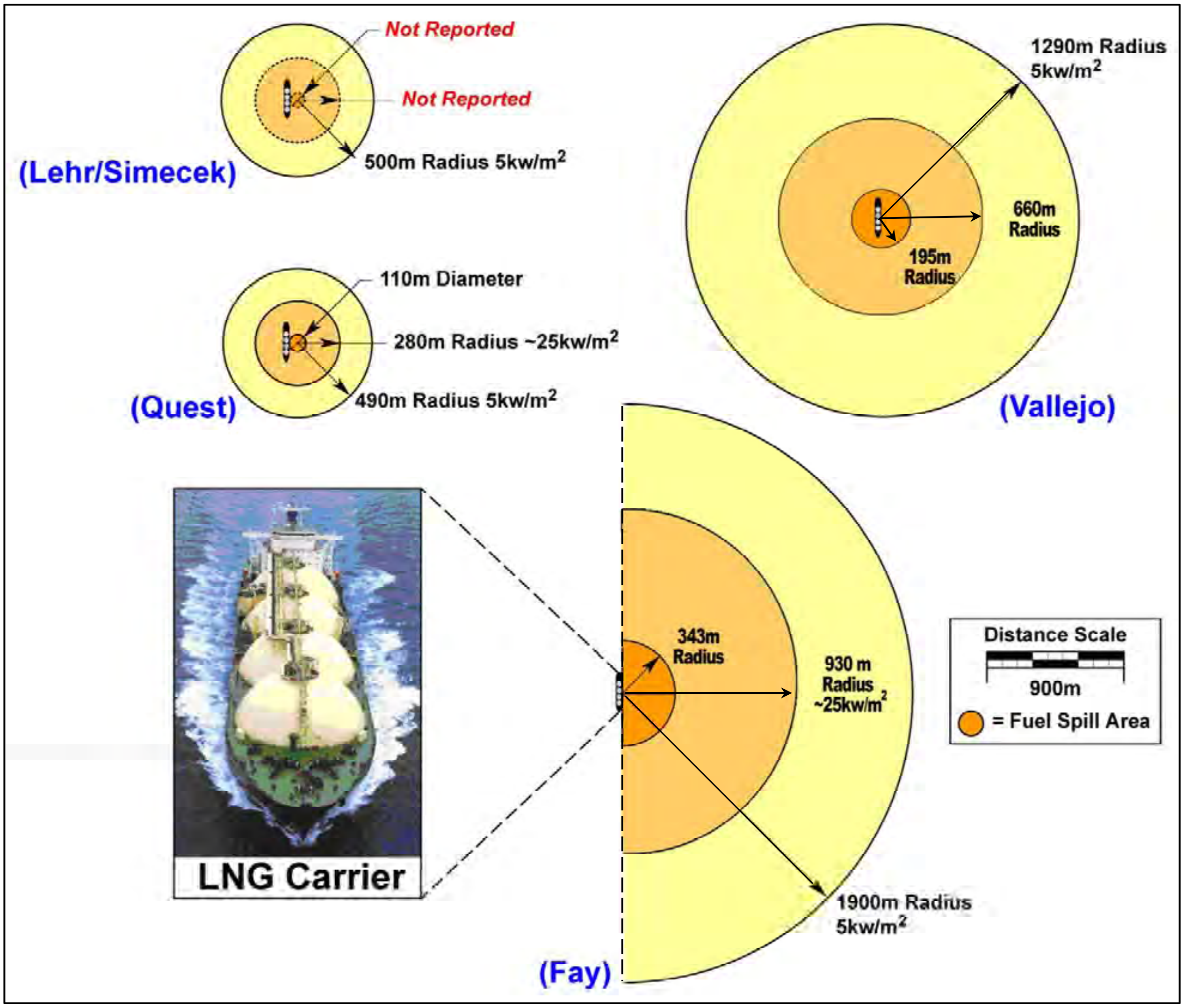


Figure 6. Graphical Summary of the Results of the *Lehr, Fay, Quest & Vallejo* Studies
(Yellow = 5kW/m^2; lt. Orange = 25 kW/m^2; dk. Orange = fuel spill radius)

4 WHY THE STUDIES DIFFER

The following discussion provides comparisons among the different reports and explains why different results are obtained. It is not intended to be an assessment of the merit or validity of the reports.

It is difficult to provide a direct comparison of the results among the reports because each provides a different scenario and/or example assumptions. The example case given by *Lehr* is especially difficult to compare to the other three reports because of the much lower amount of LNG spilled. Pool diameter, radiant flux, and burn duration will depend upon the scenario or example assumptions used, as evident from the reports. Obviously, a larger pool fire would result if all of the five cargo tanks were ruptured due to a larger amount of fuel spilled.

Direct comparison is also difficult due to the lack of information in these reports. The *Lehr* and *Vallejo* reports do not state the pool area values they calculated. *Quest* does not provide surface emission powers used in their heat transfer calculations. The *Vallejo* report does not provide information on the flame model that was used.

In *Quest,* the time of ignition of the pool is unclear in the analysis. *Quest* states that a higher effective vaporization rate results due to back-radiation from the pool flame. When this is included in their model, it reduces the time to vaporize the pool, but not the pool radius. Apparently, the pool is allowed to fully spread with the effect of waves included before ignition results. This contradicts the statement made that ignition occurs because of the collision, which would indicate immediate ignition.

In order to obtain some idea of the effect of including vaporization from back-radiation on pool radius, consider a steady-state situation in which the flow rate into the pool is balanced by both the flow rate provided through vaporization from heating from below by the water and by heating from above by the flame. If an average flow rate of 40,056 kg/s (obtained from *Quest*) and a vaporization rate of 8 x 10^{-4} m/s (.346 kg/m^2 s) are used, a pool radius of 192 m results. Thus, reducing the radius below that of *Quest*'s value of 253 m before the effect of waves is included. This is an approximation because, in reality, the flow rate decreases with time; whereas this example assumes an infinite source to provide a steady flow rate.

Of the reports, it is possible to somewhat compare the results given for pool area by *Quest* and *Fay*, because the amount spilled is similar; 12,500 versus 14,300 m^3 of LNG, and both can be compared for equivalent hole sizes. The value given for pool radius by *Quest*, before including the effect of waves, is 253 meters. *Fay* reports a value of 252 m, if the radius is calculated based upon the shape of a circle. Thus, the two reports compare favorably for pool area when waves are not considered. *Quest* found that, by including the effect of waves, the pool radius decreased to 55 m for the high wind case. This is why *Quest* reports a significantly different value for pool radius. *Fay* considered a perfectly smooth surface upon which the fuel spreads, while *Quest* considered the impeding action of waves.

The value reported by *Quest* and *Fay* for the distance required for an object to receive a radiant flux of approximately 5 kW/m^2 is significantly different: 493 m versus 1900 m, respectively. One obvious reason for this difference is that *Fay's* analysis predicts a much larger pool fire. For instance, by using the relation that *Fay* used to determine the radiant flux at the distance and pool area given by *Quest*, the distance is 353 m at which the radiant flux is 5 kW/m^2. Thus, pool area will make a significant difference.

Fay also did not model the flame in his analysis. The relation he used provides a crude approximation to the thermal radiation emitted by a pool fire. The radiant flux emitted by a pool fire to an object is dependent upon many factors, such as pool size, fuel type, flame shape, and view factors.

The reports by *Lehr* and *Fay* use reasonable values for the burn rate of LNG. *Quest* does not explicitly provide the value that they used, though it can be inferred that they used a value of approximately 2.1 x 10^{-4} m/s (.09 kg/m^2 s). The range of burning rate values, determined experimentally by other researchers, has been found to be: 3.2 x 10^{-4} m/s (35 m dia.) [Johnson 1992], 2.5 x 10^{-4} m/s (18 m dia.) [Drake and Wesson 1976] and 2.1 – 4.2 x 0^{-4} m/s (30 m dia.) [Mizner and Eyre 1983].

The burn duration of 28.6 minutes given by *Quest* is reasonable, given the pool radius and the amount spilled. It is difficult to check this accurately, because the amount of fuel left after vaporization during spreading is unknown. A burn time of 31.6 minutes results, assuming a mass flux value of 0.3 kg/m^2 s (from heating from water below and heating above), pool radius of 55 m, and 12,500 m^3 of LNG. A longer burn time for this example occurs because it is assumed that all of the LNG spilled is available for burning. For a pool radius of 252 m, a burn time of 1.7 minutes results if 14,300 m^3 is assumed available, and a mass flux of 0.3 kg/m^2 s is assumed. This assumes a pool that is ignited after it spreads to 252 m. *Fay* reports a burn time of 3.3 minutes using a spill volume of 14,300 m^3, 252 m pool radius, and mass flux of 0.345 kg/m^2 s. His burn time differs because it pertains to a pool that is burning while it is spreading.

Thus, there is a trade-off between the size of the fire and burn duration. For fires of increasing size, the burn duration decreases. It is interesting to note that *Quest* reported it took two minutes for 12,500 m^3 of LNG to spill from a five meter diameter hole, and that *Fay*'s result for pool diameter for the same hole size results in a burn time of 3.3 minutes. *Fay*'s spill time would have been longer, because he was considering 14,300 m^3. Thus, the time taken to spill would have been approximately equivalent to the time taken to burn in *Fay*'s example.

Following is a table summary comparing the results of *Quest* and *Fay*:

Table 31: Summary of Results [Quest vs. Fay]

STUDY	HOLE SIZE (m)	VOLUME SPILLED (m^3)	POOL RADIUS; NO WAVES (m)	POOL RADIUS; WAVES (m)	DISTANCE TO 5 kW/m^2	BURN DURATION (min)
Quest	5	12,500	253	55	493 m**	28.6
Fay	5	14,300	252	Not considered	1900 m*	3.3

*Using *Fay*'s combustion model, this value would be 353 m, if the pool had a 55 m radius.
**Based upon 55 m radius pool

5 IDENTIFICATION OF GAPS AND LIMITATIONS IN THE STUDIES

In the context of a comprehensive risk analysis, one needs to overlay onto the event tree in Figure 4 the body of knowledge provided by the four studies. The missing pieces are the gaps identified. It is evident at the highest level that the four reports omit consideration of many aspects within the context of the event tree.

Additionally, the reports do not cover several potential types of consequences not involving LNG ignition (e.g., asphyxiation, cryogenic burns to humans, cryogenic damage to the ship's structure). Thus, several potential consequences of an LNG spill are not considered.

In addition, risk assessment modeling of mitigation of potential harm to people, facilities, or the LNG ships was not provided. Although the scope of this evaluation did not include remediation of the shortcomings within the four studies, it does pose those missing issues and subsequent analysis techniques that should be considered on a site-specific basis.

5.1 LNG Cargo Tank Breach Modeling

All of the studies assumed breach scenarios. Better definition of realistic breach scenarios and LNG tanker breach and spill calculations should be investigated for site-specific conditions evaluated. Specific intentional breach scenarios are not well known; but general scenarios such as hijackings, terrorist attacks, and insider-supported actions are events that have occurred in the past and should be commonly considered. Prevention and mitigation concepts should be considered to address these impacts, especially in high consequence, highly industrialized or highly populated areas.

5.2 LNG Liquid Transport Modeling

Quest's analysis indicates that the effect of waves is significant. Their model, however, is a very simplistic representation of a standing wave. The boundary condition they invoked to account for waves is one-dimensional and has only a bounding effect, rather than an effect that aids in spreading. Models that are more sophisticated should be considered, such that the physics of traveling waves are included. From the experiments by Mizner and Eyre, the pool formed was far from circular, and was more of a 'boom-a-rang' shape. This indicates that the dynamics of waves can indeed have a significant effect on pool spreading.

5.3 LNG Combustion Modeling

All of the reports use very simplified models, solid flame or point source, to determine the radiant heat flux from the flame. Far more sophisticated methods to model the flame are currently available. Due to increased computer capabilities, validated CFD codes exist for chemically reacting flows that have radiation and soot models. These codes also have the capability to model the effect of wind on the flame by invoking a wind boundary condition. Thus, flame tilt due to wind effects can be captured. It is recommended that these codes be used to model the flame, rather than the solid flame or point source models used in these studies.

All the reports assume that the fuel ignites immediately and that only a pool fire results.

As an example of a different combustion scenario, the experiments performed by Mizner and Eyre involved an ignition source 130 meters away from the spill source. A vapor cloud developed above the spill, propagated towards the ignition source and ignited. They observed that the flame propagated in two modes in the vapor cloud, as a pre-mixed flame in regions where air and fuel were mixed within the flammability limits, and as a diffusion flame in fuel-rich regions. The diffusion flame propagated back to the spill point, whereupon a pool fire resulted. Thus, pre-mixed and diffusion modes of burning can occur. The implication of this deals with the potential occurrence of explosion in pre-mixed regions, given potential breach conditions and ignition sources.

5.4 LNG Plume Modeling

The LNG plume (vapor cloud) calculations contained in the *Quest* and *Vallejo* studies are performed with standard, simplified plume models (SLAB, which is employed in CANARY and DEGADIS). These models are appropriate for dense gas dispersion such as would occur initially after an LNG spill, as discussed in the report and as supported by Lazaro et al [Lazaro et al. 1997]. The parameters used in the calculations (wind speed and stability class) are consistent with the weather data obtained. Note that these simplified plume models neglect important phenomena that might be significant.

The first phenomenon of concern is the plume itself. The plume changes characteristics during its evolution, so designation as a dense gas plume or a Gaussian plume (non-dense gas) changes with time. The initial release of the cold vapor qualifies the plume as a dense gas, because the density is significantly greater than the ambient air.

Second, the topography of the area is not considered. Due to the surrounding topography, the initially heavy gas plume will tend to be channeled along surrounding low areas, potentially decreasing the spread of the plume and increasing the plume concentration. Dependent upon the wind direction, the plume could either be directed towards populated regions or out over the water. If the predominant wind direction at a site is toward more populated regions and will initially be confined by surrounding terrain, more severe conditions might exist.

The third point is the influence of the ship and the surrounding structures on the plume behavior. Depending upon the wind direction and the location of the breach, the effect of the ship might significantly decrease the plume concentrations near the ship, due to increased mixing from turbulent eddies.

All of the phenomena of concern (topography, plume characteristics, influence of ship) can be addressed through the use of validated CFD codes such as FEM3A. FEM3A has been specifically developed to deal with LNG releases by the Gas Technology Institute and is specified in 49 CFR 193 as a model to include topographical or obstacle (ship) effects [Havens and Spicer 2002]. The use of FEM3A in predicting LNG vapor dispersion is illustrated by Chan [Chan 1992].

To assess LNG plume behavior at different times of the year for different wind conditions, it is recommended that CFD calculations using FEM3A (or its more recent version, FEM3C) or an equivalent be performed in the future using appropriate topography and hypothetical ship location scenarios. These simulations will allow for a much more mechanistic determination of the plume characteristics and the influence of the various phenomena discussed above.

5.5 LNG Spill Overpressure Considerations

The *Lehr, Fay, Quest, and Vallejo* studies did not address the possibility of overpressure and resultant damage, either from ignition on the ship or over open water. The LNG-Air explosion information discussed in Section 3 addresses these issues and concerns. Evaluation of the possibilities of events that could lead to this type of impact is discussed in Appendix D and should be considered on a site-specific basis.

6 RECOMMENDATIONS BASED ON REVIEW OF THE FOUR STUDIES

Each of the studies reviewed contains gaps and limitations in analyzing the risks and consequences of a major LNG spill over water. Several potential actions should be considered:

- Risks of potential large-scale, open-water LNG spills should be studied using modern risk analysis and risk assessment methods and techniques.
- More detailed and sophisticated LNG tanker modeling coupled with experimental validation should be undertaken, especially with respect to breach/ship interactions, ignition of escaping natural gas, LNG dispersion, and potential human and structural impacts and damage.
- These analyses should be supported by validation at the appropriate scale with the latest experimental data.
- Improvements in risk management and prevention and mitigation strategies and technologies should be evaluated to help identify the most cost effective approaches for reducing the probability, consequences, and risks to public safety and property of a large-scale LNG spill over water.

Following these efforts, guidelines for defining improved assumptions and improved approaches for simplified risk and consequence analyses could be developed, in collaboration with national and international experts, for adoption nationwide, similar to approaches already developed for locating land-based LNG storage facilities. This would help ensure that accurate and consistent approaches are used to calculate the site-specific hazards and reduce the risks of a potential large LNG spill over water.

APPENDIX B
THREAT ANALYSIS AND SPILL PROBABILITY

1 INTRODUCTION

High consequence operations such as the transportation of LNG imply potential risks to people, facilities, and equipment. Effectively evaluating the risks of a large LNG spill over water requires that the potential consequences be considered in conjunction with the probability of an LNG cargo tank breach and spill, along with the range of physical or operational measures that can be employed to prevent or reduce the hazards and risks of a potential spill. Appendix B discusses the modeling and analysis conducted of the probability and likelihood of an LNG cargo tank breach from a range of threats and the associated size of the breach.

2 ASSUMPTIONS, MODELS, AND THREAT ANALYSIS

The breach of an LNG carrier can include both accidental and intentional scenarios. While potential accidents are commonly considered in the development of safety equipment and systems, operational directives, and risk management and emergency response plans, intentional acts such as sabotage, intentional grounding, or even physical attacks in the past have often not been considered. However, under existing international situations, intentional attacks and the security and protection of critical infrastructures and systems must be considered.

For this study, a wide range of potential accidental and intentional breachings of LNG cargo tank scenarios were evaluated. Scenarios considered were based on discussions with intelligence agencies and a review of emerging hostile activities around the world [Krane 2000]. This historical information was used to develop credible threat scenarios. For these scenarios, modeling and analysis tools were used to establish a range of expected or likely breaches of an LNG cargo tank and the results presented in Table 36 below.

2.1 Accidental Breaching Evaluations

As noted in Section 2 of this report, the LNG industry has an exemplary safety record with only eight marine accidents over the past 40 years in which LNG was spilled, but without resultant fires. None of these accidents led to a loss of life. Even with this excellent safety record, consideration should be given to what might be a likely LNG cargo tank breach based on a potential accidental collision with another ship, grounding, or ramming. The severity of a breach based on these events depends on the location, vessel design, relative vessel speeds and collision alignment, and mitigation or prevention systems in place to limit potential damage.

Sandia had previously conducted sophisticated finite element modeling of collisions of a series of ships with a double-hulled oil tanker similar in overall size, mass, and design to an LNG vessel. A summary of the analysis of a 90-degree collision of a large container ship (50,000 metric ton class ship) and a double-hull tanker (80,000 metric ton class) is shown in Figure 7 and collisions with smaller ships are shown in Figure 8 [Ammerman 2002]. The analysis tool included an approximately 250,000 finite element model of both the impacting vessel and the double-hulled tanker using PRONTO-3D run on a massively parallel computer with 256 processors. This is a transient dynamic, explicitly integrated, Lagrangian solver of the equations of motion. The analysis tracked the progressive failure of the struck ship as the striking ship penetrated. As noted in these figures, breaching of the inner hull does not occur until impact velocities exceed approximately 5 – 6 knots for large vessels. For small vessels, such as pleasure craft, kinetic energy is approximately one to two million N·m. Figure 8 shows that this level of kinetic energy is generally insufficient to penetrate the inner hull of a double-hulled vessel such as an LNG ship.

This analysis also calculated that penetration into a double-hulled tanker must be approximately three meters before a hole occurs in the inner hull. This, therefore, can be used to estimate the minimum size of a penetration to cause a penetration and spill in a grounding event. Because of the design of LNG ships, the penetration could be even greater in many cases. The results for this analysis were compared with initial collision information from the recent Baltic Carrier collision at approximately 12 knots. The results of these analyses over-predict, by about 15%, the external hole size measured for that collision

Based on these analyses, several observations can be made. First, LNG vessels, because of their additional insulation and third level of containment, would require deeper penetrations to rupture the primary LNG cargo tank. Therefore, because of its general design and construction, collision velocities for equivalent hole sizes could be expected to be 1-2 knots higher for an LNG vessel. This would suggest the required velocity to cause a breach of an LNG cargo tank during a 90 deg collision with a large vessel to be 6-7 knots. Collisions at shallower angles would need to be several knots higher in order to penetrate an LNG cargo tank. Referring to Figure 7, collisions with larger vessels than those considered in the analysis could cause slightly larger holes, which should be considered in developing accident prevention strategies

An additional element to consider in the accident scenario is that the hole size developed probably is not the size of the spill orifice. In many collisions between two ships, the ships can remain joined for several hours if significant penetration of one ship occurs. The analysis by Ammerman suggests that as little as 5 – 10% of the generated breach size would be available for the release of LNG. Therefore, the collision of a large ship with an LNG carrier at even 12knots is expected to produce an effective hole area of no more than approximately one square meter for an LNG spill. If larger spills do occur, hole sizes could approach those calculated for intentional breaches.

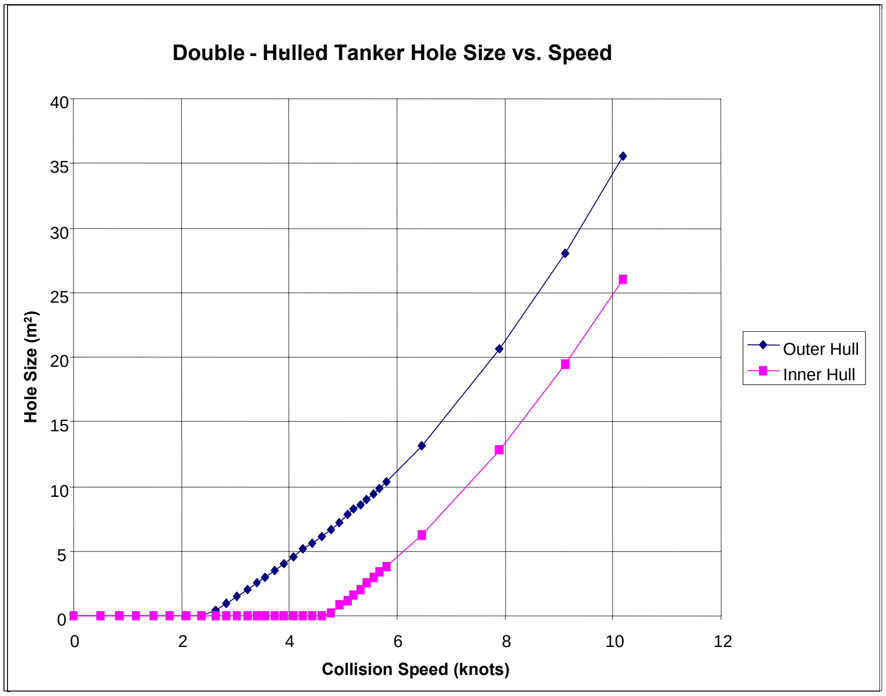


Figure 7. Study Estimate of Speed Required to Create a Given Hole Size

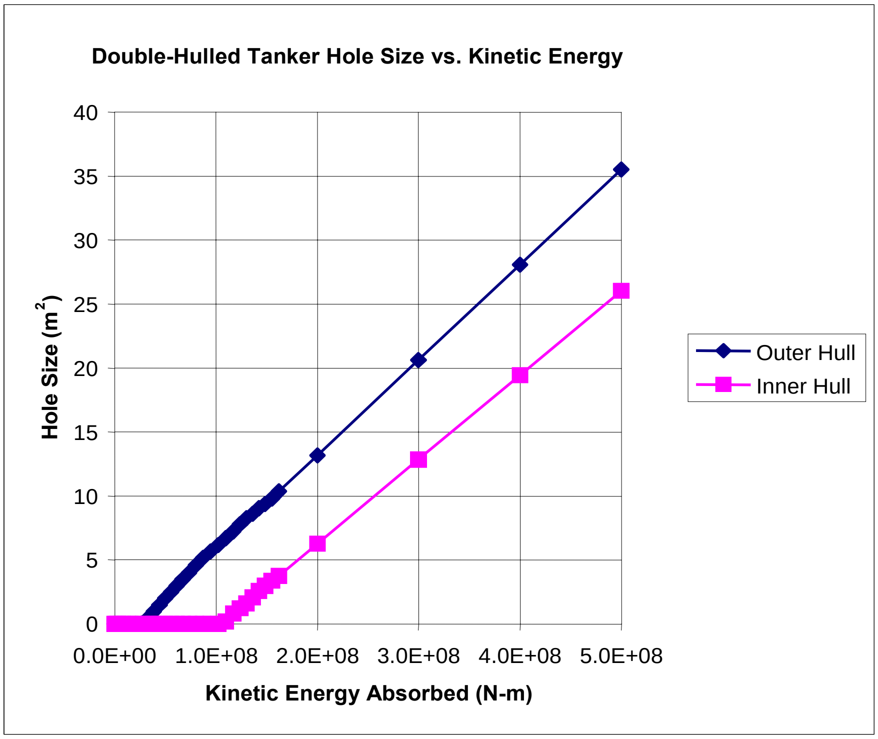


Figure 8. Double-Hull Tanker Study of Energy Required to Create a Given Hole Size

2.2 Intentional Breaching Evaluations

The breach of an LNG cargo tank from an intentional act should include evaluation of a range of threats, including sabotage, insider threats, and external attacks. A wide range of attacks against ships has been documented, including hijackings, attacks with small missiles and rockets, and attacks with bulk explosives [Krane 2000]. While this range of threats must be considered when assessing the vulnerability and consequences of an intentional attempt to breach an LNG vessel, the actual threats and consequences are sensitive.

While a discussion of the specific threats and expected consequences is inappropriate for this report, it is appropriate to discuss the range of breaches that were calculated for a wide range of intentional events. A summary of the modeling and analysis efforts developed and conducted to calculate the potential breaches from various intentional scenarios is presented in an associated classified report [Hightower 2004].

Many reports currently published postulate a potential hole size of as much as 20 – 25m^2 from a major accident or intentional breach. A computational shock physics code, CTH, and material data were used to calculate expected breach sizes for several different intentional scenarios. CTH is Eulerian finite volume code and is required to estimate and analyze the large-scale deformations and material responses under very high strain rates that a developed due to high velocity penetration or explosion scenarios.

Several different intentional breaching scenarios were evaluated. They ranged from sabotage and hijacking to other types of physical attacks. The intentional scenarios evaluated included those events deemed credible from intelligence and historical data. A credible event means that a group (or groups) could have the general means and technical skill to accomplish successfully an intentional breach.

Based on the analyses for both LNG tanker designs, the range of hole sizes calculated from an intentional breach of an LNG cargo tank is between 2 – 12 m^2. Our analysis suggests that, in most cases, an intentional breaching scenario would not cause a tank breach of more than 5 – 7 m^2. This is a more appropriate value to use in calculating potential hazards from spills. As shown in Table 36, it is possible to create a breach in more than one LNG cargo tank under certain intentional scenarios. In addition, in some intentional scenarios, a breach might be such that spilled LNG could stay substantially if not totally within the ship ballast and double hull spaces.

3 LNG BREACH SUMMARY

Based on the breach scenarios identified and evaluated, realistic hole sizes of between 2 – 12 m^2 appear possible. The general sizes are shown in Table 32 for both accidental and intentional breaches. For both LNG tanker designs, a breach could occur in the LNG cargo tanks either above or below the water line. This will impact the amount of LNG spilled onto the water surface and the amount of LNG that might be spilled into the internal ballast areas between the hulls, vacant hold areas, etc.

As shown conceptually in Figure 5, based on the evaluation of the available void space between the hulls, in some cases almost all of the LNG spilled in a breach might be captured within the LNG vessel. While this will reduce the volume of LNG spilled onto the water and the potential spill surface size, it could negatively impact the structural integrity of the LNG vessel. This has been evaluated and is discussed in Appendix D.

Table 32: Estimated LNG Cargo Tank Breach Sizes for Various Scenarios

BREACH EVENT	BREACH SIZE	CARGO TANKS BREACHED
Accidental Collision with Small Vessel	none	none
Accidental Collision with Large Vessel, (90° @ 7 knots)	none	none
Accidental Collision with Large Vessel, (90° @ 12knots)	5-12m^2 (effective breach: 0.5 – 1m^2)	1
Accidental Grounding	none	none
Intentional Breach	0.5 m^2	1
Intentional Breach	2 m^2	3
Intentional Breach	2-12m^2	1
Intentional Breach	5 m^2	2
Intentional Spill	Premature offloading of LNG	none

The risk of a breach of an LNG cargo tank due to an accident, such as a collision or grounding, appears to be minimal. The risk of such a breach can be easily reduced through a number of operational mechanisms that includes managing ship traffic, coordinating ship speeds, and by active ship control in inner and outer harbors where the consequences of a potential LNG spill might be most severe. The Coast Guard currently uses all these methods. The safety and hazard issues from an accidental breach appear manageable and adequate with current safety policies and practices based on the safety records of LNG vessels in port.

The intentional breaches shown above in Table 32 cover several events, including a range of possible attacks and insider threats. The large hole sizes calculated, while smaller than commonly assumed in many studies, still provide the potential for large LNG spills and need to be looked at closely. A wide range of operational strategies, though, might be available to prevent or mitigate many of the identified intentional breach scenarios.

APPENDIX C
LNG SPILL AND DISPERSION ANALYSIS

1 INTRODUCTION

This appendix provides an in-depth literature review of experimental and technical studies associated with the dispersion and potential thermal hazards of an LNG spill from either an accidental or intentional event. A broad range of potential modeling and analysis issues associated with spills and potential thermal hazards is identified and discussed.

Table 33 provides an overview of existing LNG spill testing data.

Table 33: Largest Spill Volumes Tested to Date Giving Pool Radius and/or Distance to LFL

EXPERIMENT	SPILL SIZE (m^3)	SPILL RATE (m^3/min)	POOL RADIUS (m)	DOWNWIND DISTANCE TO LFL (m) (Max)
ESSO	0.8 – 10.8	9 – 17.5	7 – 14	400
U.S.CC	3 – 5.5	1.2 – 6.6	~ 7.5	Not measured
Maplin Sands (dispersion tests)	5 – 20	1.5 – 4	~ 10	190 ± 20 m
Maplin Sands (combustion tests)	10.35	4.7	~15	Not measured
Avocet (LLNL)	4.2 – 4.52	4	6.82 – 7.22	220
Burro (LLNL)	24 – 39	11.3 – 18.4	~5	420
Coyote (LLNL)	8 – 2 8	14 – 19	Not reported	310
Falcon (LLNL)	20.6 – 66.4	8.7 – 30.3	Not reported	380

2 LIQUID POOL

2.1 Spreading

2.1.1 Experiments

The experiments summarized in the table below, measuring dispersion only, provide information on pool radius. Thus, mass fluxes are due to the heat transfer from water contact and not from fire.

Table 34: Largest Spill Volumes Tested to Date Giving Pool Radius and Max. Flux Rate

EXPERIMENT	VOLUME SPILLED (m^3)	POOL RADIUS (m)	MASS FLUX (kg/m^2 s)
Boyle and Kneebone (Shell)	0.02 – .085 Quiescent water surface (laboratory)	1.97 – 3.63	0.024 – 0.195 Increased with amount spilled & amount of heavy hydrocarbons.
Burgess et al.	0.0055 – 0.36 (pond)	0.75 – 6.06	0.181
Feldbauer et al. (ESSO)	.8 – 10.8 (Matagorda Bay)	7 – 14	0.195
Maplin Sands	5 – 20 (300 m dyke around inlet)	~10	0.085
Koopman et al. (Avocet LLNL)	4.2 – 4.52 (pond)	6.82 – 7.22	Not reported

2.1.2 Models

Several models have been developed for the spread of LNG on water [Otterman 1975] [Georgakis et al. 1979] [Briscoe and Shaw 1980] [Raj and Kalelkar 1974] [Fay 1973] [Hoult 1972] [Might and Perumal 1974]. Otterman and Briscoe provide model-to-model comparisons for spills on the order of 103 – 104 m^3. The majority of models assume that spreading is driven only by gravity, and ignore the action of waves and currents, preferential boiling, and pool break-up.

The following models are typical approaches used to model the spread of LNG on water. These models are being described because they have been compared to experiments and they account for the heat flux to the LNG from water.

Opschoor developed a model for the spread and evaporation of LNG on open and confined quiescent water surfaces [Opschoor 1980]. For unconfined water surfaces, the model assumes that boiling occurs in the film-boiling mode and that no ice formation occurs. For confined water surfaces, the model assumes that, during the spreading phase, no ice formation occurs due to film boiling and that, after spreading, an ice layer forms due to a decrease in the temperature difference between LNG and water such that film boiling cannot be maintained, resulting in contact between the LNG and water. The results were compared with experiments by Shell for spills of 38kg (.09 m3) [Boyler and Kneebone 1973]. There was agreement with evaporation rate for confined water surfaces for the ice formation period, and fair agreement for confined water surfaces for pool radius. When compared to experiments by the U.S. Bureau of Mines (163 kg), the model under-predicts the pool radius over time [Burgess et al. 1970].

Waite incorporates heat transfer, preferential boil-off of methane (90%) and ethane (10%), and gravity spreading of the pool [Waite et al. 1983]. The model was compared to experiments conducted by U.S. Bureau of Mines [Burgess et al. 1970] and Shell [Fay 1973], which had spills of 163 kg (0.36 m^3) and 38 kg (.09 m^3), respectively. Assuming a heat flux typical for film boiling (~25 kW/m^2), the model had fair agreement, within 20%, on the pool radius found in these experiments. This heat flux value gave better agreement than the heat flux typically assumed of 100 kW/m^2. No ice formation occurred for unconfined spills.

Brandeis and Ermak developed a numerical model based on the depth-averaged, shallow water equations [Brandeis and Ermak 1983]. Instantaneous and continuous spills that included the effect of mass and heat transfer, shear forces, and surface tension were modeled. Pool break-up was accounted for by including the effect of shear forces and surface tension. It was found that the time necessary to reach a steady-state radius for continuous spills increased as surface shear stress increased. The steady-state pool radius was not affected. The results were compared to experiments performed by Boyle and Kneebone on a 0.0817 m^3 spill, and indicated good agreement.

Cavanaugh developed a code (LSM90) that simulates multi-component spills on land or water that accounts for flashing liquid, entrainment as aerosol, liquid pool evaporation, and heat and mass transfer effects [Cavanaugh et al. 1994]. Spreading is driven by gravity and the actions of waves are not modeled. Results were compared to the Esso [Feldbaur et al. 1972] and Burro [Koopman 1982] series of experiments. The difference between experimental and computed results for evaporation rate varied from 1 – 48%, with eight out of ten cases within 14%. The average difference for pool size comparison was 12%. The spill size for which the comparison was made was not stated.

2.2 Pool Boiling

2.2.1 Experiments

Boe performed laboratory scale experiments with liquefied methane-ethane and methane-propane mixtures boiling on water [Boe 1998]. The results indicated that addition of ethane or propane affects the boil-off rate. High initial boil-off rates were observed for methane rich mixtures similar to that of typical LNG compositions. The boil-off rates increased by a factor of 1.5 – 2 from that of pure methane, when either ethane or propane was added to methane to obtain a 97% methane mixture. It was concluded that there is a breakdown of film boiling due to closer contact between the mixture and water, causing a higher heat flux and lower surface temperature below that to maintain a continuous vapor film.

Results by Drake on laboratory scale experiments showed that LNG had a higher boiling rate than pure methane on a bound-free surface [Drake et al. 1975]. The rate of boiling increased with time and foaming of the LNG occurred on the water surface. These results agree with Valencia-Chavez and Reid on laboratory scale confined spills [Valencia-Chavez and Reid 1979].

2.2.2 Models

Conrado and Vesovic developed a model to investigate the influence of chemical composition on the spill behavior of LNG and LPG for unconfined water surfaces [Conrado and Vesovic 2000]. Spreading based upon a gravitational-inertia balance, heat transfer, and vaporization was included in the model. They point out that preferential evaporation occurs and that boiling does not take place at a constant temperature. They found that a decrease in the rate of vaporization, due to the change in composition of the pool, occurs in the later stages of the pool. The vaporization rate for LNG versus methane was found to be different. By not considering preferential boil-off, this would result in underestimating the evaporation time by about 20%. For instantaneous spills, results indicate that neglecting evaporation while spreading is a reasonable assumption. They conclude that models should use the properties of LNG as opposed to those of pure methane.

2.3 Rapid Phase Transition (RPT) Explosions

2.3.1 Experiments

Coyote Tests - 1981 [Goldwire et al. 1983] [McRae et al. 1984] [Morgan et al. 1984] [Rodean et al. 1984] [Ermak et al. 1983] [Ermak et al. 1982]

The Coyote series is a continuation of the Burro test series to further study combustion hazards and rapid phase transition (RPT) explosions. They were performed by Lawrence Livermore National Laboratory (LLNL) and the Naval Weapons Center at China Lake, California, and sponsored by the U.S. DOE and the Gas Research Institute. To study RPTs, 13 spills of 3 – 14 m^3 with flow rates of 6 – 19 m^3/min were performed with fuel of varying ratios of methane, propane, and ethane. Five spills of 8 – 28 m^3 with flow rates of 14 – 17 m^3/min were also performed, obtaining dispersion and combustion data under a variety of meteorological conditions.

Six of the 18 Coyote spills produced RPT explosions. Most were early RPTs that occurred immediately with the spill, and in some cases continued for the duration (over a minute) of the spill. They were generally located near the spill point and appeared to be primarily underwater. Delayed RPTs, occurring at the end of the spill and located away from the spill point out on the LNG pool surface, were also observed. Delayed RPTs occurred on three tests.

The results indicate that, for the spill sizes tested, the pre-spill composition is not a good indication of the likelihood of an RPT. Enger and Hartman from Shell performed a series of small-scale experiments (~0.1 m^3) and found that there is a composition envelope within which RPTs can occur [Enger and Hartman 1972]. The Coyote tests found RPTs occurring outside this envelope, indicating that other mechanisms become dominant for larger spills.

Water temperature appeared be correlated with the occurrence of RPTs. RPTs occurred with the water temperature above 17°C, except for one test in which the water was 11.6°C and the adjustable spill plate was removed, indicating that the depth of penetration might affect the occurrence of RPTs as well. The strength of RPTs was found not to correlate with impact pressure. This is in contrast to what was found for laboratory-scale spills by Jazayeri, in which cryogens were impacted with water and a correlation was found between RPT strength and impact pressure [Jazayeri 1975].

Spill rate was found to correlate with maximum RPT yield. An abrupt increase in the RPT explosive yield was found at around 15 m^3/min, from which the strength increased by five orders of magnitude, to 18 m^3/min. The maximum equivalent free-air, point source TNT explosion that occurred was 6.3 kg for about an 18 m^3/min spill rate.

2.3.2 Models

Vapor explosions have been extensively studied in the nuclear power industry and in the industrial process industry, such as foundries. Research on LNG/water explosions has been principally at laboratory scale [Khalil et al. 1988] [Anderson and Armstrong 1972] [Katz and Sliepcevich 1973]. Several theoretical models have been proposed to explain the formation of RPTs, though none has addressed the large-scale behavior observed in the Coyote experiments. There are several recent reviews of the various theories proposed to explain steam explosions [Berthoud 2000] [Schubach 1996] [Fletcher and Theofanous 1994].

The prevalent theory is the superheat theory, which proposes that film boiling occurs immediately after LNG is spilled on water. Then, due to possible instabilities and a decrease in the temperature difference, the film boiling vapor layer collapses in localized areas, resulting in liquid/liquid contact. This direct contact results in rapid vaporization from the increased heat transfer so that a pressure wave is produced to achieve an explosion. For an explosion to occur, the water must be equal to, or slightly greater than, the superheat temperature of LNG ($\mathbf{T}_{superheat} < \mathbf{T}_{water} < \mathbf{1.1}\ T_{superheat}$). Superheat temperature for methane, ethane, propane, and butane are 168, 269, 326, and 376°K, respectively [Khalil et al. 1988]. The superheat temperature of hydrocarbon mixtures is approximately the mole fraction average of the superheat temperatures of the components [Porteous and Blander 1975].

It has been shown that much different behavior occurs at larger scales, which is not predicted from smaller scale studies. For instance, Enger et al. concluded from laboratory scale experiments that the methane content of LNG must be less than the 40 mole % for RPT explosions to occur; but this was found not to be the case for the much larger spills in the Coyote tests, as previously discussed. It has been shown for both laboratory scale and larger field tests that composition, as well as water temperature, is a factor in the occurrence of rapid phase transitions.

Napier and Roochland raise the issue of rapid phase transitions causing ignition by either electrostatic discharge or frictional sparks created near the explosion, or by shock heating of the methane-air mixture [Napier and Roochland 1984]. Based on using shock tube analysis, they concluded that shock heating of unconfined flammable mixtures of methane to the auto ignition temperature (813°K) is not possible. The experimentally determined temperature available is 450°K; the theoretical is 500°K. They state that ignition is possible via an electrostatic discharge or frictional sparks; but that these ignition modes are difficult to quantify. The ignition source would have to be located on the boundary of the RPT, where the fuel concentration is between the flammability limits.

3 DISPERSION

3.1 Experiments

The following describes experiments on the dispersion characteristics of vapor clouds formed from LNG spills onto water. Only the largest spill volume tests have been reviewed and discussed. Smaller spill volume tests have been performed and are listed in the recent review on cryogenic spills by Thyer [Thyer 2003].

Shell Jettison Tests – 1973 [Kneebone and Prew 1974]

Shell performed a series of six tests in which LNG was jettisoned from the 'Gadila,' a 75,000 m^3 capacity ship. The primary objectives of the tests were to determine the feasibility of emergency jettison of fuel with high discharge rates while the ship is stationary, as well as low discharge rates while the ship is moving. The flow rates tested ranged from 2.7 to 19.3 m^3/min, lasting a total of ten minutes, and producing total volumes spilled that ranged from 27 to 193 m^3. Four tests were performed while the ship was moving from 3 to 10.5 knots, and two stationary tests were performed, one of which was with the highest volume spilled. The methane, ethane, and propane content by mole percent were 87.11%, 9.05%, and 2.75%, respectively. Two different jet nozzle sizes were used (51 and 102 mm) located 18 m above the water. The relative humidity was between 80 and 85%, and wind speed ranged from 1.9 to 5.1 m/s.

Measurements were taken of the following: ship speed, wind speed and direction, air and seawater temperature, distance of liquid and vapor cloud from the ship, and electrostatic field strength in the jet exiting the nozzle. Concentration measurements were not taken. Infrared camera results indicated that, with the 51 mm nozzle, LNG pools on the sea surface did not form and only isolated patches formed for the 102 mm nozzle. This could be due to the LNG evaporating before it reached the sea surface, because it was released from an elevated horizontal jet. Thus, ice formation or RPT explosions were not observed. It was visually observed that the clouds completely dispersed within 15 – 20 minutes after the discharge was completed for the 102 mm nozzle at a discharge rate of 19.3 m^3/min.

For the highest volume spilled, 193 m^3 (3.9 m/s wind), the visible plume appeared to be uniform over its entire length and had a height of 10 – 12 m, maximum continuous width of 550 m, and length of 2250 m. The length was observed continuing to increase after the test.

Maplin Sands Tests – 1980 [Puttock and Blackmore 1982] [Blackmore and Summers 1982] [Blackmore et al. 1982] [Colenbrander and Puttock 1983]

Tests were conducted at Maplin Sands, England by the National Maritime Institute and were sponsored by Shell. These tests were performed to obtain dispersion and thermal radiation data on 20 spills of LNG and 14 spills of propane onto water. The spill point was surrounded by a 300 m diameter dyke to retain the tide. For instantaneous spills, the spill volumes tested were 5-20 m^3, and for continuous spills, the spill rates tested were 1.5-4 m^3/min. Tests were performed for average wind speeds of 3.8-8.1 m/s.

Results indicate that the LFL is reached within the visible boundary of the vapor cloud for the humidity range of 50-100%. A rapid phase transition (RPT) was observed in one of the instantaneous LNG spills. The maximum overpressure was 18 mbar and damage to the barge used to carry out the instantaneous spill occurred.

The dispersion behavior of the cloud was affected by the method of LNG release. For an underwater release, a more buoyant cloud resulted, whereas with an above water release, a lower and longer downwind cloud resulted. A typical pool radius was roughly 10 m, and the evaporation rate was calculated to be approximately 2×10^{-4} m/s (0.085 kg/m^2s). Using a 3-second average measurement, the maximum dispersion distance to LFL for a spill rate of 3.2 m^3/min and wind speed of 5.5 m/s was 190±20m downwind of the spill.

Burro Tests – 1980 [Koopman et al. 1982, a&b] [Koopman et al. 1978]

The Burro tests were performed by LLNL and the Naval Weapons Center at China Lake, California, and sponsored by the U.S. DOE and the Gas Research Institute. A total of eight LNG releases onto water were performed, with spill volumes ranging from 24 to 39 m^3, spill rates of 11.3 – 18.4 m^3/min, wind speeds from 1.8 to 9.1 m/s, and atmospheric stability conditions from unstable to slightly stable. Dispersion occurred over water for 29 m from the spill source on a pond, then over land for 80 m, where the terrain was irregular with a rise of 7 m. Beyond this point, the land was relatively level.

These tests were preceded by the Avocet series of discovery experiments for 5 m^3 spills [Koopman et al. 1978]. The Avocet tests were performed in order to gain insight into the measurements necessary for the larger spills to be tested in the Burro series of experiments. It was concluded that a large array of instruments would be necessary for larger tests and that wind speed variations have a significant effect on liquid spread and the boil-off rate of the pool.

Measurements of wind speed and direction, gas concentration, temperature, humidity, and heat flux from the ground were made at various distances from the spill and at various elevations. Gas measurements were averaged over a 10-second duration. High-frequency data indicated that significant fluctuations about the 10-second-average occurred such that the flammable extent of the gas cloud will be larger than is indicated by the mean LFL contour.

In one of the tests, the cloud caused displacement of the atmospheric flow and resulted in the wind speed decreasing to almost zero within the cloud. The dense cloud was able to dampen turbulent mixing by stable stratification and, thus, the wind was able to flow over the cloud as if it were a solid object. This test was performed under a low wind speed of 1.8 m/s, slightly stable atmosphere, and spill rate of 16 m^3/min (28.4 m^3). For the other tests with higher wind speeds, this effect was not observed. The cloud was wider and lower in height than that of any other test. The maximum radial distance to LFL at 1 m elevation was approximately 420 m. The cloud also remained over the spill region after the spill ended, in contrast to the other tests, in which the cloud propagated downwind within 10 – 20 seconds after spill termination.

Differential boil-off was observed in the tests where ethane and propane enrichment up to 40% in the cloud occurred late in the spills and propagated downwind up to 140 m. It was also found that a relative increase in absolute humidity is correlated to an increase in gas concentration.

RPT explosions with a maximum overpressure (static) of .72 psi were measured 30 m from the RPT itself. The explosions were strong enough to cause damage to the facility.

<u>Falcon Tests – 1987</u> [Wiersma and Williams 1989]

The Falcon tests were conducted at Frenchman Flat in Nevada by LLNL and sponsored by the Gas Research Institute and the U.S. DOT. The objectives of the tests were to provide a database on LNG vapor dispersion from spills involving obstacles and to assess the effectiveness of vapor fences for mitigating dispersion hazards. The testing was performed on a 40 x 60 m pond, enclosed by an 88 m long by 44 m wide by 9.1 m high vapor fence. A 22 m wide by 13.7 m high barrier was erected upwind of the pond, in order to simulate the obstruction of a storage tank.

Five tests were performed with spill rates of 8.7 – 30.3 m^3/min (20.6 – 66.4 m^3), wind speeds of 1.7 – 5.3 m/s, and methane concentrations of 88 – 94.7%. Gas concentration and temperature measurements were taken at towers both upwind and downwind of the spill

The test with the highest volume, 66.4 m^3 (spill rate 28.7 m^3/min), and most stable atmospheric conditions (Falcon 1) resulted in the vapor cloud overfilling the vapor fence on all four sides. Pre-spill wind tunnel simulations predicted that the cloud would stay within the fence. It was speculated that this was due to enhanced, turbulent mixing from the high spill rate and partly due to superheating of the LNG from the water beneath. This could not be substantiated, due to insufficient measurements of concentration and temperature in the source area. A maximum downwind distance to LFL of 330 m was measured for this case.

Tests were performed with and without the vapor fence. With the fence in place, the downwind distance to the 2.5% concentration on the ground was reduced from approximately 380 m to 235 m and a substantial reduction in the hazardous areas was achieved. The persistence of the cloud at a 2.5% concentration near the center of the spill was 530 s with the fence versus 330 s without the fence. Although the fence reduced the downwind distance of the hazardous area and delayed cloud arrival time, it prolonged the cloud persistence time within the fence, thereby prolonging the potential for ignition.

Large RPT explosions occurred approximately 60 sec. after the spill; and a fireball started inside the vapor fence at 81 sec. for Falcon 5, which had a spill rate of 30.3 m^3/min, total volume of 43.9 m^3, and methane content of 88%. Only limited data outside the fence was obtained up to about 100 sec. Rapid phase transitions also occurred with Falcon 3, with a spill rate of 18.9 m^3/min, total volume of 50.7 m^3, and methane content of 91%.

3.1.1 Models

Dense gas dispersion models generally fall into the following categories: Navier-Stokes based, Lagrangian nonlinear puff, shallow layer or two-dimensional integral, one-dimensional integral, and simplified empirical. The following will describe these models and discuss various codes representative of these model types.

Navier-Stokes Based Models

The most complex models are those based on Navier-Stokes. These models computationally solve time-averaged, three-dimensional, turbulent transport equations that come from conservation of mass, species, momentum, and energy balances. Usually, turbulent transport is modeled using a first order, eddy diffusivity approximation, in which eddy diffusion tensors are specified by ad-hoc equations. The most well known code of this is FEM3 [Chan 1992] [Chan et al. 1984] [Chan et al. 1987] [Leone et al. 1985] [Ermak 1982] and its subsequent upgraded versions, up to FEM3C [Chan 1994] [Chan 1997].

Developed by Lawrence Livermore National Laboratory, FEM3 uses a Galerkin finite element scheme in space and a finite difference scheme in time. The latest version (FEM3C) flows over variable terrain and objects, as well as complex cloud structures, such as vortices and bifurcation. Both isothermal and non-isothermal dense gas releases, as well as neutrally buoyant vapor emissions, can be modeled. FEM3C can model multiple simultaneous sources of instantaneous, continuous, and finite-duration releases. FEM3C also incorporates a phase change model that accounts for water vapor interaction in the cloud; and it has the option to use the k-epsilon turbulent transport equations, which is a second order turbulence model.

Limitations of these codes are in the approximations and assumptions that are used to model turbulence and buoyancy effects. They are the most computationally expensive among the model types, but with increasing computing power, this is not as problematic as it was ten years ago or more.

Lagrangian Nonlinear Puff Models

Gaussian puff models are typically for buoyant or neutrally buoyant releases, such as from an elevated stack source. Recently, the code called SCIPUFF (Second-order Closure Integrated Puff), developed by Titan Research and Technology, includes a dense gas release model [Sykes et al. 1999]. SCIPUFF uses a Lagrangian puff dispersion model that captures nonlinear interaction among a collection of Gaussian puffs to represent a three-dimensional, time-dependent concentration field. Dense gas effects are captured by using the conservation of vorticity moment equation. Turbulent diffusion is based on a second-order closure model. Finite duration, unsteady, and multiple sources can be modeled, as well as flow over flat or complex terrain. Comparisons to dense gas field data on maximum concentration over all sampling locations at a given distance and over the sampling period from Maplin, Burro, and Coyote tests show the model predicting concentration values within a factor of two.

Shallow-Layer Models

Shallow-layer models use equations that assume the lateral dimensions are much greater than the vertical dimension, which is representative of dense gas releases where low wide clouds result. One such model, TWODEE, has been developed for dense gas releases by Hankin and Britter [Hankin 2003] [Hankin and Britter 1999]. Depth-averaged variables are solved in two dimensions (lateral) using the conservation equations. Empirical correlations are used to determine the entrainment rate. The ability to model the effects of complex terrain and phase changes can be incorporated into this model. It is a compromise between Navier-Stokes based models and one-dimensional integral models, though it still requires an order of magnitude greater computational time than one-dimensional integral models.

One-Dimensional Integral Models

One-dimensional integral models such as SLAB [Ermak 1980], HEGADAS [Colenbrander and Puttock 1983] and DEGADIS [Spicer and Havens 1989] use similarity profiles that assume a specific shape for the crosswind profile of concentration and other properties. The downwind variation of spatially averaged crosswind values is determined by using the conservation equations in the downwind direction only. These models include eddy diffusivity models for turbulent transport. The weakness of these models is that they cannot capture flow around obstacles or over complex terrain. The DEGADIS and SLAB models are used widely in the both public and private sectors. In addition to jet releases, both can model buoyancy-dominated, stably stratified, or neutral releases. There are some models of this type, such as GASTAR, developed by Cambridge Environmental Research Consultants (CERC), that incorporate the effect of terrain, such as variable slopes and ground roughness and obstacles, including porous, into the integral formulation.

Empirical Models

The simplest models are modified Gaussian puff/plume models that are principally based upon the conservation of species equation. The downwind concentration profiles are represented by ad hoc equations. The cloud is assumed to have a specific shape with air entrainment occurring at the cloud edges and the interior of the cloud is assumed to have a uniform composition. Empirical models by Germeles and Drake, Fay and Lewis, Burgess et al. Feldbauer et al., SAI, U.S. Federal Power Commission, and U.S. Coast Guard are compared by Havens [Havens 1981].

3.1.2 Model Evaluation Studies

Fifteen integral models, including publicly available and proprietary, were evaluated in a validation exercise by Hanna, et al., in which calculations were compared to data from eight field experiments that included the Maplin Sands, Burro, and Coyote test series [Hanna et al. 1993]. SLAB, HEGADAS, DEGADIS, and GASTAR were able to predict maximum plume centerline concentrations and plume width for these field tests to within a factor of two. It was noted that all of the models were unable to reproduce the variation of concentration with averaging time from field data because they assume that the cloud has a dense gas 'core' that is unaffected by averaging time.

Mercer compared several integral models against one another (and not to experimental data) by considering twenty-five cases that varied in wind speed, atmospheric stability, roughness length, spill volume, and pool radius [Mercer et al. 1994]. For each case, the density of the release was twice that of air and only instantaneous releases were considered. The models varied within a factor of three to five, and the greatest differences among them arose out of the case with low wind speed, F-stability class, and large roughness length.

An evaluation protocol of dense gas dispersion models has been developed through a program called SMEDIS, a European Union research project funded by the Environment and Climate Research Program [Daish 2000] [Carissimo et al. 2001]. Several dense gas dispersion models were assessed from their publication and are listed in Figure 9.

Table 35 shows the data sets to which the models were compared. The evaluation procedure incorporates validation, verification, and scientific assessment for simple, as well as complex, situations that include aerosols, topography, and obstacles. Screening tools, integral models, shallow-layer models and validated CFD models were compared among a dataset of field and wind tunnel data. It was found that all models were globally better at predicting arc-wise measurement, such as centerline maximum concentration, than point-wise statistical measures, suggesting that is more difficult to predict the general cloud shape.

For a particular model type, Tables 36 and 37 show the percentage of model results that were within a factor of two in the experimental results. Table 36 shows results for arc-wise comparison and Table 37 for point-wise comparison. The validated CFD models performed better overall on statistical measures of geometric variance, mean relative square error, and fraction within a factor of two. It was also noted that more information is necessary from field experiments on sensor accuracy and data uncertainty in order to define acceptable agreement with model predictions.

Table 1 The models participating in SMEDIS (HSE = Health and Safety Executiv
Health and Safety Laboratory; CUED = Cambridge University Engineering Departmer
model uses a worst-case approach and has not been included in the statistical analysis (

Model	Developer
Screening tools	
Britter-McQuaid Workbook	HSE and CUED (UK)
VDI Guideline 3783 Part 2	Meteorologisches Institute (Germany)
Integral models	
AERCLOUD	Finnish Meteorological Institute (Finland)
DEGADIS	US Coastguard, US-EPA and Gaz Research Institute (USA)
DRIFT	AEA Technology (UK)
EOLE	Gaz de France (France)
ESCAPE	Finnish Meteorological Institute (Finland)
GASTAR	CERC Ltd. (UK)
GReAT	Risø National Laboratory (Denmark)
HAGAR	BG Technology (UK)
HGSystem	Shell Research (UK)
OHRAT/Multi-stage	Det Norske Veritas (UK/Norway)
PHAST/UDM	Det Norske Veritas (UK/USA)
SLUMP	W.S. Atkins Safety and Reliability (UK)
WHAZAN/HVYCLD	Det Norske Veritas (UK/USA)
Shallow-layer models	
DISPLAY-1	EC Joint Research Centre (Italy)
DISPLAY-2	EC Joint Research Centre, Ispra (Italy)
SLAB	Lawrence Livermore National Laboratory (USA)
SLAM	Risø National Laboratory (Denmark)
TWODEE	HSE/HSL (UK)
CFD Models	
ADREA-HF	NCSR 'Demokritos' (Greece)
CFX	AEA Technology (UK)
COBRA	Mantis Numerics Ltd. (UK)
FLACS	Christian Michelsen Research (Norway)
FLUENT	FLUENT (UK)
KAMELEON FireEx 98	SINTEF (Norway)
MERCURE	Electricité de France (France)
STAR-CD	Computational Dynamics Ltd. (UK)

Figure 9. The Models Participating in the SMEDIS Database and Validation Exercise

[Carissimo, et al. 2001]

Table 35: Dataset Groups Selected Based on Questionnaires Returned by All Participants.

[Carissimo, et al. 2001]

IDENTIFIER	SCALE	MATERIAL	SOURCE TYPE	NUMBER OF TESTS	COMPLEX EFFECTS
Burro	Field	LNG	Pool	8	fast aerosol evaporation
Desert Tortoise	Field	Ammonia	Jet	4	Aerosol
FLADIS-Riso	Field	Ammonia	Jet	16	Aerosol
BA-Hamburg	Wind tunnel	Sulphur hexafluoride	Continuous instantaneous	146	Obstacles, slopes
BA-propane	Field	Propane	Jet-cyclone	51	Aerosol, fences
BA-TNO	Wind tunnel	Sulphur hexafluoride	Continuous instantaneous	13	Fence
Thorney Island	Field	Freon	Instantaneous	30	Fence, building
EMU-Enflo	Wind	Krypton	Continuous	2	Building, real site

Table 36: Arcwise Comp: Fractional Results w/in a Factor of Two of Experimental Results

[Carissimo, et al. (2001)]

MODEL TYPE				
Case with:	Workbook	Integral	Shallow-layer	CFD
No effect	0.40	0.74	0.65	
Obstacle	0.42	0.79	0.53	0.89
Aerosols	0.43	0.69	0.32	0.75
Terrain		0.33	0.67	0.71

Table 37: Pointwise Comp: Fractional Results w/in a Factor of Two of Experimental Results

[Carissimo, et al. 2001]

MODEL TYPE				
Case with:	Workbook	Integral	Shallow-layer	CFD
No effect	0.40	0.42	0.47	
Obstacle	0.30	0.34	0.34	0.54
Aerosols	0.31	0.39	0.36	0.55
Terrain		0.43	0.53	0.77

3.1.3 Model Directory

The Office of the Federal Coordinator for Meteorology (OFCM) has published a directory of a number of transport and dispersion models for the release of hazardous materials into the atmosphere [http://www.ofcm.noaa.gov/atd_dir/pdf/frontpage.htm]. An in-depth compilation and description of the models are provided, as well as model validation and verification information. No assessment or comparison of model performance is provided.

4 POOL FIRE AND VAPOR CLOUD STUDIES

LNG pool and vapor cloud fire experiments and their results are summarized in Table 38. A detailed description of these experiments is provided in the following sections.

Table 38: Large Scale LNG Fire Studies

STUDY	SPILL TERRAIN	SPILL VOL. (m^3)	SPILL RATE (m^3/min)	POOL DIA. (m)	SURFACE EMISSIVE POWER (kW/m^2)		BURN RATE (10^{-4} m/s) OR kg/m^2 s	FLAME SPEED FOR VAPOR CLOUD FIRES (m/s)
					Pool fire	Vapor cloud fire		
U.S.CG China Lake Tests	Water	3 – 5.5	1.2 – 6.6	15 (max)	220 ± 50	220 ± 30	4 – 11 (measured) (.18 – .495)	8 –17 (relative to cloud)
Maplin Sands	Water	5 – 20	3.2 – 5.8	30 (effective)	203 (avg) (178–248 range)	174 (avg) (137–225 range)	2.1 (calculated) (.0945)	5.2 – 6.0
Coyote	Water	14.6 - 28	13.5 – 7.1	Not measured	Not measured	150 - 340	Not measured	30 – 50 (near ignition sources – decayed rapidly with distance)
Maplin Sands	Land	No report	NA	20	153 (avg) 219 (max)	NA	2.37 (measured) (0.106)	NA
Montoir	Land	238	NA	35	290 – 320 (avg narrow angle) 257-273 (avg wide angle) 350 (max)	NA	3.1 (measured) (0.14)	NA

4.1 LNG Fire Experiments over Water

U.S. Coastguard China Lake Tests – 1978 [Schneider 1979] [Raj et al. 1979] [Schneider 1980]

A series of 16 tests were performed spilling 3-5.5 m^3 of LNG onto water with spill rates of 0.02-0.11 m^3/s at the Naval Weapons Center. The objective of the tests was to measure the thermal radiation output of two types of LNG fires over water, pool fires and vapor cloud fires. Three type of experiments were performed: immediate ignition of the LNG pool, delayed ignition in which ignition occurred after the spill started but before the evaporation was complete, and downwind ignition of the vapor cloud. Of the 16 tests, 7 were pool fire tests, 3 were delayed ignition tests, and 6 were vapor cloud fire tests.

For pool fires, spot surface emissive powers were obtained near the base of the flame indicating a value of 210 ± 20 kW/m^2 using narrow angle radiometers, and average emissive power for the entire surface of the flame was 220 ± 50 kW/m^2 using wide angle radiometers. These values represent averages over all tests. The percentage of methane in the LNG used for each test varied from 75 to 95 %. The highest spot emissive power of 250 kW/m^2 occurred with the highest concentration of methane. Average flame heights varied from 25 to 55 meters and fluctuated ±10 m for individual tests. The average flame length to diameter ratios varied from approximately 3 to 4, with a peak value of 6. A maximum pool fire diameter of 15 meters was observed.

For the delayed ignition tests, the fire failed to spread rapidly through the fuel, even when multiple flares were used as ignition sources, so that an optically thick flame was not established.

For the vapor fires, surface emissive powers were obtained indicating a value of 220 ± 30 kW/m^2, using narrow-angle radiometers, and 200 ± 90 kW/m^2, using wide-angle radiometers. Vapor fires were observed to propagate along the ground back towards the pool. The flame height to width ratio averaged about 0.5. Flame speed relative to the gas cloud varied from 8 to 17 m/s. Fireballs were not observed for these spill sizes.

The measured regression rates varied from $4x10^{-4}$ to $11x10^{-4}$ m/s. For higher spill rates, it was observed that the regression rates were higher, speculated as possibly due to the interaction between the jet and water effectively increasing the heat transfer area.

<u>Maplin Sands Tests – 1980</u> [Mizner and Eyre 1983] [Hirst and Eyre 1983]

Tests were conducted on extensive tidal mudflats at Maplin Sands, England by the National Maritime Institute and sponsored by Shell. These tests were performed to obtain dispersion and thermal radiation data on 20 spills of 5 – 20 m^3 of LNG and 14 spill of 13-31 m^3 of propane onto water. The spill point was surrounded by a 300 m diameter dyke to retain the tide. Twenty-four continuous and ten instantaneous spills were performed. Wind speed and direction, relative humidity, and radiation measurements taken with 26 wide-angled radiometers were recorded. Tests were performed in wind speeds from 4 to 8 m/s.

In only 11 tests ignition was possible, 7 LNG and 4 LPG, due to various difficulties. This could be due to the ignition points placed at cloud peripheries where inhomogeneous and lean burn regions exist. Thus, some ignitions did not result in sustained burns. Ignition points were placed 90 to 180 m downwind of the spill point. Radiation and diffusion flame analysis results were reported for 4 LNG tests. Of the four tests reported, 3 were continuous spills with a spill rate range of 3.2-5.8 m^3/min with a spill duration up to 1 minute, and one instantaneous with a spill volume of 12 m^3.

In all of these tests a vapor cloud fire developed, and for one test the vapor cloud fire propagated back to the spill point for a pool fire to form. This pool fire lasted only for a few seconds before the fuel ran out and did not have time to develop completely. As noted by the authors incomplete photographic records also made the analysis of this test difficult. In order to determine surface emissive power the pool fire was modeled as a tilted cylinder. An effective pool diameter was calculated by approximating the actual flame base area as an ellipse. An effective pool diameter of 30m (crosswind) was calculated for the LNG pool fire. From this test, an approximate fuel regression rate of 2.1 $x10^{-4}$ m/s was calculated. For the LNG pool fire, an average surface emissive power of 203 kW/m^2 with a range of 178-248 kW/m^2 was measured.

The flame propagated in the vapor cloud in two modes: as a pre-mixed weakly luminous flame that moved downwind from the ignition point, and as a luminous diffusion flame that moved upwind and propagated through the fuel-rich portions of the cloud and burned back gradually to the spill point. Video recordings indicated that pre-mixed burning took place in gaps in the vapor cloud and that the fuel/air concentration was not homogenous. Expansion of the combustion products principally took place vertically.

Diffusion flame propagation speeds of 5.2-6.0 m/s, and average pre-mixed flame propagation speeds of 5 m/s moving with the wind, were measured. The wind speed range was too narrow to determine possible flame propagation dependency on wind speed. Flame generated overpressures were under 0.4 mbar.

In one continuous spill test the pre-mixed flame propagated through the vapor cloud up to 130 m from the spill point. The flame height-to-width ratios of the vapor cloud fires were in the range of 0.2 to 0.4. For vapor cloud fires, an average surface emissive power of 174 kW/m^2 with a range of 137-225 kW/m^2 was measured.

Coyote Tests – 1981 [Rodean et al. 1984]

The Coyote tests were performed by LLNL and Naval Weapons Center at China Lake, California and sponsored by the U.S. DOE and the Gas Research Institute. The burning of vapor clouds from LNG spills on water were studied in order to determine fire spread, flame propagation, and heat flux. Data on 4 spills of 14.6-28 m^3 with flow rates of 13.5-17.1 m^3/min were performed with fuel of varying ratios of methane, propane, and ethane. Tests were performed in wind speeds from 4.6 to 9.7 m/s and atmospheric stability conditions from unstable to neutral. Gas concentration measurements were averaged over a 2 s period.

The ignition point was located near the cloud centerline about 60 to 90 m downwind of the spill source, and ignition was performed using either a flare or a jet. The flames were observed to begin near the center of the cloud and propagate radially outward, downwind and upwind toward the spill source. Both visible yellow luminous and transparent flames were observed. Pool fires occurred but measurements were not taken.

It as found that the pre-ignition 5%-gas-concentration contours are not indicative of the potential burn area and its location. The actual burn area was observed to propagate further downwind and to the sides than indicated by the pre-ignition contours. The instantaneous 5% gas concentration contours closely coincided with the burn region when 2-s-averaging of concentration measurements were used.

In the test with the highest flow rate or total volume spilled (17.1 m^3/min or 28 m^3), rapid phase transition (RPT) explosion increased the distance to the downwind LFL by about 65% and the total burn area by about 200%. The flame extended up to 280 m downwind and had a maximum width of 60 m. The authors note that the increase was caused by an increased source rate and by enrichment in higher hydrocarbons. The puffs of vapor from the RPT explosions cause momentary increases in concentration as they propagate downwind.

The test conducted in the lowest wind speed and most stable atmospheric conditions had the broadest vapor fire cloud with a maximum width of 130 m and downwind distance of 210 m, and it displayed a bifurcated structure.

Flame heights appeared to vary directly with the pre-ignition height of the combustible mixture near the ignition source. The ratio of flame height to cloud height varied from 5 to 10. The clouds were 3-8 m in height. Flame speeds with peak values of 30 m/s were observed near weak ignition sources and 40-50 m/s for strong ignition sources. Speed decreased as a function of distance from the source and no flame acceleration was observed. Overpressures of only a few millibars were measured, not enough to cause damage.

Heat flux (radiative and convective) measurements inside the vapor cloud fires were found to be in the range of 150-340 kW/m^2. External radiative flux values for the bright yellow portion of the flames were in the range of 220-280 kW/m^2 using wide and narrow-angle radiometers. These measurements were noted as being suspect because the sensors were not protected by a heat sink or water-cooling. This resulted in the sensors heating up and the signal becoming distorted as the heat load increased. This was true for all but one test that did not have the sensor engulfed by the flame.

4.2 LNG Fire Experiments Over Land

Maplin Sands Tests – 1982 [Mizner and Eyre 1982]

Tests sponsored by Shell were performed to measure the thermal radiation from 20m diameter land-based pool fires of LNG, LPG and kerosene using both wide and narrow-angle radiometers. The following were also measured: mass burning rate, fuel composition, wind speed and direction, relative humidity, and metal surface temperatures close to the fire. Video and still photographs were taken upwind and crosswind of the fires. The average surface emissive power was determined by measurements made using wide-angle radiometers and the use of a solid flame model representing the flame as a tilted cylinder. One test was performed for each fuel.

The flame appeared roughly cylindrical in shape and tilted due to a 6.15 m/s wind. For the LNG fire the production of black soot appeared much higher in the flame and was significantly less than that produced by LPG or kerosene. The measured mean flame length using video recordings for the LNG fire was 43 m with a flame length-to-diameter ratio of 2.15. The Thomas correlation for flame length-to-diameter ratio predicts a value of 1.88, if the measured burning rate is used, underestimating the observed mean flame length by 12.6%. The measured burning rate was 0.106 kg/m^2s (2.37×10^{-4} m/s) for LNG, versus 0.13 kg/m^2s (2.17×10^{-4} m/s) for LPG.

The average surface emissive power for the LNG pool fire was 153 kW/m^2, while LPG had a much lower value of 48 kW/m^2, due to the greater smoke shielding. The maximum measured value using narrow-angles radiometers for the LNG fire gave values up to 219 kW/m^2.

<u>Montoir Tests – 1989</u> [Nedelka et al. 1989]

These tests were collaboration among many sponsoring companies: British Gas, British Petroleum, Shell, Elf Aquitaine, Total CFP, and Gaz de France with tests performed by British Gas, Midlands Research Station, Shell, and Thornton Research Center. Tests on 35m diameter LNG pool fires on land were performed at a facility near the Montoir de Bretagne methane terminal.

Three LNG pool fire experiments over a wind speed range of 2.7 to 10.1 m/s were performed. The maximum volume of LNG poured into the 35 m diameter bund was 238m^3. The following were measured: flame geometry, incident thermal radiation at various ground level positions, spot and average flame surface emission, gas composition in pool, fuel mass burning rate, and flame emission spectra in both the visible and infrared regions.

Small regions of the flame were examined using a narrow angle radiometer. These measurements correspond to ‘spot surface emissive power’ values, whereas average surface emissive power measurements use wide angle radiometers and refer to an average over the flame surface and are interpreted based upon the flame shape. Two types of average surface emissive powers were employed: one based upon an idealized cylindrical flame shape that includes the smoky part of the flame, and the other based from cine photographs that represent the actual areas of clear flame.

A mass burn rate for a methane fire was obtained as long as the methane concentration in the pool was above 40%, or when vapors above the pool were measured to have at least 99-mole percentage methane content. During the methane pool fire burn time, the ethane content in the vapors above the pool was less 0.2-mole %. Keeping the methane content in the pool above 40% avoided the high smoke shielding that can occur from the ethane or propane in the fuel and the decrease in the mass burn rate from the increased conduction into the fuel due to higher boiling points of ethane or propane.

It was observed that the fires had an intensely bright region extending from the base to at least half of the total flame height, and the rest was obscured intermittently by smoke, which was much more than that produced in a 20m diameter LNG fire. The shape of the fire was observed to be complex and was noted as difficult to represent using simple geometries.

The average mass burning rate among the 3 fires was 0.14 kg/m^2s.

Flame drag ratios up to 1.29 for high wind speeds, and 1.05 for low wind speeds were measured. Flame drag ratio is defined as the flame base length in the direction of the wind divided by the pool diameter

At 140 m from the burn center, the incident thermal flux was measured as approximately 15 kW/m^2 downwind, 5 kW/m^2 crosswind, and 3 kW/m^2 upwind during a wind speed range of 7.0 – 10.1 m/s.

In the lower 10 m of the flame, typical time averaged spot surface emissive powers of 290 – 320 kW/m^2 were measured in the crosswind direction. Values up to 350 kW/m^2 averaged over 5 – 10 s periods were measured. These values are much greater than that of smaller pool fires where at comparable positions, values of 140 – 180 kW/m^2 for a 6.1m diameter fire and 170 – 260 kW/m^2 for a 10.6m diameter fire has been observed.

Average surface emissive power values in the range of 230 – 305 kW/m^2 from individual instruments were measured. Average values for each experiment were in the range of 257 – 273 kW/m^2. These were based upon a flame shape using cine photographs. Values were also obtained by utilizing a flame shape based upon a tilted cylinder with length calculated from the Thomas equation and tilt angle from the Welker and Sleipcevich equation. The values obtained were much lower with a range of 130 – 180 kW/m^2. With both methods, the average surface emissive power was plotted for pool diameters of 6.1, 10.6, 20, and 35. The graph indicated that the rate of increase of the average surface emissive power for increasing pool diameter is decreasing. The authors note that it is not expected that a much greater value would be obtained for larger pool fires.

4.2.1 Models

Generally, three approaches can be identified to model thermal radiation from pool fires. These models are classified as point source, solid flame, and field. Schneider provides a review of the first two models and various vapor cloud and fireball models pertaining to LNG [Schneider 1980].

The simplest model is the point source model, in which the emission of thermal radiation is treated in a global manner by assuming the radiation source is a point and that the radiation decays as the inverse square of the distance from the source. An assumed fraction of the heat of combustion is used to approximate the thermal radiation emitted, the uncertainty of which increases with large pool fires due to the lack of data. It is also assumed that the receiving surfaces are oriented to receive the maximum thermal radiation. The near field, approximately 3 – 5 diameters, cannot be captured with this model because the geometric considerations between the emitting flame and receiving surfaces become important. Radiation attenuation in the atmosphere is also not accounted for with this model. The effects of wind tilting the flame and the presence of objects interacting with the flame cannot be captured. This model is not a typical approach used today, but was a first attempt to capture the thermal radiation from pool fires.

The next level of complexity is the solid flame model, which configures the surface of the flame with a simple geometry, usually cylindrical [Brown et al. 1974] [Raj and Atallah 1975] [Lautaski 1992] [Johnson 1992]. The thermal radiation is emitted uniformly from this surface and the total radiant power is based upon empirical correlations with pool diameter. Modeled is the geometric view factor, which is the fraction of radiant energy that is received by an object's field of view. Also accounted for is the attenuation of the thermal radiation in the atmosphere. In order to capture the tilting of the flame due to wind, a tilted cylindrical flame shape is typically used. Flame length, tilt and drag necessary to determine flame shape and view factors, are based upon empirical correlations. For pool fires with simple pool geometries, these models provide good agreement with experiment. Johnson found agreement within one standard deviation from the average measured heat flux for a range of pool sizes, 1.8 – 35 m in diameter. The disadvantage of these models is the inability to model more complex flame shapes such as those arising from complex pool shapes or object interaction with the flame.

The most sophisticated models are the validated field models (CFDs) that incorporate the equations that govern fluid flow; that is, Navier-Stokes. Because pool fires are turbulent for the scale of interest, turbulence models are used, typically the k-epsilon model. Combustion models typically assume that combustion is mixing-controlled, rather than controlled by the chemical reaction time. The radiant transport equation along with simplifying assumptions is used to model thermal radiation. Soot models are also incorporated, which invoke empirical models.

Simplified models, such as the solid flame model, have been typically used for thermal hazard zones that assume a circular pool. The point source model has also been used, which assumes that the fire originates from a point, implying that the pool is uniform from the point. For a spill scenario with no object interaction, this is a logical geometrical shape to assume for the pool. If there is object interaction, an oval or rectangular configuration could occur; for example, a trench fire, which is a pool fire with a rectangular configuration. It is of interest to compare the performance of the point source model and solid flame model to such a configuration. Thus, both models were compared to a trench fire [Croce et al 1984].

Comparison was made with a trench dimension of 23.5 x 1.83 meters. The measured wind speed was 1.83 m, average flame length 3.4 m, flame tilt 56.8 degrees, flame drag ratio 2.96, burning rate .054 kg/m^2 s, and average surface emissivity of 135 kW/m^2. The radiative fraction used for the point source calculation was .348, based upon a relation by Moorhouse and Pritchard for radiative fraction as a function of surface emissive power and flame height to diameter ratio. The effective pool diameter is 7.4 m for the given trench dimensions. Thus, the surface emissive power and flame height to diameter ratio was taken into account through the radiative fraction value. The flame height to diameter ratio of 1.49 was calculated using a Moorhouse correlation that includes the effect of wind. The measured burn rate value from experiment was also used for the point source calculation. The view factor for a tilted cylinder to an object was calculated by formula derived by Sparrow [Sparrow 1963].

Figure 10 indicates that both models over predict the measured heat flux at most crosswind, upwind, and downwind locations. The point source model slightly under predicts the heat flux at intermediate distances. The comparison to downwind provides the best agreement to experiment, about five pool diameters from the pool center for the point source model. The percent difference between the experimental data and the point source model results for heat flux measurements downwind range from 4 to 30%, crosswind from 33 to 228%, and upwind from 218 to 293%. The solid flame model predicts a much higher heat flux value, because the predicted flame height for the assumed circular pool is much higher than the experimental value, 11 m vs. 3.4 m. Thus, the discrepancy can principally be attributable to flame break up.

The experiments showed the flame breaking up into flamelets, or individual fire plumes. Thus, the flame height is shorter than that of a circular pool fire with equivalent area. This comparison indicates that the point source model and the solid flame model do not accurately predict heat flux levels when the pool is non-uniform, such as would occur when there is object interaction.

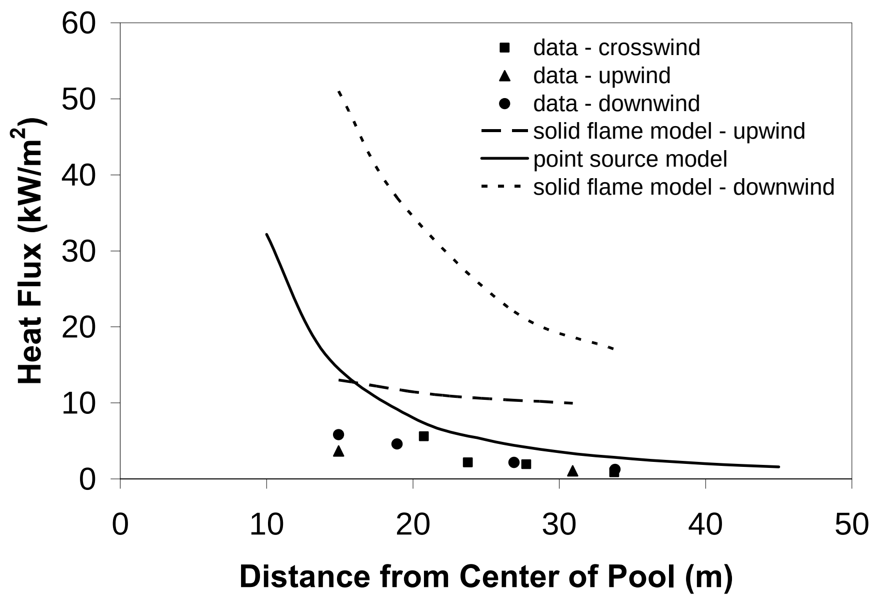


Figure 10. Flame Model Comparison with Trench Fire Data

The disadvantage of field models is the computational running time compared to integral models that represent the fire as cylindrical flame. Although, with the emergence of more powerful computers, this is less problematic. These codes can now be run on personal computers and workstations, instead of super computers. The advantage of field models is that complex flame shapes can be captured, such as that arising from object/flame interaction as from an LNG ship and a pool fire, for example. Vapor cloud fires and fireballs can also be modeled with these codes.

Various field models are available, such as FLACS, CFX, Phoenics, Kameleon, and Vulcan. These codes vary in their capability to model explosion, fireballs, flash fires, and/or pool fires.

4.3 Detonation Studies

U.S. Coastguard China Lake Tests – 1978 [Parnarouskis et al. 1980] [Lind and Witson 1977]

Tests were performed in a detonation tube and 5m and 10m radius hemispheres. Both explosive-initiated and spark-ignited tests were performed on methane-air and methane-propane mixtures. For the detonation tube experiments, the methane-air mixture did not detonate using a 5 g or 90 g booster, nor did it detonate with spark ignition. Methane-air mixtures did not detonate with explosive charges up to 37 kg for the 10m diameter hemisphere tests. Methane-propane mixtures of 60-40, 70-30, and 85-15 did detonate using a 1 kg high explosive booster for the 5m hemisphere tests

Experiments were also performed to test a postulated accident scenario in which the vapor formed during an LNG spill mixes with air to form a flammable mixture and then diffuses into a culvert system. The mixture in the culvert ignites and the combustion wave accelerates then transitions to a detonation that exits the culvert and detonates the remaining unconfined vapor cloud. The detonation charge used in the culvert was a 13 kg explosive. Detonations in the vapor mixture occurred when propane concentrations were 6% or greater and the culvert measured 2.4 meters in diameter. From these detonations, the shock wave was felt at a town 22 km from the test site.

Vander Molen and Nicholls – 1979 [Vander Molen and Nicholls 1979]

Experiments were performed to measure the effect of ethane addition to methane air clouds on detonation. A stoichiometric mixture with air was maintained for every mixture of methane and ethane tested. The ethane concentration ranged between 0 and 5.66% by volume of the total methane-ethane-air mixture or, equivalently, 10% to 50% by volume of the fuel mixture. The experiments were performed using a sectored shock tube of 147.6 cm radius and 5 cm width to model a 20-degree pie shaped sector of a cylinder cloud. A stable detonation was characterized as a wave propagating with a non-decaying constant velocity. For an ethane content of 1% by volume in the methane-ethane-air mixture or a 10% ethane by volume content in the fuel, 5.5 grams of condensed explosive or critical initiating blast energy of 25,000 J/cm was needed to result in a detonation.

4.3.1 Reviews

There have been several reviews on detonations of hydrocarbon/air mixtures [Lee and Moen 1980] [Moen 1993] [Nettleton 2002]. It was pointed out by Moen that weak ignition of vapor clouds in an unconfined and unobstructed environment is unlikely to result in a deflagration to detonation (DDT), even for more sensitive fuel/air mixtures; but it is likely with confinement and the presence of obstacles [Moen et al. 1980]. The occurrence of DDT depends upon the degree of confinement, obstacles configuration, ignition source, initial turbulence, and the fuel-air mixture. Nettleton indicates that the understanding of how confinement, temperature, pressure, and mixture composition influence the initiation source and distance to DDT is not complete. Further work must be done before prediction can be made whether DDT will occur for any given spill scenario.

4.3.2 Flame Acceleration Studies

Moen et al. – 1980 [Moen et al. 1980]

This is a series of works performed at McGill University in Montreal, Canada, on flame acceleration and deflagration to detonation transitions [Chan et al. 1983]. The influence of obstacles on flame acceleration of methane/air mixtures was investigated in a cylindrical vessel 30.5 cm in radius. The effect of obstacles was to increase flame speed of up to 130 m/s, 24 times the velocity without obstacles. The high flame speeds could only be maintained with repeated obstacles, which provide large-scale flow field distortions associated with flame acceleration.

Urtiew – 1982 [Urtiew 1982]

The work was motivated by the possibility that terrain or obstacles might create semi-confined flame paths that could lead to flame acceleration. Flame acceleration of propane-air mixtures in semi-confined geometries with obstacles was investigated. Propane-air mixtures were spark-ignited in an open top and end test chamber, 90 cm long, 30 cm high, and 15 cm wide. It was found that obstacles caused the flame to accelerate from 2 – 3 m/s up to 4 – 6 m/s. Further flame acceleration up to 20 m/s occurred when the obstacles were raised slightly above the chamber floor and by varying the location of the ignition source. It was concluded that further work is needed to determine the mechanisms leading to continuous acceleration in semi-confined geometries.

Harrison and Eyre – 1987 [Harrison and Eyre 1987]

A series of tests was performed to investigate the effect of obstacle arrays on flame acceleration of pre-mixed natural gas/air and propane/air mixtures. A wedge-shaped enclosure was used which had an open top and bounding sidewalls forming a 30 degree wedge of 30 meters long and 10 meters high. This aspect ratio was used so that a shape representative of a dense cloud would be modeled.

A series of horizontal pipes were placed in the wedge to provide optimal flame acceleration. Blockage ratios of 20 and 40 percent based upon the percentage of the obstacle grid were used. Unobstructed and obstructed tests were performed using a low energy fuse head igniter. The effect of grid height, blockage ratio, grid spacing, and the total number of grids was investigated. Unobstructed LNG/air mixtures produced low flame speeds of 8 – 9 m/s in the first few meters and overpressures of 4 – 5 mbars, which decayed with a 1/r relationship in the far field.

Grids with low blockage ratios or low height produced overpressures of 29 – 63 mbars decaying as 1/r and flames speeds of 37 – 51 m/s, not sufficient to cause severe structural damage. The test with the great congestion obtained a maximum flame speed of 119 m/s and overpressure of 208 mbars decaying as 1/r, which can be sufficient to cause structural damage to buildings in the immediate vicinity of the cloud. In all tests, flame speed and overpressures decayed rapidly after the flame emerged from the grid of obstacles, typically within 5m of the last grid. Thus, the size of the obstacle array, not the size of the gas cloud, defined the size of the pressure source.

Shell – 2001 [Bradley et al. 2001]

Flame acceleration was investigated in a vented box structure, 10 m long, 8.75 m wide, and 6.25 m high using methane/air and propane/air mixtures ignited using a conventional spark plug. Results indicate that an initial stable and subsequent unstable flame propagation regime occurs. In the unstable regime, instabilities grow to wrinkle the flame and increase the flame speed. Flame speed measurements up to a radius of approximately 3 m indicate that flame speed increases with radial distance and varies as the square root of time. Past this distance, the walls of the test structure interfered with flame propagation.

5 DISCUSSION

There are many theoretical and experimental gaps related to understanding the dynamics and subsequent hazards of an LNG spill on water. Filling some of the gaps is currently impossible due to experimental and computational limitations. The following discussion addresses gaps that can be filled with current capabilities, and is indicative of first priorities to improve abilities to address hazards associated with an LNG spill.

There is a large disparity between the available experimental data and the scales of interest. Figure 11 shows a comparison of the spills sizes tested to date and that are possible from a single LNG cargo tank for a large hole. Table 38 specifies spill volumes tested, spill rate, pool radius, and distance to LFL for these various tests. The available experimental results are two to three orders of magnitude less than the scales of interest. It is evident that there is a lack of large-scale spill data for model comparison.

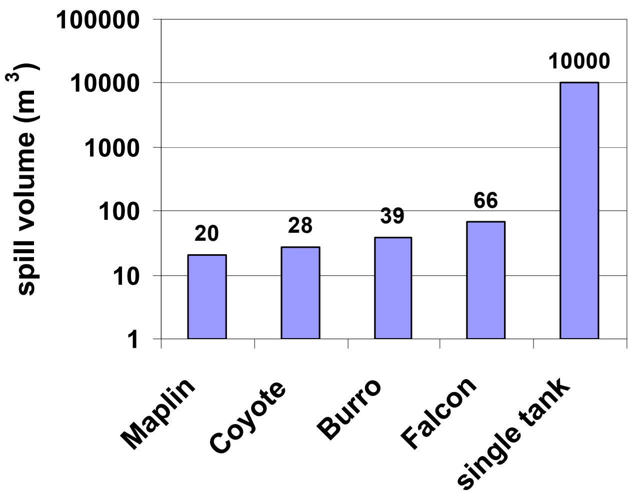


Figure 11. Log Scale Comparison of Experimental Spills vs. Possible Cargo Tank Spills

- Of the larger spill tests performed, there have been only a few LNG pool fires on water tests where measurements were taken. This was for a spill size of 10.35 m^3, which is far below the spill volume that could occur for a 2 or 12m^2 hole in one tank of a vessel. This pool fire lasted only for a few seconds before the fuel ran out and did not have time to fully develop. It was also noted that photographic records necessary for analysis were incomplete. In order to determine the thermal radiation hazard from a pool fire, the surface emissive power needs to be determined. The pool fire tests on land indicate that the surface emissive power increases for pool diameters up to 35 m. Whether the maximum surface emissive power was obtained is uncertain, though most likely it isn’t much higher than that measured for 35 m. It is difficult to determine whether the surface emissive power and the pool mass flux has leveled off for pool fires on water since only one test of a larger scale has been performed. Thus, more data on large-scale LNG pool fires on water is needed. More tests on the order of spill volumes of 10 m^3 should be performed, and ideally on the order of 100 m^3, so that maximum surface emissive powers and pool mass fluxes are reached. Also, at these larger scales, a regime may be revealed at which a single coherent pool fire cannot be maintained, but rather a break up into multiple pool fires occurs.

- LNG pool fire simulations on water using a field or validated CFD dynamics code have only recently begun to be used. These codes can capture object interaction with the flame as well as vapor cloud fires. A simulation of a pool fire and its impact on the LNG ship will provide improved estimates of cascading damage.
- Probability of ignition of the LNG from initial damage is uncertain for some initiating events and should be experimentally investigated.
- It is questionable whether the spill sizes investigated to date give an indication of the atmospheric dispersion that would occur for very large spills. The significance of the Burro tests results for the dense cloud displacement effect is that the cloud does not dissipate as quickly due to the lack of turbulent mixing and thus will persist for a longer time. This result has hazard implications that might be more profound for very large spills in which the mass of the dense cloud will be greater.
- The achievable overpressures of RPT explosions for very large spills (~ 100 m^3/min) and the possible upper bounds of damage to structures have not been evaluated.
- Determining the spreading and vaporization of the LNG pool is instrumental in determining the evolution of the vapor cloud and subsequent related hazards. If this part is performed incorrectly, the rest of the analysis is severely affected. This feature was evident from the recent four studies that were compared. The prominent issue raised from the comparison is the effect of waves on spreading and vaporization. Wave action would increase the evaporation rate due to the increased surface area and increased heat transfer rate from the lower levels of the water due to the mixing action of the waves. Traveling waves would irregularly spread the LNG pool. The effect of waves on spreading and vaporization should be investigated experimentally, and a free-surface code such as FLOW-3D should be used to simulate spills at the larger scales.

APPENDIX D
SPILL CONSEQUENCE ANALYSIS

1 INTRODUCTION

]A wide range of experimental information on LNG spills and associated analyses must be considered and evaluated in an effort to assess the potential consequences of the breach and associated spill of an LNG cargo tank. The consequences or potential hazards to the public of a large LNG spill over water will depend on:

- Potential damage to an LNG cargo tank from either an accidental or intentional breach and the size, location, release rate and volume of LNG spilled;
- Environmental conditions such as wind, tides and currents, and waves that could influence the spread or orientation of a potential LNG spill over water;
- Potential hazards resulting from an LNG spill over water, such as cryogenic damage or thermal damage to the vessel or other LNG cargo tanks, which might lead to cascading failures of additional LNG cargo tanks or several damage to the LNG vessel;
- The location and magnitude of a potential LNG spill where the hazards from a spill, such as fire and thermal radiation, might impact or damage other critical infrastructures or facilities such as bridges, tunnels, petrochemical or power plants, government buildings or military facilities, national icons, or population or business centers; and
- Potential impact on the regional natural gas supplies from the damage of an LNG vessel, unloading terminal, or loss of use of a waterway or harbor due to the immediate or latent affects of a spill.

The risk-based assessment approach discussed in Section 3 of the main body of this report and the event tree in Figure 4 was developed for potential LNG breaches and associated consequences, and provides the basis for evaluating the potential events that might ensue from either an accidental or intentional breach of an LNG cargo tank and are discussed in this Appendix.

2 ASPHYXIATION POTENTIAL AND IMPACTS

Methane, an ingredient of LNG, is considered a simple asphyxiant; but it has low toxicity to humans. In a large-scale LNG release, the cryogenically cooled liquid LNG would begin to vaporize upon its release due to the breach of an LNG cargo tank. If the vaporizing LNG does not ignite, the potential exists that the LNG vapor concentrations in the air might be high enough to present an asphyxiation hazard to the ship's crew, pilot boat crews, emergency response personnel, or others that might encounter an expanding LNG vaporization plume.

To date, experimental data show that vaporization from an LNG spill tends to spread essentially in a cigar-shaped, disk pattern due to the high-density characteristics of LNG. The vapor cloud spreads out in a mostly broad, flat configuration, generally with a plume of

10 – 30 feet in height. This is much different from the traditional Gaussian-type distributions, most often assumed for atmospheric dispersion of many common pollutants.

Beard described a study of the effects of hypoxia on the cognitive abilities of 100 test subjects in a low-pressure chamber. The threshold for reduced mental performance occurred at an oxygen partial pressure of 85 torr for three of the test subjects. This is equivalent to an oxygen concentration of 11.1 % at sea level. Approximately 75% of the test subjects showed reduced mental performance at 65 torr oxygen pressure, which is equivalent to 8.5 % oxygen at sea level. These data were most likely obtained on a cohort of physically fit, medically qualified individuals.

ANSI Z88.2-1992 provides the data in Table 39 for inhalation of air that is deficient in oxygen [ANSI 1992].

Table 39: Response of a Person to Inhalation of Atmosphere Deficient in Oxygen

% O_2 AT SEA LEVEL	OXYGEN PARTIAL PRESSURE (mmHg)	PHYSIOLOGICAL EFFECTS
20.9	159	Normal
19	144	Some adverse physiological effects, but they are unnoticeable.
16	121	Impaired thinking and attention. Reduced coordination.
14	106	Abnormal fatigue upon exertion. Emotionally upset. Faulty coordination. Poor judgment.
12.5	95	Very poor judgment and coordination. Impaired respiration that might cause permanent heart damage. Nausea and vomiting.
<10	<76	Inability to perform vigorous movement. Loss of consciousness. Convulsions. Death.

ANSI Z88.2-1992 requires air-supplying respirators for workers who enter an atmosphere having less than 16% oxygen at sea level. The ANSI standard assumes that nearly all workers will be able to escape from an atmosphere having 16% oxygen, even if it requires a moderate amount of exercise, such as climbing a ladder. When oxygen concentrations are less than 19.5% oxygen at sea level, ANSI Z88.2-1992 requires workers to use air-supplying respirators that have an emergency air supply for escape purposes. It assumes that some workers will be injured or debilitated by a 12.5% oxygen atmosphere, to the point at which they could not escape. ANSI's recommendations are intended to protect nearly all workers; and it assumes that workers are medically qualified and fit for duty. Workers are, on average, more fit than the general population.

To summarize, any reduction in oxygen concentrations will carry some risk to the population, because there will always be sensitive individuals. These probably include people with pulmonary or heart disease. On the basis of the references that were reviewed, it appears that minimal permanent injuries or deaths should occur in a physically fit and medically qualified population from a transient release of methane, if oxygen concentrations do not drop below 12.5% at sea level. If concentrations do not drop below 14% oxygen at sea level, the frequency of permanent injuries or deaths in the general population should be minimal as well. Of greater issue will be the potential for a fire from ignition of an LNG cloud.

3 CRYOGENIC SHIP DAMAGE: POTENTIAL AND IMPACTS

As noted in Appendix B, a range of LNG cargo tank breaches were calculated from the analysis of credible accidental and intentional breaching events. The size and location of potential breaches were used as a basis for the analysis of the potential for cryogenic damage to the structural steel of an LNG ship from a spill in the absence of a fire. Contact of steel with cryogenic fluids is known to cause embrittlement, which can significantly reduce the strength of steel [Vaudolon 2000]. A detailed structural analysis was beyond the scope of this review; but structural integrity embrittlement scoping analyses were conducted to assess the potential damage to an LNG ship from small and large LNG spills based on available fracture mechanics data and models. These analyses were guided by available information on LNG ship and tank designs, construction, and structural steel material property data [Linsner 2004] [Shell 2002] [Wellman 1983].

A review of the structural steel used in LNG ship fabrication shows extensive use of ABS-Class A, B, and C structural ship steel [Linsner 2004]. In discussions with the U.S. Coast Guard, ABS Class E and F structural steels are also being used in some newer LNG ships. Selected material properties for ABS Class B steel include [Wellman 1983] room temperature yield strength equal to $37x10^3$ psi., coefficient of thermal expansion equal to $8.3x10^{-6}$ in/in °F, Young's modulus (E) equal to $30x10^6$ psi. As with all low alloy carbon steels, A131 class B and C transition from ductile to brittle behavior with decreasing temperature. Lower shelf (brittle) behavior starts at about 32°F. For these steels, the fracture toughness (Kc) decreases approximately linearly from $90x10^3$ psi√in at -60°F to $20x10^3$psi√in at –260°F.

This is approximately the lower bound of fracture toughness for all low alloy carbon steels at LNG cryogenic temperatures, as shown in the table below. Fracture toughness is a major influence on the structural integrity of steels that come in contact with cryogenic fluids. The lower the fracture toughness, the higher potential for damage that could be expected. Because fracture toughness data at LNG-type temperatures for steel used in ship construction is limited, the use of correlations and extrapolations from available fracture toughness data can provide useful estimates of fracture toughness for many of these steels. Two approaches were used to estimate expected fracture toughness values at LNG cryogenic temperatures for ship steels.

One method of estimating fracture toughness makes use of the "Barsom-Rolfe" two-step correlation between Charpy V-Notch (CVN) data and fracture toughness [Barsom and Rolfe 1987]. ABS – E and ABS – F steels have CVN values of 14 ft-lbs and 17-20 ftlbs respectively. Using the Barsom-Rolfe two-step correlation, this equates to a 46 ksi√in fracture toughness value for ABS E and a 55 ksi√in value for ABS F steel. Data suggests that for low alloy carbon steels well into the lower shelf behavior, the slope of the fracture toughness versus temperature curve can be taken to be 1 ksi√in/°F, down to a lower bound of 20 ksi√in. Using this correlation, both of theses steels approach the lower bound Kc of 20 ksi√in at -260 °F. This is the same value of Kc for ABS Class B steels.

An alternate approach to estimation of fracture toughness can be appropriated from the nuclear pressure vessel industry [Barsom and Rolfe 1987]. Here, a reference curve (K_{IR}) has been constructed from an extensive database of fracture testing on low alloy carbon steels with yield strength of less than 50 ksi. Fracture toughness as a function of temperature for steels typical of this class of materials is shown in Figure 12.

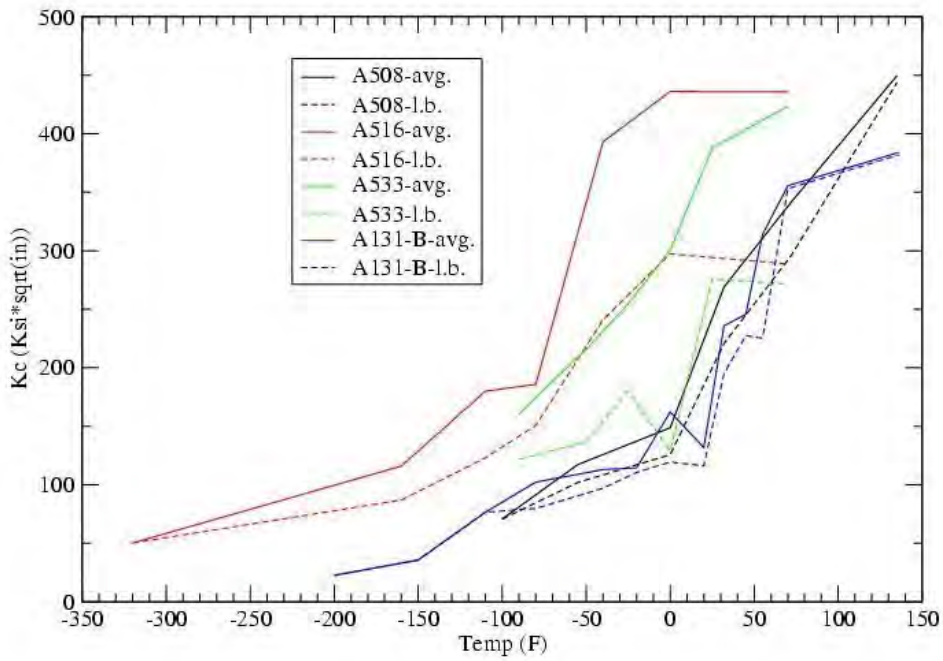


Figure 12. Fracture Toughness of Low Alloy Carbon Steels

This curve is represented by the following equation:

$$K_{IR} = 26.777 + 1.223e^{(0.0145[T - \{RT_{ndt} - 160\}])}$$

The basis of this equation is that all the fracture toughness data can be represented by a single curve with a temperature shift. That is, reference nil-ductility temperature, RT_{ndt}, for the steel of interest is the key to using this K_{IR} curve. The nil-ductility temperature is determined through drop weight testing. Alternately, it can be determined by CVN testing. RT_{ndt} is 40 ºF lower than the lowest temperature at which all CVN results have more than 40 mils lateral expansion. Unfortunately, neither of these data sets is available for ABS – E or ABS – F steels. In the absence of better data, a reasonable estimate for RT_{ndt} might be taken to be the temperature at which the steel has 15 ft-lbs of absorbed energy in a CVN test. For ABS – E, this is about - 40 ºF. For ABS F, this is about –80 ºF. Therefore, using the K_{IR} approach, the fracture toughness of ABS – E steel is estimated to be 27 ksi√in and ABS – F steel is 28 ksi√in. Note, in the K_{IR} equation above, the lower bound fracture toughness is taken to be 26.777 ksi√in rather than the 20 ksi√in assumed earlier. The fundamental conclusion is reinforced however. That is, at LNG cryogenic temperatures, all the ABS low alloy carbon ship hull steels are very near the lower bound fracture toughness for low alloy carbon steel.

Therefore, based on these two types of fracture toughness estimation techniques, regardless of steel type, all low alloy carbon steels approach this lower fracture toughness bound at

LNG cryogenic temperatures. This lower bound value was used to estimate potential thermal stress states in the ship structural steel for different types of breach and spill events.

Three cryogenic spill scenarios were computed for thermal stress, each of which can be related to a different type of breach event.

Scenario 1 (Small Spill)

The first scenario is a circular, through-thickness cold spot in a large, flat plate. This case could result from a spill of cryogenic material on one face of the plate while the other face is sensibly insulated (air or other lower heat transfer medium). The portion of the plate outside the cold spot provides constraint such that the region of the plate inside the cold spot is subjected to tensile stress to accommodate the thermal contraction due to the reduced temperature. The stress inside the cold spot can be computed from: [Goodier 1937]

$$\sigma = 0.5 \bullet \alpha \bullet \Delta T \bullet E$$

where σ = stress
α= coefficient of thermal expansion
ΔT= change in temperature
E= modulus of elasticity

Here, the resulting thermal stress is approximately 40×10^3 psi or roughly equivalent to the yield strength.

Fracture can be determined by equating the fracture toughness (K_c) with the fracture driving force (stress intensity: K_I). Stress intensity can be calculated from [Barsom and Rolfe 1987]:

$K_I = \sigma\sqrt{\pi a}$, where 'a' is the flaw size and σ is the stress level.

Rearranging this equation, the critical flaw size can be computed as:

$$a_{cr} = \frac{K_c^{\ 2}}{\pi\sigma^2}$$

The critical flaw size thus computed is about 0.1 inch. A crack-like defect of 0.1 inch would be rare in base metal plate material. However, in ship construction welding, such a flaw size could be relatively common. Once initiated, a flaw could be expected to propagate to the extent of the cold region and even some distance beyond. Thus, for a large penetration of a cryogenic LNG cargo tank and associated large spill, a large section of the ship structure could be fractured from the thermal insult alone, independent of other loadings (wave, blast, or shock).

Scenario 2 (Large, Internal Spill)

The second case considered is that of an entire structure at a low temperature supported by a structure of similar stiffness at a higher temperature. A penetration in the cryogenic LNG cargo tank, with the inner hull intact, could lead to the filling of the inner hull with the cryogenic liquid. If the ship is not ballasted, the space between the inner and outer hull would be filled with air or nitrogen, essentially an insulator. Thus, the inner hull would be at the cryogenic temperature, while the outer hull is at sea temperature. The inner and outer hulls are of comparable stiffness. The equation for computing stress in this case is identical to that for the cold spot discussed above. The thermal stresses, fracture toughness, critical flaw size, etc. are nearly identical to the case of the cold spot. The conclusion here is that a flaw could propagate through the entire inner hull, either from side-to-side or axially, from front containment bulkhead to aft containment bulkhead of the compromised compartment.

Scenario 3 (Spill Between Ship Hulls)

Finally, the third case is for a plate, stiffened such that no out-of-plane displacement (bending) can occur. The top surface is maintained at a low temperature, while the bottom surface is maintained at a higher temperature (e.g., LNG spill within the inner and outer hulls). The temperature gradient across the plate is linear. This case could result from a penetration through both the inner hull and the cryogenic tank. Leaking LNG would encounter the inside of the outer hull plate, while seawater would be in contact with the outside of the outer hull plate. The cryogenic material and the sea can be approximated as constant temperature boundary conditions. Here, the thermal stress is given by [Goodier 1937]:

$$\sigma = \frac{\alpha \bullet \Delta T \bullet E}{(1-\upsilon)}$$ where ‘υ’ is Poisson’s ratio

This equation results in an elastically computed stress significantly in excess of the room temperature yield stress ($100x10^3$ psi). No attempt was made to include nonlinear material properties (plasticity). However, due to plastic deformation, the actual stresses resulting from this case will be significantly less than the elastically computed $100x10^3$ psi., but still greater than the stresses resulting from the prior two cases. The potential for cracking is similar to the prior two cases.

For all three types of cryogenic spill events considered, the potential exists for progressive structural damage due to the thermal insult of the cryogenic liquid on the structural steel of the ship. The extent of the damage will depend on the volume and rate of LNG spilled and the ship areas that will be directly contacted by the liquid LNG. Based on the postulated breach events, attempts were made to estimate the potential level for ship damage from both accidental and intentional events. These are presented in the table below.

Table 40: Estimated LNG Ship Damage from Potential Tank Breaches & Spills

Breach Event	Breach Size	Tanks Breached	Ship Damage[b]
Accidental collision with small vessel	None	None	Minor[b]
Accidental collision with large vessel	5 – 12 m^2 (Spill area 0.5 – 1m^2)[a]	1	Moderate
Accidental Grounding	None	None	Minor
Intentional Breach	0.5 m^2	1	Minor
Intentional Breach	2 m^2	1	Minor
Intentional Breach	2 m^2	3	Moderate
Intentional Breach	12 m^2	1	Severe[d]
Intentional Breach	5 m^2	2	Severe
Intentional Spill	Premature offloading of LNG	None	Moderate-Severe

Notes: a - Assumes vessels remain joined during spill event and breach is mostly plugged
b - Minor suggests ship can be moved and unloaded safely
c – Moderate suggests damage that might impact vessel and cargo integrity
d – Severe suggests significant structural damage. Ship might not be able to be moved without significant difficulty and includes potential for cascading damage to other tanks

As discussed in Appendix B, the intentional breaching events considered included attacks, sabotage, hijackings, and insider threats. Each threat is a different type and would cause spills of different sizes and in different locations. This was taken into account when assessing what parts of an LNG ship would encounter spilled LNG and the extent and duration of the contact, discussed in detail in [Hightower 2004].

Table 40 shows that, for accidental and many intentional breaching events, the cryogenic damage to the LNG vessel would probably be minor to moderate. Moderate damage, however, might impact vessel and cargo integrity; therefore, pre-planning of approaches to mitigate these consequences should be considered. Severe structural damage could occur from some of the very large spills caused by intentional breaches. This is because the volume and rate of the LNG spilled could significantly impact the ship’s structural steel. A cascading failure that involves damage to additional cryogenic tanks on the ship from the initial damage of one of the LNG cargo tanks is a possibility that cannot be ruled out at the present time. Determination of the probability or likelihood of such an event depends on the breach scenario, the spill location and any implementation of prevention and mitigation strategies to prevent such an event. In areas where cascading failures might be a significant issue, the use of complex, coupled, thermal, fluid, and structural analyses should be employed to accurately determine the potential for and extent of structural damage to the LNG ship and other LNG cargo tanks from various breach and spill events.

4 LNG SPILL DISPERSION AND THERMAL HAZARDS

If ignition occurs immediately upon spillage, then non-pre-mixed combustion occurs. In industrial spills, non-pre-mixed combustion is referred to as a fire, and the fuel-air mixing rate is controlled by flow turbulence. (In laboratory settings, non-pre-mixed combustion is referred to as a diffusion flame, because mixing is controlled by diffusive processes.) Specifically for LNG spills, the fire would be referred to as a 'spill' or 'pool' fire, as the liquid spilling from the ship results in a quasi-steady-state fire. The hazard from this type of combustion is thermal, primarily driven by radiating heat flux. Other types of non-pre-mixed combustion, including jet and spray flames, are not relevant to LNG spills, due to LNG's low storage pressure and low boiling point.

If mixing occurs before ignition, then the resulting combustion is pre-mixed. In industrial accident settings, two forms of pre-mixed combustion can occur, depending upon the strength of the ignition source and geometric factors. The two forms are termed *deflagration* and *detonation*. Deflagration is the most likely mode to occur. Because the fuel is pre-mixed with air, the flames spread at a rate relative to the chemical mixture (flame speed) and the rate at which turbulent mixing can enhance the flame area. Deflagrations differ in their consequences, depending on whether they occur in confined or unconfined volumes.

In large open areas, the hot combustion products are buoyant and will entrain the air into the fuel mixture. The result is known as a fireball. In enclosed volumes, the combustion will result in pressure generation due to confinement of the volume expansion of the hot gases. The result is usually the failure of the enclosure. These events are loosely termed explosions. Propane leaks in houses are a typical example.

If ignition occurs sometime during mixing, not before mixing takes place and not at the end when the fuel is completely mixed, then a mixture of combustion modes will result. Generally, a pre-mixed combustion event will occur first, followed by a non-pre-mixed combustion event; and pre-mixed combustion occurs faster than most mixing events. Thus, upon ignition, a pre-mixed flame will propagate from the ignition source to the spill location. This phenomenon is known as a flashback. It can generate high pressures or result in a slow burn or fireball. The flame will anchor on the spill source and a fire will result at the spill source for the duration of the spill.

The distance and thermal damage to structures from a range of different spills was calculated based on the following selection of nominal spill conditions.

Condition 1: Spill Calculations Drainage From A Non-Pressurized Tank With A Single Hole

Note that, for all calculations, a tank with volume of 25,000 m^3 could be expected to spill approximately 12,500 m^3. An initial liquid height in the tank above the breach of 15 m and a density of 450 kg/m^3 for LNG were used.

Nomenclature:

A_t – Cross sectional area of tank
A_o - Cross sectional area of hole
m – mass of liquid in tank
ν – velocity
ν_o – effective velocity out of hole
h_t – height of the top surface of the liquid
h_i – initial height of fluid
C_d – discharge coefficient
V – volume of liquid

Basic Equations:
First apply continuity equation where:

$$\frac{dm}{dt} = (\rho A v)_{in} - (\rho A v)_{out}$$
$$(\rho A v)_{in} = 0, \ \ thus$$
$$\frac{dm}{dt} = -(\rho A v)_{out} \tag{1}$$

Mass, m, can be expressed as ρV, and then V = A_th. Substitute into eq. (1):

$$\frac{d(\rho A_t h)}{dt} = -(\rho A v)_{out} \tag{2}$$

The velocity of the fluid coming out of the tank can be expressed as a function of height through invoking Bernoulli's equation.

$$\frac{1}{2}\rho v_t^{\,2} + p_t + \rho g h_t = \frac{1}{2}\rho v_o^{\,2} + p_o + \rho g h_o$$
$$\rho g h_t = \frac{1}{2}\rho v_o^{\,2}$$
$$v_o = \sqrt{2 g h_t}$$

Multiply by a discharge coefficient to account for resistance of the hole:

$$v_o = C_d \sqrt{2 g h_t} \tag{3}$$

Total time of discharge:

Substitute eq. (3) into eq. (2) and integrate with initial condition, t = 0, h=h_i.

$t = \sqrt{\frac{2}{g}} \frac{A_t}{C_d A_o}\left(\sqrt{h_i} - \sqrt{h}\right)$, then the height of liquid throughout time can be determined.

Total time to drain is:

$$t = \sqrt{\frac{2}{g}} \frac{A_t}{C_d A_o}\left(\sqrt{h_i}\right)$$

Average flow rate:

The flow rate will be greatest at the beginning of the spill, due to the hydrostatic head having a maximum. The flow rate has a linear dependence on time, so an average flow rate was determined by dividing the maximum flow rate by 2. The maximum flow rate can be found by substituting eq. (3) into eq. (1), and using m= ρV to express in terms of volume/time. Then,

$$\left(\frac{dV}{dt}\right)_{average} = \frac{-\left(Av\right)_{out}}{2} = -\frac{C_d A_o}{2}\sqrt{2gh_i} \qquad (4)$$

Equation 4 was used for the calculations to determine the average flow rate out of the tank.

Condition 2: Spreading Equation

The diameter of the spill was determined by assuming a steady state where the mass coming in is balanced by the mass going out, due to the heat flux from the heating of the water below and from the fire above, denoted by ν_{total}. Thus,

$$\left(\rho A v\right)_{in} = \left(\rho A v\right)_{out}$$

$$\left(\frac{dV}{dt}\right)_{average} = \left(Av\right)_{out} = \frac{\pi D^2}{4} v_{total}$$

$$D = \sqrt{\frac{4}{\pi v_{total}}\left(\frac{dV}{dt}\right)_{average}} \qquad (5)$$

Equation (5) was used to determine the diameter of the spill.

Condition 3: Distance To A Specified Radiative Flux Level after Fire Ignition

Nomenclature:

q'' - radiative flux incident upon an object
E_p – Average surface emissive power (kW/m^2)
F – view factor
τ - transmissivity

A right cylinder, solid flame model was used to model the pool fire. The effect of wind on the flame was considered negligible.

The Moorehouse correlation for LNG was used to calculate flame height, found on page 3-204 of the SFPE handbook, Fire Protection Engineering, 2nd ed., (1995). The term u^* is a non-dimensional wind velocity taken to be 1 for low wind speeds.

$$\boldsymbol{H} = 6.2\,\boldsymbol{D}\left[\dot{\boldsymbol{m}}'' / \rho_a \sqrt{\boldsymbol{gD}}\right]^{0.254} \boldsymbol{u}^{*-0.044} \tag{6}$$

The radiative flux incident upon an object can be determined by:

$$\boldsymbol{q}'' = \boldsymbol{E}_p \tau \boldsymbol{F} \tag{7}$$

In order to determine distance to a specified, $\boldsymbol{q}''$, Fig. 3-11.13 on page 3-210 of the SFPE handbook was used. The figure gives the non-dimensional distance from the flame axis as a function of view factor and fire height-to-radius ratio. Because $\boldsymbol{q}''$, E_p, and τ are specified, F can be determined by eq. (7), and height-to-radius ratio from eq. (6). Then the thermal hazard distance can be determined from the figure.

Using the nominal conditions, an analysis was performed that looked at the potential ranges of spill and fire conditions available from experimental literature. Example results of this sensitivity analysis are presented in the table below.

Table 41: Sensitivity Analysis of Thermal Intensity Level Distances

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m
ACCIDENTAL EVENTS								
1	1	.6	$3X10^{-4}$	220	148	40	177	554
2	1	.6	$3X10^{-4}$	220	209	20	250	784
INTENTIONAL EVENTS								
2	3	.6	3×10^{-4}	220	209	20	250	784
5	3	.6	3×10^{-4}	220	572	8.1	630	2118
5*	1	.6	3×10^{-4}	220	330	8.1	391	1305
5	1	.9	3×10^{-4}	220	405	5.4	478	1579
5	1	.6	2×10^{-4}	220	395	8.1	454	1538
5	1	.6	3×10^{-4}	350	330	8.1	529	1652
10	1	.6	3×10^{-4}	220	467	4.1	549	1823

*nominal case

The results in Table 41 suggest that, for most of the credible accidental breach and spill scenarios, the general distance for major structural damage (high hazards where the thermal intensity is about 37.5 kW/m^2) can occur, on average, up to 250 m from a spill. The results also suggest that, for most of the credible intentional breach and spill scenarios, the general distance for major structural damage (high hazards) can occur, on average, up to 500 m from a spill. In general, the distance to low thermal hazard levels, about 5 kW/m^2 is about 600-750 m for accidental spills and approximately 1600 m for intentional spills. For a very large, cascading spill, high hazard zones could approach 2000 m. These results were used to help quantify the hazard zone identification and hazard level identification for various breach and spill events.

Consideration of Mass Fires and Pool Fires

All of the LNG fire studies reviewed assume that a single, coherent pool fire can be maintained for very large pool diameters (>100m). This might be unlikely due to the inability of air to get into the interior of the fire and support combustion. At some very large size, the flame envelope would break up into multiple flamelets. The heights of these flamelets are much less than the fuel bed diameter [Zukoski, Corlett, Cox and Chitty]. The break up into flamelets would result in a much shorter flame height than that assumed by the reviewed studies, which are applying height correlations far out of the diameter range for which they were developed. It is expected that the L/D (height/pool diameter) would probably be much smaller than that predicted by existing correlations.

The correlations predict an L/D ratio between one and two, while a more realistic ratio for a mass fire would be under 0.5. The view factor is very sensitive to flame height at distances not close to the fire (>1 pool diameter). View factors are used to determine how much radiative flux an object receives. Thus, if a more realistic flame height is used, lower than that which is typically calculated, then the amount of heat flux that an object receives would be less, thereby decreasing the thermal hazard zone. The zone could be decreased by a factor of two to three, depending upon the damaging heat flux levels of interest.

Various correlations for flame height have been developed for a range of pool diameters up to 30 m. The L/D correlations are typically expressed in terms of a non-dimensional heat release rate: $\dot{Q}*$. The following figure is from Zukoski, which shows how the ratio of flame height to pool diameter varies with $\dot{Q}*$. As pool diameter increases, $\dot{Q}*$ decreases because it is proportional to $1/\sqrt{D}$. Zukoski states that there are different transition regions that occur, demarked by I – V in Figure 13.

For very large pool fires, region II, the flame breaks up into a number of independent flamelets as $\dot{Q}*$ decreases, and the flame height depends on the diameter and the heat release rate. For region I, the height of the flamelets appears to become roughly independent of the source-diameter and depends only on the local heat release rate per unit area (or fuel flow per unit area). This figure is based upon pool fire tests where fuel vaporization is not affected by a substrate (such as water); water; therefore, this curve should not be used for the determination of when a pool breaks up into flamelets for LNG pool fires on water. It is unknown what the limiting diameter for break up is for LNG pool fires on water. Using an estimate of approximately 100 m, the distance to the high and lower level hazards was calculated for a range of spill conditions and is presented in Table 46.

The pool diameter and flame height suggested are speculative because experiments for large pool fires have yet to be performed. Many researchers have provided flame height correlations based on pool fires much smaller than those presently being considered [Heskestad 1998]. These results suggest LNG pool fires of as much as 8900 m in diameter before breakup, based on results of laboratory testing on approximately 7 m by 7m wood fiberboards. Whether their results can be extrapolated to very large pool fires remains to be determined.

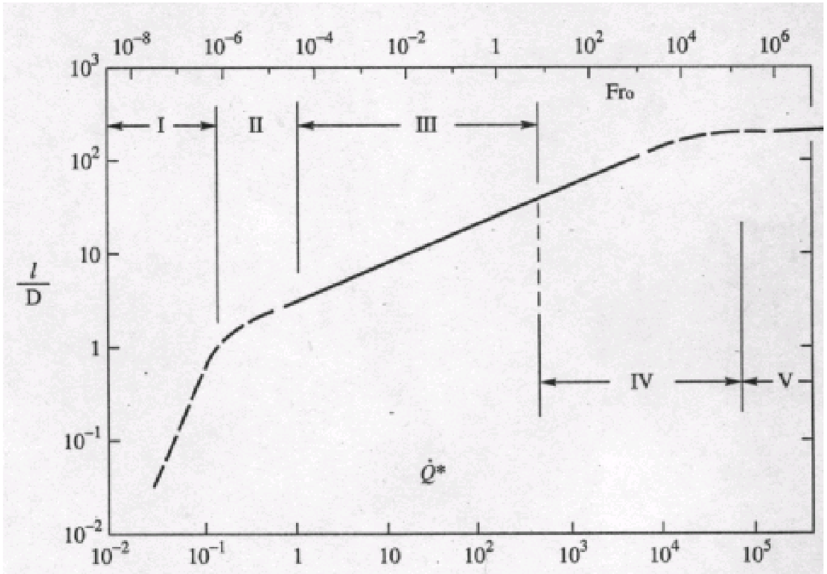


Figure 13. Flame Height/Diameter Ratio vs. Dimensionless Heat Release Rate

Taken from: [Zukoski, 1995]

The following calculations in Table 42 show the differences in the thermal hazard distances obtained using an assumption of a single, coherent pool fire for very large diameters versus the assumption of several mass fires (flamelets) with maximum diameters on the order of 100 m. A solid flame model that accounts for view factors and transmissivity and the Moorhouse correlation for flame height to diameter was used. A low wind condition was assumed; therefore, flame tilt and drag were not required. A surface emissive power of 220 kW/m^2, a transmissivity value of 0.8, and a burn rate of 3 x 10^{-4} were used. The results indicate that there is a significant increase in the distance to 5 kW/m^2 when a single coherent pool fire is assumed. The thermal hazard distances from a mass fire (flamelets), which is physically more realistic for large spills, should be considered in evaluating thermal hazards from potential large spills.

Table 42: Thermal Hazard Distance - Single Pool Fire vs. Mass Fire Assumptions

ASSUMPTION	DIAMETER	FLAME HEIGHT (m)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
Mass Fire (flamelets)	100 m each (multiple fires comprising area of 500 m dia.)	148	400	1000
Single Pool Fire	500 m	604	575	1800

Furthermore, studies discussed in Appendix C note that the missive power decreases with increasing fire size due to smoke shielding. Values significantly lower than 220KW/m^2 are possible. As improved data are collected, improvements in hazard analysis can be implemented. Other phenomena, such as the occurrence of fire whirls, may increase the hazard by generating large columnar flames with high emissive power. These structures most often form during non circular pool shapes exposed to light winds and rarely last more than a few seconds.

LNG Dispersion

In most of the scenarios identified, the thermal hazards from a spill are expected to manifest as a pool fire, based on the high probability that an ignition source will be available from most of the events identified. In some instances, such as an intentional spill without a tank breach, an immediate ignition source might not be available and the spilled LNG could, therefore, disperse as a vapor cloud. For large spills, the vapor cloud could extend to as much as 1600 m or more, depending on spill location and site atmospheric conditions. In congested or highly populated areas, an ignition source would be likely, as opposed to remote areas, in which an ignition source might be less likely.

If ignited close to the spill, the thermal loading from the vapor cloud ignition might not be significantly different from a pool fire, because the ignited vapor cloud would probably burn back to the source of liquid LNG and transition into a pool fire. If the cloud is ignited at a significant distance from the spill, the thermal hazard zones can be extended significantly. The thermal radiation from the ignition of a vapor cloud can be very high within the ignited cloud and, therefore, particularly hazardous to people.

Experimental data and analytical estimates for vapor spreading suggest that a large vapor plume could extend to large distances, depending on atmospheric conditions. Therefore, while the impact from a vapor cloud dispersion and ignition from a large spill can potentially extend beyond 1600 meters, the area of high impact might be reduced. This suggests that LNG vapor dispersion analysis should be conducted using site-specific atmospheric conditions, location topography, and ship operations to adequately assess the potential areas and levels of hazards to public safety and property, and consideration of risk mitigation measures, such as development of approaches and procedures to ignite a dispersion cloud quickly if conditions exist that the cloud would impact critical areas.

To assess the extent of the potential dispersion from an LNG spill, we used VULCAN, a validated CFD model [Tieszen, et al. 1996]. The VULCAN fire field model under development at Sandia National Laboratories was derived from the KAMELEON Fire model in collaboration with SINTEF and Computational Industry Technologies, AS (Norway). VULCAN was developed for liquid and gaseous hydrocarbon fuels. The model has been used for a large number of heavy hydrocarbon fuel fires. VULCAN uses a Cartesian based geometry. The code runs on single or multi-processor machines. It generally parallelizes best on six processors. It runs under LINUX and UNIX operating systems.

VULCAN is a validated CFD fire model that uses a standard RANS formulation of the equations of motion, where the turbulence is averaged across all time scales using a k-ε turbulence model. A buoyant, vorticity generation sub-model of turbulence is included for turbulence length scales below the scale of the grid. VULCAN uses Magnussen's Eddy Dissipation Concept combustion model to relate mechanistically the local fuel, oxygen, energy, and turbulence levels to consumption of species. Soot is modeled using Magnussen's soot model to describe mechanistically the soot formation and destruction process.

VULCAN uses Leckner's model for gas band radiation. The transport of thermal radiation is calculated using the Discrete Transfer Method of Shah to solve the radiative transport equation.

Either the evaporation of a liquid pool is modeled using a user-specified evaporation rate, or by allowing the code to calculate its own evaporation rate based on heat transfer into the fuel pool. VULCAN also has a rudimentary liquid spreading model based on lubrication theory. This model predicts spreading of fuel on a horizontal surface, and is capable of modeling the dripping/draining of fuel vertically (e.g., from floor to floor in a building).

In order to obtain LNG dispersion distances to LFL for accidental events, a low wind speed and highly stable atmospheric condition were chosen because this has shown to result in the greatest distances to LFL from experiment, and thus should be the most conservative. A wind speed of 2.33 m/s at 10 m above ground and an F stability class were used for these simulations. The time it took for LFL to be reached was approximately 20 min. for each calculation. Two cases were analyzed, one for the nominal case of a 5 m^2 hole and one tank breach, and the other for a 5 m^2 hole and three tanks breached at once. This last case is the largest expected spill; hence, it should give an upper bound of the LFL for vapor dispersion for intentional events. The results are summarized in the table below.

Table 43: Dispersion Distances to LFL for Potential Spills

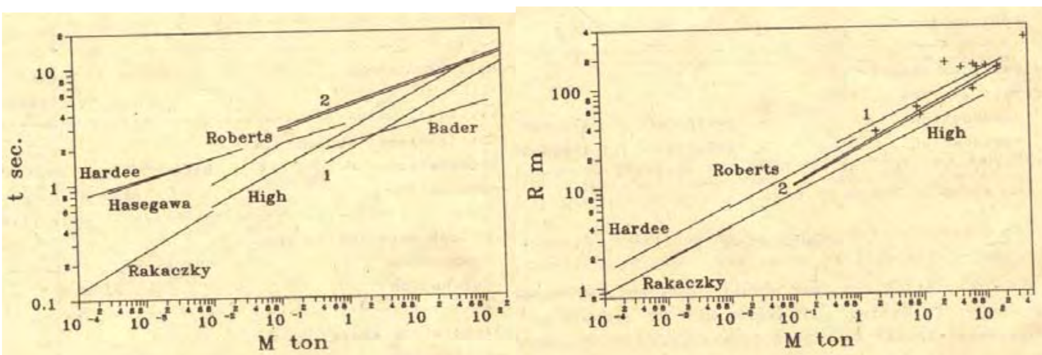
HOLE SIZE (m^2)	TANKS BREACHED	POOL DIAMETER (m)	SPILL DURATION (min)	DISTANCE TO LFL (m)
Accidental Events				
1	1	148	40	1536
2	1	209	20	1710
Intentional Events				
5	1	330	8.1	2450
5	3	572	8.1	3614

As noted above, the chances of a large vapor dispersion from either an accidental or intentional breach is rather unlikely because of the high probability that an ignition source will be available for most of the events identified. Although, the significant distances though of potential vapor dispersion, especially for a large intentional breach, suggest that LNG vapor dispersion analysis and risk mitigation measures should be carefully considered. Location-specific environmental conditions should be carefully evaluated and appropriate safety measures implemented to ensure that public health and safety, and critical facilities and infrastructures, are adequately protected.

4.1 Fireballs Resulting from an LNG Spill

A fireball will result from an LNG spill only if some mixing of the fuel and air occurs prior to ignition. Thus, if ignition occurs immediately upon release, no fireball will result. For a fireball to occur there must be fuel release, spread, vaporization, and ignition after significant premixing. If all these events have occurred, a fireball is the most benign form of combustion that can result. The hazards are principally short-time thermal damage high in the air and away from structures and people.

Large-scale fuel-air fireballs and explosions were studied in Russia in the late 1980's [Dorofeev et al. 1991]. In their study, fireballs were created from the dispersal of 0.1 to 100 metric tons of hydrocarbon fuels (gasoline, kerosene, and diesel fuel). Because the fuels used in the experiments have significantly lower vapor pressure than LNG, mixing was created by explosively dispersing and igniting the mixture in a fuel-rich state. In spite of these differences, the results are directly relevant to fireballs that might result from a delayed ignition of vaporized LNG.



(a) (b)

Figure 14. Fireball Duration and Radius as a Function of Fuel Mass

[Dorefeev et. al. 1991]

Figure 14 shows the duration (in seconds) of combustion within the rising fireball and the maximum radius (in meters) of the fireball as a function of the fuel mass (in metric tons; i.e., per 1000kg). For example, a fireball from a 100-ton fuel release is about 11 seconds duration and has a radius of about 115 meters. Also shown in Figure 13 are the results of earlier studies, providing a measure of the uncertainty in the available data. Dorofeev fit the data to a curve and provided the following correlations:

The duration of the fireball from combusting clouds is given as

$$t = 4.6M^{0.2}$$

in which the fuel mass, M, is in metric tons and the time, t, is given in seconds.

Similarly, the maximum radius of the fireball is given as:

$$R = 23M^{0.35}$$

in which the fuel mass, M, is in metric tons and the radius, R, is given in meters.

The thermal flux from the fireballs was also measured. Peak fluxes for combusting gasoline were in the 150 – 330 kW/m^2 range. LNG would be expected to have similar behavior.

These flux levels are of the same order of magnitude as those from a pool fire. Unlike a pool fire, however, the fireball is of short duration (in the order of seconds to tens of seconds), depending upon the mass of fuel in the air. The fireball will entrain and burn all flammable vapors and provide an ignition source to the underlying liquid spill. The overall threat from a fireball is typically not of primary concern if a long duration pool fire follows it.

4.2 Thermal Damage on Structures

The potential for damage to other vessels or structures from an LNG spill and fire needs to be considered to determine the overall risk. As noted in Appendix C, the potential for fire damage from spills can be relatively extensive. The six spills projected in Appendix B would take anywhere from 10 – 20 minutes to release up to 50% of the LNG in an individual tank for a large spill and up to one hour for a small spill, depending on the location.

The thermal radiation that will damage structures is approximately 37 kW/m^2 for durations of more than 10 minutes. Damage can be expected to the vessel and nearby steel structures, because steel strengths are reduced to 60 – 75% of their room temperature values at 800º K. Further reduction in strength will result for temperatures above 800º K. Steel will melt at approximately 1800º K and is generally considered to have no strength at half the melt temperature, or 900º K. The calculations suggest that these temperatures could exist at a spill from an LNG cargo tank from 30 minutes to an hour and, therefore, potentially damage nearby steel and other structures.

Of even greater importance is the possibility that a large spill could cause a cascading set of LNG cargo tank failures. In this instance, significant long-term fire damage could result to a nearby steel structure, unloading terminal, or unloading platform. Positive operational and risk management measures can be taken to try to prevent these types of issues. This could include redundant or multiple offloading capabilities or moorings, fire protection systems, etc., as identified in Section 6.

4.3 Analysis of Fire Damage to LNG Cargo Tank Insulation

The insulation used in LNG ships varies considerably, from rigid foams to bulk zeolite-type materials. The susceptibility of these insulation materials to either burning or thermal degradation also varies considerably. Many LNG vessels use foam insulation materials that include polystyrene, polyurethane, phenolic resin, and hybrid foam systems. [Kawasaki 2003] [Kvaerner-Masa 2003,2004] [OTA 1977] These foams are considered combustible to slightly combustible; meaning, they will burn when exposed to an open flame, as might occur in a breach with a resulting fire. Of greater importance, though, is that these foams will begin to decompose at temperatures of about 550º K. Because an LNG fire can be expected to burn at temperatures of approximately 3000°F, thermal loading on the LNG vessel from an engulfing fire, if suffieient in duration, could lead to heat transfer through the structure, decomposition of the foam, and an increase in the LNG volatilization rate in an impacted cargo tank. This could lead to rupture or collapse of the tank, additional damage to the LNG vessel, and greater hazards to both the public and property.

Foam used to insulate LNG is enclosed within a steel weather cover, or within the inner hull of the LNG tanker. Extensive burning of the foam is not expected, given the lack of sufficient air to support combustion in these regions, even in cases with limited damage to the hull or weather cover. Based on the foam being located within an enclosure, thermal decomposition of the LNG foam insulation is more likely. Heat transfer will result in thermal decomposition of the foam insulation, the products of which will burn if vented to the air, or cause an increase in the pressure in the region between the steel and the inner container.

From the spills calculated and discussed in this section, accidental spills with general pool fire diameters of 200 m might be possible. The flame height for such a spill might approach 150 m, high enough to engulf the top of an LNG tanker. For this size of fire, at least some portions of adjacent LNG cargo tanks would probably be exposed to the fire. As calculated in other sections of the report, a fire from a spill could last from five to twenty minutes.

We estimated the consequence of a fire from an LNG spill on the insulation of an undamaged LNG cargo tank. Initial modeling of the thermal response and decomposition of 12 lb per cubic foot density polyurethane foam in above-deck areas was conducted using one-dimensional heat transfer models and polyurethane foam thermal degradation data. The above deck location was chosen as a severe condition, due to the presence of only a single, steel cover and air gap protecting the foam insulation. The calculations were conducted with a tank configuration of a steel cover and air gap overlaying eight inches of foam insulation over an aluminum LNG cargo tank. Using a thermal radiation intensity of 220 kW/m^2 for the fire, as observed from several LNG fire tests, the analysis suggests that heat transfer through the steel shell and air gap could fully degrade eight inches of polyurethane type foam in about five minutes. The maximum volumetric production of LNG vapor calculated in the LNG cargo tank was about 0.8 m^3/s per square meter of tank wall exposed to the fire.

For several reasons, the analysis probably provides a lower bound for the time required for a fire from an LNG spill to degrade the thermal insulation of an adjacent cargo container. First, the analysis did not take into consideration the thermal retardation benefits of the fire suppression systems on LNG cargo tankers, which can provide up to 10 $liters/m^2$ per minute of water to exposed cargo tanks and decks, as established by the International Gas Carrier Code. Second, many LNG carrier designs have up to 36 inches of thermal insulation, which probably increases the time for damage to occur to an adjacent LNG cargo tank. Third, the thermal decomposition rate and decomposition temperature of insulating foams differ, depending on the foam material and properties. These additional factors all could increase the time required for full thermal degradation of the insulating foam on an adjacent LNG cargo tank.

The results, though, do suggest that damage to adjacent containers from an LNG spill and fire cannot be ruled out and should be carefully considered, especially in operations in high-consequence areas. Based on our analysis, it appears that one to two adjacent LNG cargo tanks might be affected at any one time from an LNG spill and fire. Efforts to manage the hazards from the impact of an LNG fire on adjacent cargo tanks should consider a combination of risk management approaches. These should include consideration of LNG cargo vessel designs, consideration of the designs of LNG cargo tank insulation and thermal degradation properties, consideration of operations and safety management improvements or upgrades, and consideration of both public safety and property consequences for site-specific locations. These efforts, when implemented as a system, could produce an integrated protection and risk management approach that provides an appropriate level of both public safety and property and reduces potential damages from a fire.

5 LNG – AIR COMBUSTION TO GENERATE DAMAGING PRESSURE

Two types of combustion modes might produce damaging pressure, deflagration, and detonation. Deflagration is a rapid combustion that progresses through unburned fuel-air mixture at subsonic velocities, whereas detonation is an extremely rapid combustion that progresses through an unburned fuel-air mixture at supersonic velocities.

In order for deflagration to occur, the fuel-air concentration must be above the minimum flammable limit (lean limit) and below the maximum flammable limit (rich limit). For LNG, these limits are 3.8% – 17% fuel by volume. If the fuel concentration is within these limits and encounters an ignition source, it will ignite and burn. Because of the moderate flammability range, the amount of time lapse between dispersal and ignition is limited. For low reactivity fuels such as natural gas, combustion will usually progress at low velocities and not generate overpressure. Certain conditions, however, might cause an increase in burn rate that does result in overpressure. If the fuel-air cloud is confined, is very turbulent, or progresses through obstacles, a rapid acceleration in burn rate might occur [Benedick et al. 1987]. In extreme cases, the burn rate might increase to supersonic velocities. This is known as deflagration-to-detonation transition (DDT).

Under specialized conditions, pre-mixed combustion can result in a detonation. This mode is not common and is generally considered to be very unlikely (but not impossible) to occur in most industrial accident situations, such as an LNG spill. Detonations have the highest power density of any combustion mode and, thus, result in the highest pressures and most damage. In a detonation, the combustion front typically travels at Mach 5 and, for hydrocarbons, has a peak pressure about 15 times the initial pressure. A detonation can be directly initiated in a fuel and air mixture from high initiation pressures or, under very limited circumstances, it can transition from a deflagration to a detonation (called DDT, or deflagration to detonation transition in the pre-mixed combustion literature) under conditions involving confinement. In industrial accidents, detonations are also sometimes called 'unconfined vapor cloud explosions.' In military literature, gas phase detonations are termed fuel-air explosions (FAE).

Detonation is the most violent form of fuel-air combustion. For detonation to occur, the fuel-air mixture must be within the minimum and maximum detonation limits. These limits are much narrower than flammability limits. To ignite a fuel-air mixture within the limits of detonation, shock initiation is necessary. Shock initiation can be produced by "igniting" the fuel-air cloud with an explosion or by the deflagration-to-detonation transition involving confinement described above.

For low reactivity fuels, the initiation energies are quite large and unlikely to occur in an accidental breach, but might be possible in an intentional breach or tank rupture scenario. Spilled LNG could become trapped between the inner and outer hulls which, if ignited, could lead to an explosion. In general, large releases will involve sufficient LNG for this space to be fuel rich. Of greater concern are small leaks where a flammable mixture could develop.

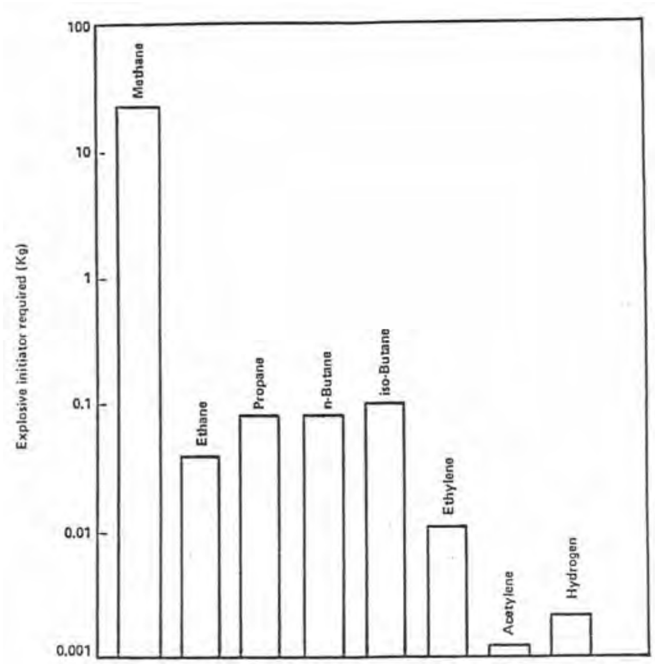


Figure 15. Relative Detonation Properties of Common Fuels

[Benedick et al 1986]

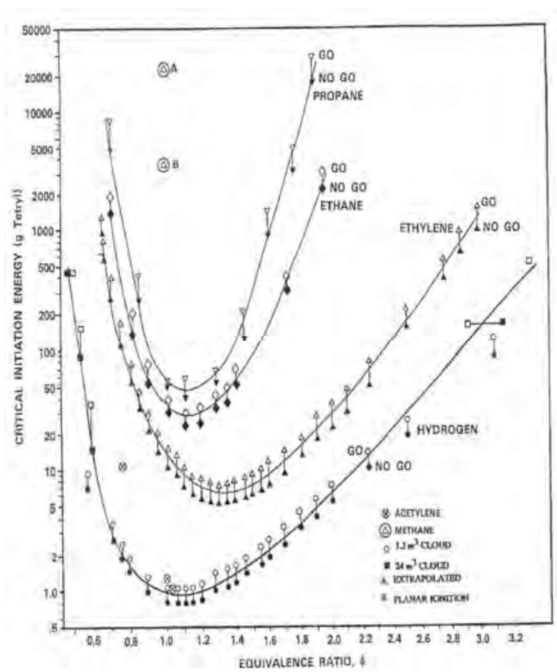


Figure 16. Initiation Energy Required to Detonate Common Fuels at Various Fuel-Air Ratios.

[Moen 1993]

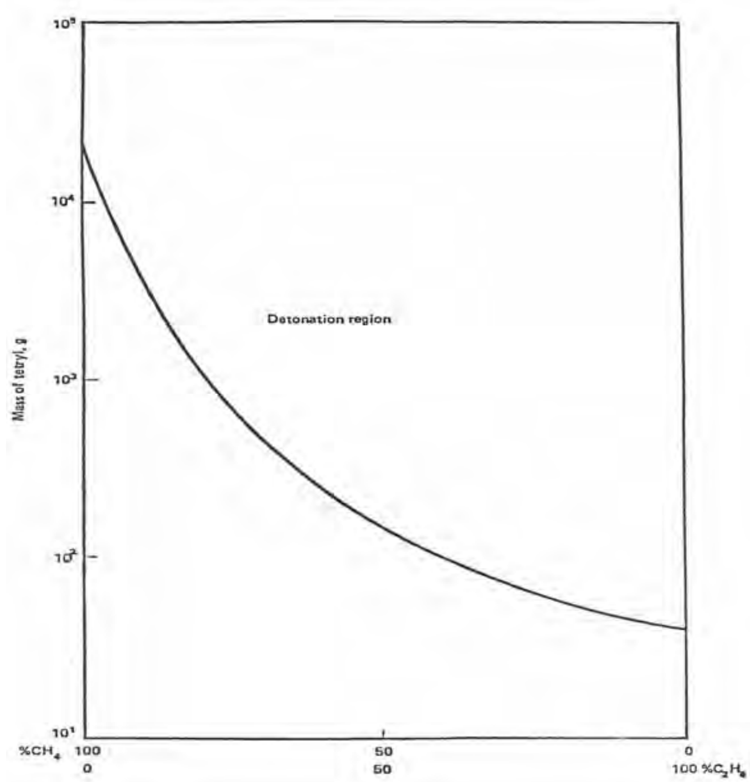


Figure 17. Effect of Ethane Concentration on the Detonability of Methane

[Moen 1993]

Another potential for an explosion is if LNG is spilled without an ignition source, such as an intentional spill from premature offloading of LNG. In this scenario, there could be extensive volumes of LNG that can be spilled either onto the ship or onto the water surface without and ignition source. These type of approaches have been considered and used and are very sensitive to environmental and meteorological conditions [Tieszen 1991]. Therefore, the potential for this type of event exists, but actually getting an explosion can be difficult.

Figures 16 – 17 show the relative detonation properties of several common fuels; and Table 44 provides some physical and chemical properties of hydrocarbon fuels. As Figure 15 shows, methane does not detonate as readily as other hydrocarbons, making it a safer fuel. Further, all fuels become less able to detonate if they are not perfectly mixed to stoichiometric proportions, as shown in Figure 16. It is unlikely for this correct stoichiometric proportion to be obtained around or in a ship during a cryogenic liquid spill. For many sources, refined LNG has a high percentage of methane at the wellhead compared to natural gas. Figure 17 shows that the level of refinement of natural gas stored as LNG can have an effect on detonation sensitivity, with a less processed product being more sensitive to detonation.

Table 44: Properties of Common Hydrocarbon Fuels

[AICE 1994] [Baker 1991]

FUEL	FORMULA	FLAMMABLE LIMITS, VOL %	HEAT OF COMBUSTION, kJ/g	IGNITION TEMP, °C	BOILING POINT, °C
Methane	CH_4	5.5 – 14	55.5	650	-161
Ethane	C_2H_6	3 – 12.5	51.9	472	-89
Ethylene	C_2H_4	2.7 – 36	50.3	490	-104
Acetylene	C_2H_2	2.5 – 82	49.9	305	-84
Propane	C_3H_8	2.2 – 9.5	50.3	450	-42
Propylene	C_3H_6	2.4 – 10.1	48.9	455	-48
Propyne	C_3H_4	2.1 – 12.5	48.3	NA	-23
Octane	C_8H_{18}	1 – 6.5	47.9	NA	126

5.1 Magnitude of LNG-Air Explosion Overpressure

In order to estimate the overpressure at a given distance from a fuel-air explosion, several parameters must be defined. First, the mass of fuel within the flammability limits must be determined. To find the energy released, the mass of fuel within flammability limits is then multiplied by the heat of combustion. Finally, the velocity of combustion, or flame Mach number (Mf), must be estimated. For explosively initiated detonations, a value of 5.2 should be used for Mf.

Once the total energy release and combustion velocity are known, the scaled overpressure versus scaled distance curve given in Figure 18 can be used to estimate an overpressure at a specific distance. Within Figure 18, the curve assumes a spherical cloud geometry and single point initiation. This is not quite accurate for LNG vapor clouds, which are more disk shaped.

Most structures are significantly less resistant to internal blasts than they are to external blasts. If natural gas finds it way into a structure and then ignites, severe structural damage can occur. This is a potential concern to the LNG tanker if the spilled LNG is somehow trapped on the ship or between the hulls, as well as for nearby structures or other ships where the LNG might settle and ignite. While detonations are unlikely, some type of overpressure events could occur on a ship with a large LNG spill and provisions to prevent these types of events should be considered.

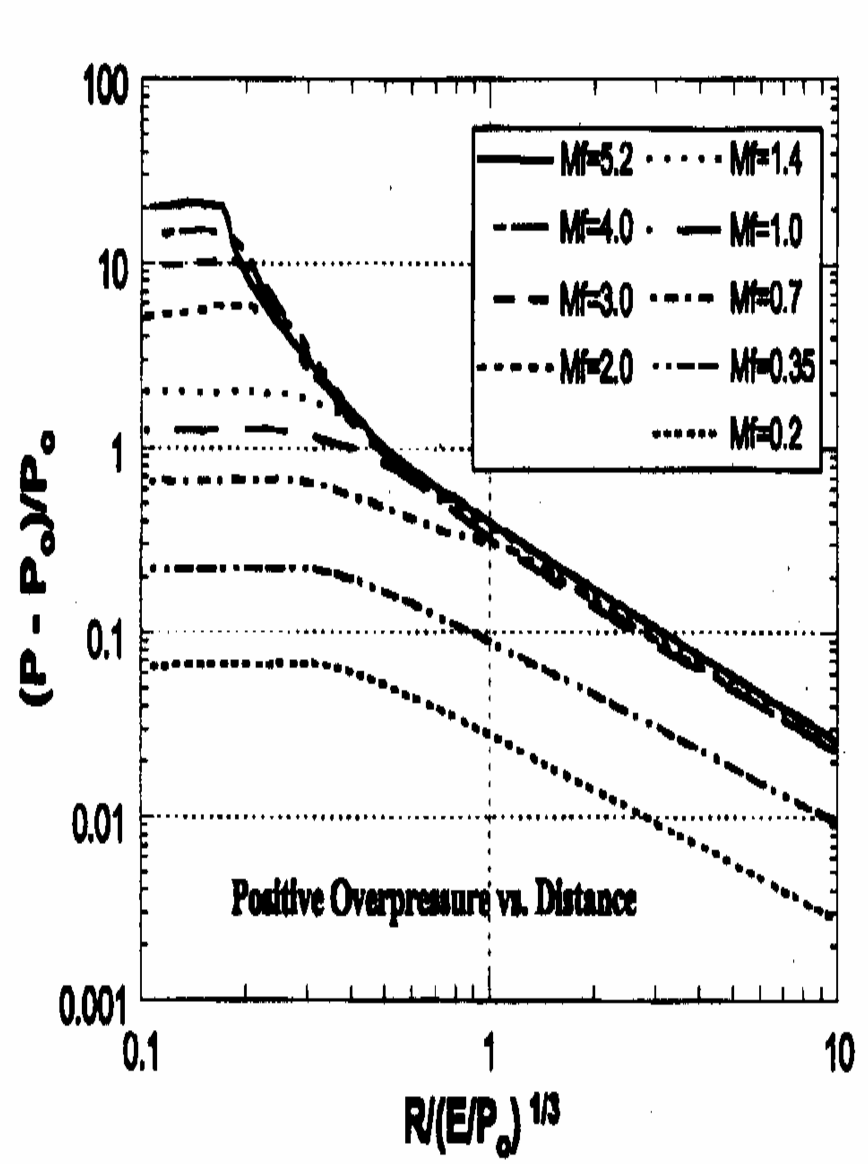


Figure 18. Scaled Blast Overpressure vs. Scaled Distance For Various Flame Mach Numbers

P = Blast overpressure, Pa
P_0 = Ambient pressure, Pa
R = Distance from explosion center, m
E = Energy released from explosion, J

[Tang 1999]

APPENDIX E
LNG PLANT EXPLOSION IN SKIKDA, ALGERIA

REPORT OF THE U.S. GOVERNMENT TEAM SITE INSPECTION OF THE SONATRACH SKIKDA LNG PLANT IN SKIKDA, ALGERIA
MARCH 12-16, 2004

EXECUTIVE SUMMARY (only)

On March 12 – 16, 2004 a six-member DOE and FERC team (U.S.G. team) visited Algeria to gain an understanding of the tragic explosion and fire at the Skikda LNG facility, which occurred on January 19, 2004.

The investigation team of the U.S. Department of Energy visited Algeria at the request of the U.S. Department of Energy and with the agreement of the Algerian Minister of Energy and Mines. A Ministry representative escorted the team to Skikda to tour the damaged facility and meet with plant management and technical staff. After returning to Algiers, the U.S.G. team met with Sonatrach Executive Vice President for Downstream Activities, Bachir Achour, who gave a broader understanding of the accident and the ongoing investigations.

Several accident investigations are ongoing. The Algerian investigation is under way, and definitive conclusions are not yet available; however, on 3/22/2004, Mr. Achour presented Sonatrach's preliminary findings at the LNG 14 conference held in Doha, Qatar. The re-insurers, including Lloyds, are also carrying out an independent investigation, and findings are not yet available.

The Skikda LNG Facility was composed of six trains; trains 40, 30, 20, and 10 are adjacent, from west to east, and are separated from trains 5 and 6, which are located remotely to the east. At the time of the accident, train 10 had been shut down for major maintenance while train 6 was shut down for regular maintenance. At the time of the accident, Train 40 had been operating at steady state for six days following routine maintenance.

A series of cascading events appear to have caused a major explosion and fire that resulted in loss of life and extensive damage. Sonatrach's preliminary hypothesis is that an undetermined hydrocarbon leak occurred in the semi-confined area between train 40's control room, boiler, and the liquefaction area. Sonatrach stated that the source of this original leak is not clear and might never be determined. The air intake to the boiler's firebox apparently ingested the fuel-air mix, causing more heat to be generated within the boiler and hence raising the internal pressure. After the boiler's pressure relief valve activated, and the operators apparently turned off the supply fuel to the boiler, the air intake fan ingested hydrocarbon/air mixture within the flammable limits. The first small explosion appears to have been in the firebox enclosure. It then breached the boiler and provided an ignition source to the external accumulation of combustible gas leading to the larger explosion.

Deaths and injuries occurred only in the plant area. Damage outside the industrial area was limited to broken windows. Most deaths and injuries were due to the impact of the major explosion and flying debris, rather than from the resulting fire. The proximity of the train 40 control room to administrative, maintenance and security/fire control buildings was a major factor in the number of injuries and fatalities.

Trains 40, 30, and 20 are virtually destroyed, although damage decreases with distance from the region between trains 30 and 40 (i.e. damage to 20 is not as severe as 40). Train 10's apparent damage was minimal (loss of aluminum insulation jacket on some process vessels), and it might be usable after further inspection. Trains 5 and 6 were not impacted except for sensitive instrumentation and detectors that must be replaced prior to resuming operation (estimated by Sonatrach to be two months). The instrumentation and electrical network on train 10 might also need to be replaced and/or rewired, as it was part of the network of instrumentation feeding data to the control room for trains 10, 20, and 30.

The U.S.G. team observations and analysis of the potential events at the plant are included in this report, as well as issues to be alert to in other plant designs and operating practices.

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Exhibit 8

UNDERSTANDING THE STOLL CURVE

Introduction

Alice Stoll and Maria Chianta conducted burn injury research on “sailors, pigs and rats” in the late 1950s and early 1960s at the Aerospace Medical Research Department, Naval Air Development Center. It is reported that Sailors of the U.S. Navy volunteered to be burned on their forearms for a weekend pass. Stoll and Chianta used heat exposures on human and animal skin to determine the level of heat energy that would create a second-degree burn. For their work, they defined a second-degree burn as the point at which a blister forms which is the point at which the outer layer of human skin, the epidermis, is destroyed. The blister is formed when the epidermis separates and lifts off the remaining skin structure (the dermis). The Stoll and Chianta data was presented in a landmark paper in 1969 and was later used to create the “Stoll curve” which quantifies the level of heat and the duration of time required for a second-degree burn for a wide range of exposure conditions. The range covers a high level of heat for a short time period to a low level of heat for a much longer time period. Table 1 provides the heat exposure level (heat flux) and the exposure times that make up the Stoll curve in the context of a particular type of sensor, a copper calorimeter using an iron constantan thermocouple. Figure 1 shows the same information plotted graphically.

Table 1 Human Tissue Tolerance to Heat, Second Degree Burn A

Exposure Time	Heat Flux		Total Heat		Calorimeter [B] Equivalent		
s	kW/m^2	cal/cm^{2}s	kWs/m^2	cal/cm^2	D*T* °C	D*T* °F	DmV
1	50	1.2	50	1.20	8.9	16.0	0.46
2	31	0.73	61	1.46	10.8	19.5	0.57
3	23	0.55	69	1.65	12.2	22.0	0.63
4	19	0.45	75	1.80	13.3	24.0	0.69
5	16	0.38	80	1.90	14.1	25.3	0.72
6	14	0.34	85	2.04	15.1	27.2	0.78
7	13	0.30	88	2.10	15.5	28.0	0.80
8	11.5	0.274	92	2.19	16.2	29.2	0.83
9	10.6	0.252	95	2.27	16.8	30.2	0.86
10	9.8	0.233	98	2.33	17.3	31.1	0.89
11	9.2	0.219	101	2.41	17.8	32.1	0.92
12	8.6	0.205	103	2.46	18.2	32.8	0.94
13	8.1	0.194	106	2.52	18.7	33.6	0.97
14	7.7	0.184	108	2.58	19.1	34.3	0.99
15	7.4	0.177	111	2.66	19.7	35.4	1.02
16	7.0	0.168	113	2.69	19.8	35.8	1.03
17	6.7	0.160	114	2.72	20.2	36.3	1.04
18	6.4	0.154	116	2.77	20.6	37.0	1.06
19	6.2	0.148	118	2.81	20.8	37.5	1.08
20	6.0	0.143	120	2.86	21.2	38.1	1.10
25	5.1	0.122	128	3.05	22.6	40.7	1.17
30	4.5	0.107	134	3.21	23.8	42.8	1.23

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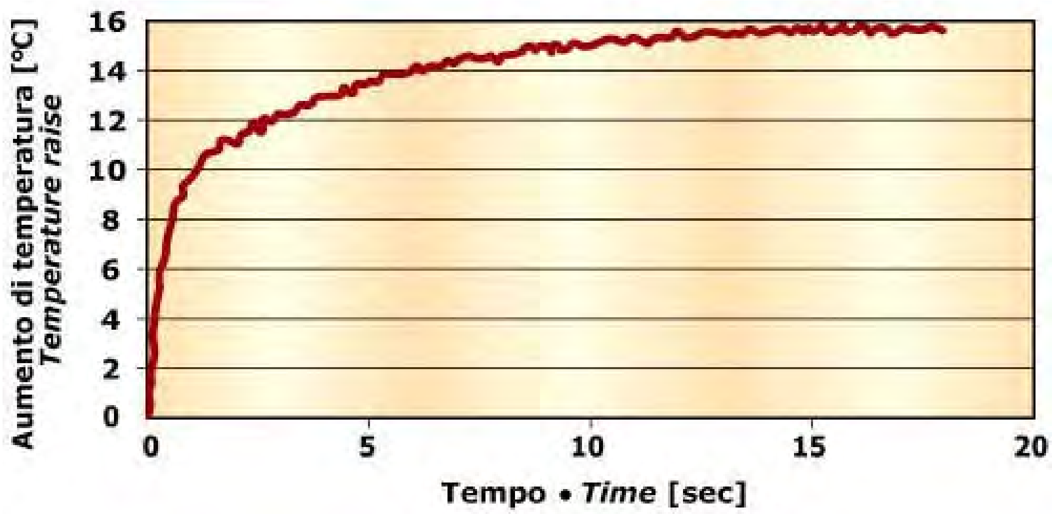


Figure 1 Stoll Curve for a copper calorimeter sensor as used in arc testing

Stoll Curve versus Skin Temperature

If the same heat exposures and times shown in Table 1 and Figure 1 were applied to human skin, the skin temperatures would be very different since human tissue is a poor conductor and copper is of course an excellent conductor. The genius of Stoll was to translate skin properties into the context of a simple and robust sensor that could be used to predict burn injury for a wide range of exposure conditions. The copper calorimeter is not intended to simulate human skin, but since its thermal properties are well known, and the thermal properties of skin are well known thanks to the work of Stoll and Chianta among others, a burn prediction can be made for human skin using date from the copper sensor.

It is also important to note that the temperatures in Table 1 and Figure 1 are delta T values or the change in temperature during the exposure time period and not the actual temperatures. For instance, if a heat flux of 1.2 cal/cm^{2}s were applied for one second we would predict a 50% probability that a burn injury would occur and we would measure a rise in temperature of 8.9 ^{O}C (16 ^{O}F) in the copper calorimeter. Since the copper would normally start at the human skin temperature or approximately 32^{O}C(89.6^{O}F), the final temperature of the copper calorimeter would be 40.9 ^{O}C (105.6^{O}F). Of course, we all know that if human skin were raised to a temperature of 105.6^{O}F in one second, no second-degree burn injury would occur.

Where is the Stoll Curve Used?

Many ASTM and NFPA standards utilize the Stoll curve to define a test method end point. These standards include the ones we are familiar with like ASTM F1959-99 Arc Test Method and F2178-02 as well as ASTM F1060 (Conductive Heat Test) and F1939 (Radiant Heat Test) and NFPA 1971 (Structural Firefighter Clothing and Equipment Standard), NFPA 1977 (Wildland Firefighter Clothing Standard) and NFPA 2112 (Industrial Flash Fire Protective Clothing Standard).

How is the Stoll Curve Used in Arc Testing?

As noted above, both ASTM F1959 (fabrics and systems) and ASTM F2178 Arc Test Methods (face protective product s). Figure 2 shows an F2178 arc test using an instrumented head.

- The top graph provides the electrical parameters of the test, the arc current, voltage and duration in milliseconds and cycles. The horizontal axis is in milliseconds, i.e. 1000 millisec onds is equal to 1.0 second. This arc exposure is indicated to be 130.4 cycles which equates for our 60 cycle per second AC electrical system to approximately 2.2 seconds or 2200 milliseconds.

- The bottom graph shows no sensor responses (these were turned off or shielded for this test) but the graph does show the Stoll curve for Mannequin B

- The middle graph shows four sensor responses in addition to the Stoll curve for Mannequin A. The four sensor data plots are the two eye sensors, the mouth sensor and the chin sensor.

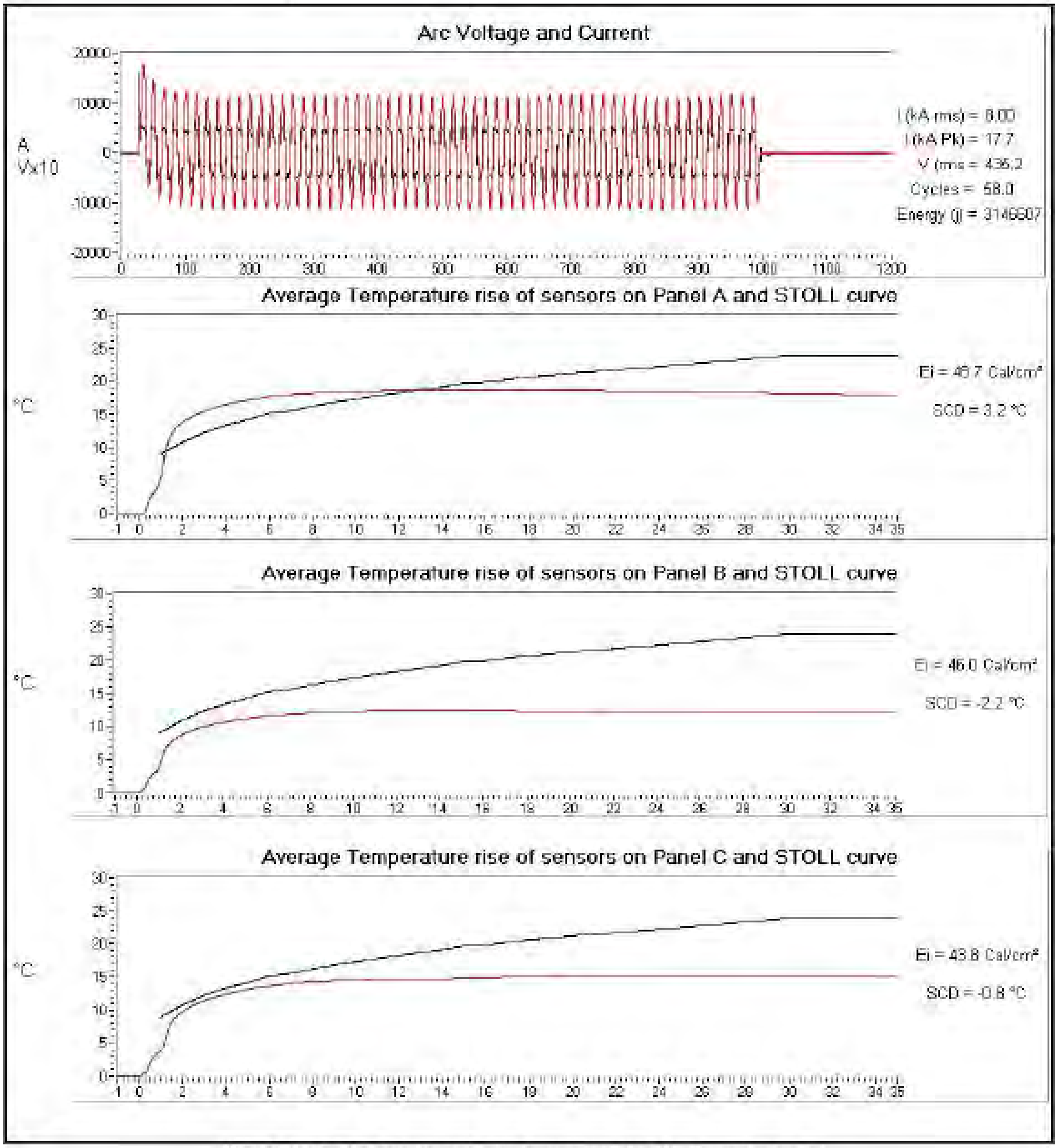
- The exposure on Mannequin Head A is determined by monitor sensors and is noted at the bottom of the chart at 95.6 cal/cm^2. This high level exposure is being used because we are testing an experimental 100 cal hood.

- For Mannequin A, we see only the chin sensor exceeds the Stoll curve. The eye and mouth sensors remain well below the Stoll curve. In this case, we would predict that the chin of Mannequin A would have likely received a second -degree burn, but the face in the areas of th e eyes and mouth would not have received a second-degree burn injury.

In this test, we are using an R&D 100 cal hood and adding prolonged afterflame due to contamination of the sample with mineral oil. The intent is not what occurred in this particular test, but rather to understand how the Stoll curve is used in the F2178 Arc Test Method.

Thu, Jul 11, 2002	High Current Test Laboratory Kinectrics Inc. Test Sheet	KINECTRICS
Test # 02-1905		
WO#: 9504-011		

Client:	Description:
Oberon Company	Power Arc Tests with flat panels at 12 inches, 0.75" s.s electrodes in accordance with ASTM F1959-99 A: sample 701, 2x 716, 704 B: 702, 2X 716, 704, C: 701, 2x 716, 704



PRIVATE INFORMATION. This test data shall not be disclosed or distributed without permission of the client.

Figure 2 Applying the Stoll Curve to an ASTM F2178 Arc Test

Exhibit 9

CALIFORNIA PUBLIC UTILITIES COMMISSION

CPSD

Consumer Protection and Safety Division

An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach

Prepared By

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September 14, 2005

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EXECUTIVE SUMMARY

This report was prepared at the request of the Consumer Protection and Safety Division of the CPUC for an assessment of public safety issues that should be considered regarding the proposed siting of an LNG import terminal in the Port of Long Beach.

The history of LNG importation in the United States is reviewed, describing the siting and continuing operation of the present six LNG import terminals, and the proposal for a very large expansion in the country's LNG infrastructure - more than fifty proposals for LNG import terminals to be located in the continental United States, Southern Canada, Mexico, and the Caribbean Islands – is described. As there appear to be many more proposals than for which there is a demonstrated need, it is all the more important to ensure that the siting process involves, to the maximum extent possible, careful consideration of potential hazards to the public and adjacent infrastructure so as to give full consideration to the best alternatives available.

The potential hazards to the public of the proposed POLB terminal are defined as fire and explosion hazards, and an assessment is provided of the adequacy of the present regulation, 49 CFR 193, to protect the public.

Since the regulations were promulgated in the early Eighties, after the terminals now operating had been built and commenced operation, and since there was no rush to build additional LNG import terminals until about the year 2000, the regulations were largely unused for import terminal siting. As a result, the regulations did not, and still do not, give serious consideration to the terrorist threat that began in this country September 11, 2001. The current regulations do not effectively address the many serious questions posed by the present requirement to consider events that could be caused by malicious intent, nor is sufficient attention being paid to the reality that malicious intent changes the whole safety picture – hence the process has outrun the development of the regulations to deal with it, and the present regulations fail to address this most important new paradigm.

Most importantly in consideration of the post 9/11 threat, there is presently no requirement, much less enforcement, of exclusion zones to protect the public from LNG spills which could occur from the ships that serve the import terminal. The failure to provide for the protection of the public and surrounding infrastructure from major releases of LNG that could occur from the ships serving the facility must be considered all the more important now as a result of recent government sponsored reports, for which there is now scientific consensus, that indicate that the danger zones extending from large, but credible, spills on water are likely to pose greater threats than would either accidental or terrorist caused releases from the land part of the terminal.

The regulation does not provide for consideration of boiling liquid expanding vapor explosions (BLEVEs) or unconfined vapor cloud explosion (UVCE) hazards, although the proposed terminal is designed to import LNG containing natural gas liquids (NGL) in amounts sufficient to raise serious questions about the potential for UVCEs following large LNG spills. The possibility of BLEVEs of LNG ship tanks, particularly the ship tanks which rely on non-fire-resistive insulation to keep the LNG from vaporizing, is not considered, although it is clear that there is a significant potential for occurrence of cascading failures that could jeopardize the ship and all of its content of LNG.

The report then presents an assessment of the consequences to the public that could result from credible accidental or terrorist caused releases of flammable liquefied fuels, either from the land part of the facility or the ships that would serve it.

Accidents and Terrorist Actions

The current regulations, particularly regarding provisions for public safety, focus on the land based part of the terminal. There are specific requirements for liquid containment and impoundment systems that are designed to limit the spreading of LNG that might be released either from the LNG tanks themselves or from transfer lines in the facility. But such control and mitigation measures could not be effectively applied to releases that could occur from an LNG ship, either at the jetty or in transit thereto, because spills onto water could not be effectively contained.

For spills on water, there have been government sponsored studies that provide information sufficient to define the (credible) spills that could occur as well as the consequences that could result.

The ABS Group and Sandia reports agree that the release of LNG in the amount of approximately 3,000,000 gallons (half of one typical LNG ship tank) is credible,

- in that such a release could result from accidental collisions between ships with sufficient momentum (mass and speed) to cause such a breach of containment, or

- that such a release could be caused by terrorists with means that are readily available to them.

Furthermore, the ABS Group and Sandia reports agree that a release of 3,000,000 gallons of LNG onto water could result in:

- Pool fires which would expose persons with unprotected skin to thermal fluxes (5 KW/m^2) that could cause second degree burn injury in approximately 30 seconds at a distance of approximately 1 mile, and

- Flammable vapor clouds, if the spilled material were not ignited upon release, that could extend downwind to distances between 2 and 3 miles. It is reasonable to assume that persons caught in the fire if the cloud were ignited would be killed or seriously injured.

The author is in essential agreement with these consequence estimates but believes the following modifications are required if they are to be used to ensure public safety:

- Since the thermal radiation flux criterion (5 KW/m^2) used by Sandia and the ABS Group could cause second degree burns in thirty seconds, it is not sufficiently protective of public safety; a lower value, approximately 1.5 KW/m^2, is recommended here. This value is already being used by other segments of the regulatory system, both nationally and internationally, based on its definition as the highest thermal flux to which an unprotected person can be continuously exposed without injury. If the 1.5 KW/m^2 criterion is used, it is anticipated that the distance of 1 mile (associated with the higher flux level) would be increased to between 1 ½ and 2 miles.

- As the Sandia Report states unequivocably that cascading failures of ship tanks cannot be ruled out and further states that in their opinion failures of as many as 3 tanks could occur, this scenario must be considered credible. As Sandia estimates that the hazard distance from this scenario could be extended by approximately one-third, the distance to the 1.5 KW/m^2 flux level would then be increased to approximately 2 ½ to 3 miles.

- The ABS Group's high-end estimates for the vapor cloud distance to the 2.5 % gas concentration level (based on releases from a 5 meter diameter hole in the containment) are approximately 3 miles. The Sandia estimates for the credible scenario analyzed are closer to 2 miles, but their calculations reflect the distance to the 5% gas concentration level rather than the 2.5% level which is accepted to represent the better criterion for vapor cloud travel distance that could pose a hazard to the public. Use of the lower flammable gas concentration criteria would be expected to extend the hazard distance to about 3 miles.

Based on this information, which the author believes to be the best available, and which is in general agreement with widely held views in the scientific community, a minimum distance is specified here for the extent to which the public could be put in harm's way from the initial release of approximately 3,000,000 gallons of LNG onto water at the POLB. It is approximately 3 miles.

Consideration of Worst Possible Cases

A minimum 3 mile radius circle around the proposed terminal is proposed to demarcate the area in which events deemed credible could cause serious injury to the public. The minimum distance to demarcate expected damage to infrastructure would be of lesser extent, depending on the criterion selected for damage. Any consideration of the consequences to POLB infrastructure must consider the wide variety of flammable and other hazardous materials routinely handled, as the area in which significant damage to infrastructure could occur (beyond the terminal and the ship) encompasses sections of one of the largest and busiest ports in the country. The POLB receives very large crude oil carriers (VLCC) at a jetty located within several hundred feet of the eastern boundary of the proposed LNG facility, and a major container terminal which almost certainly receives hazardous cargo lies adjacent to the western side of the proposed site, along which the LNG ship will be berthed.

It must be emphasized that the 3 mile distance recommended here is based primarily on the assumption that approximately 3,000,000 gallons of LNG is spilled onto water, as it appears there is little doubt that either pool fire radiation thermal fluxes or flammable vapor clouds from such a spill could put the public in harm's way out to that distance. However, it is a minimum specification, because it does not address the possibility of more serious events which could occur.

There is very real concern that such events as provide the basis for the 3 mile consequence distance would be of such severity as to make it highly likely, if not almost certain, that further failures of containments would occur. In particular, there is serious concern that the exposure to the ship from such a pool fire would have the potential to cause cascading failures of the remaining tanks on the vessel, resulting in total loss of the vessel and burning of its contents. There can be no doubt that the consequences of such a worst-possible-case event could be more severe.

Finally, the report states that the vulnerability of the land based part of the facility needs to be considered more carefully, as the author believes that insufficient attention has been given to the vulnerability of the land based facility to such natural phenomena as earthquakes and tsunamis, as well as to the facility's vulnerability to terrorist attack.

CHAPTER 1

INTRODUCTION

This report was prepared for the Consumer Protection and Safety Division (CPSD) of the California Public Utilities Commission. The CPSD requested that I prepare a science-based assessment of public safety issues that should be considered regarding the proposed siting of an LNG import terminal in the Port of Long Beach, California.

My resume is attached as Exhibit A. I have been researching methods for assessing the potential consequences of major spills of liquefied natural gas (LNG) and natural gas liquids (NGL) for more than thirty years. As the history of LNG import terminal siting in the United States, indeed the world, is largely confined to a similar period, I believe that I have a unique perspective on the issue of the hazards which LNG terminal activities can pose to public safety. I also believe that it is important to consider LNG safety issues in the broader context of increasing usage by society of other liquefied fuel and chemical gases that pose similar hazards. I particularly appreciate this opportunity to put the issues of public safety surrounding the proposed siting of an LNG import terminal in the Port of Long Beach into a scientifically reasoned context - based on my observation and study during the last three decades to understand the consequences that could occur to the public as a result of major spills of liquefied gaseous fuels onto land or water.

In my view, the importance of careful and sober consideration of the potential threat to public safety and to critical infrastructure of the decision to site a large LNG import terminal in the Port of Long Beach cannot be overstated. No liquefied fuel import terminals have been sited in urban areas of the United States since the Distrigas plant began operation in Everett, MA, in Boston Harbor, in 1971. In the interim three decades the world has experienced several catastrophic industrial accidents which were so severe as to importantly influence worldwide regulatory controls intended to lessen the likelihood as well as the potential consequences of accidental releases. Most importantly, no LNG facilities at all have been sited in this country since 9/11, and I believe that 9/11 completely changed, or should and will change, our methods as well as our thinking about the new paradigm in which major hazards complexes must be considered.

It is important for the reader to understand that this assessment is intentionally and solely directed to the realistic definition of the consequences to the public and surrounding infrastructure that could occur from a major release of flammable liquids at the proposed terminal or from the ships that will serve it, with no consideration given to the likelihood of occurrence of the events which are considered I believe that the first step in determining a rationale for a decision whether or not to site the proposed LNG terminal in the Port of Long Beach is to define the possible (credible) consequences of major releases of hazardous materials, and I believe that such determination should be made independently of any arguments advanced regarding the probability (likelihood) of such events' occurrence.

This approach is all the more appropriate since the tragic events of 9/11, as historical experience regarding LNG accidents (or accidental occurrences of any kind) cannot be used to quantify the probability of a terrorist attack.

1.1 LNG Importation in the United States

Proposals for large scale importation into the United States are not new, importation of LNG into the States having begun in the early Seventies. Although the technology of LNG storage and shipping has advanced in several areas, there are many similarities between the storage and shipping methods utilized in the Seventies and those proposed today. Indeed, all of the import terminals built in the Seventies are still in operation, and are proposed for operation for at least two decades into the future.

By the early Seventies the marine carriage of LNG had been proven technologically, and several ventures were proposed to import LNG into the United States, at the time principally from Algeria to the east and gulf coasts and from far-east gas sources such as Indonesia to the west coast. By the end of the Seventies, four import terminals were operating on the east and gulf coasts of the United States – at Everett, Massachusetts, beginning in 1971; near Savanna (Elba Island), Georgia, beginning in 1978; at Cove Point, Maryland, beginning in 1978; and at Lake Charles, Louisiana, beginning in 1982. A fifth terminal, at Kenai, Alaska, intended for export, principally to Japan, began operation in 1969. The terminal in Everett has been in operation continuously; the terminals at Elba Island, Cove Point, and Lake Charles are currently operating after a period in mothballs (different for each) which resulted from decreased need for LNG importation. The fifth import terminal was constructed and began operating in Penuelas, Puerto Rico, in 2000, and the Gulf Gateway Energy Bridge deepwater port commenced operation this year in the Gulf of Mexico.

To serve the needs of these United States import terminals as well as the needs of even faster growing LNG importation by Japan and Europe, a fleet of LNG carriers was constructed. Currently, there are approximately 165 LNG carriers in service worldwide, several of which were built for the trade that began in the Seventies. Eighteen carriers have been retired from service, and approximately 85 new ones are on order. Typical LNG carriers built in the Seventies, some of which are in use today, carry approximately 125,000 cubic meters of LNG, but the proposed terminals today are planned to receive carriers with capacity up to 250,000 cubic meters (approximately 66 million gallons).

During the period in which the first four terminals (described above) were constructed, there were additional proposals to build and operate LNG import terminals in California, with three specific sites receiving principal consideration – Los Angeles Harbor (Terminal Island), Point Conception, and Oxnard. For all three of these proposed locations, detailed risk assessment studies were prepared to define the hazards to the public that might occur as a result of accidental spills of LNG. None of the proposed California terminals were built, presumably as a result of indications that they would not be profitable in view of a reassessment of the demand for natural gas. It is important to note that because the terminal project applications were withdrawn for reasons other than consideration of their safety hazards, it is fair to say that the issues of public safety were never effectively resolved, and consideration of the risks to the public of such ventures languished - until about the year 2000.

1.2 Proposed Expansion in LNG Importation

The United States is presently considering a very large expansion of its LNG import infrastructure. As addition to the five land and one offshore import terminals currently operating in this country, as many as fifty new LNG import terminals to be sited in the continental United States, Southern Canada, Mexico, and the Caribbean Islands have been proposed. Additional proposals have been announced during the preparation of this report. All of these plans are said to be based on projections for greatly increased LNG use, both in quantity and as a percentage of total energy use.

Although this report is not intended to address the need for new LNG import terminals, I think that it should be noted that there have been no projections of demand for LNG that suggest our need (before 2025) for more than perhaps as many as a third of this number, and quite likely fewer. Viewed thus, the large number of proposals appears to be in some important part the result of significant competition to “win” in the selection process.

Although the majority of these terminals have been proposed at onshore locations, including some proposed for urban areas, as in Long Beach, a significant number are now planned for installation offshore.

With more proposed terminals than for which there is a justified need, I believe it all the more important to ensure that the siting process involves, to the maximum extent possible, careful consideration of potential hazards to the public and adjacent infrastructure.

1.3 Public Safety Concerns about LNG Terminal Siting

To begin, let me define the terms liquefied natural gas (LNG) and natural gas liquids (NGL).

LNG is natural gas that has been cooled, at normal atmospheric pressure, to approximately -260 ^{o}F, its liquefaction temperature varying depending on the composition of the gas. Methane, the principal component of LNG, cannot be liquefied by pressure alone. Although liquefaction by cooling to higher temperatures (> -260 ^{o}F) at elevated pressure is possible (combinations of cooling and pressurization are utilized in some LNG applications, such as vehicle fuels), the LNG that would be received at the Long Beach Terminal would be contained in ship tanks designed for nominal atmospheric pressure operation, i.e., with design pressures not exceeding approximately one atmosphere, and stored in land tanks under similar, nominally atmospheric pressure, conditions. Based largely on historical precedent, most LNG safety and risk assessments have assumed LNG to be principally methane, and present regulatory requirements for determining danger zones around LNG spills allow, at least implicitly, description of its composition as pure methane.

However, the composition of the LNG that would arrive at the proposed Long Beach terminal will depend upon several variable factors, including the location of gas production (the composition of natural gas from different producing fields can vary significantly) and the degree of processing of the natural gas, either during liquefaction at the export terminal or following the receipt of the LNG at the import terminal, to remove heavier molecular weight hydrocarbons such as ethane, propane, and butane. Such heavier molecular weight compounds, mixed in varying concentrations, are commonly referred to as natural gas liquids (NGL). Since the proposed terminal in Long Beach could import LNG containing substantial amounts of natural gas liquids, and since the terminal is designed to process the LNG after receipt to separate the NGL for (separate) distribution, a thorough assessment of the hazards which could be posed to the public should consider both the LNG and NGL components of the facility. Furthermore, since the degrees of hazard to the public depend, beyond the most immediate and compelling factor of the very large quantities of LNG, on important differences that are known to exist in the fire and explosion hazard potentials of LNG and NGL, any assessment of the potential hazards to the public from the proposed terminal should consider the hazards specific to LNG and NGL, as well as any potential for more serious events which could result from the storage and handling of the materials in combination.

The concerns for public safety associated with the current proposals to site new LNG terminals are essentially the same as those identified in the Seventies when LNG terminals were introduced to the United States. I have observed that the degree to which the public raised concerns about public safety varied considerably in the gulf, east, and west coast regions. There appeared to be the least opposition in the gulf coast region, with somewhat greater resistance on the east coast, particularly in New York and New England, and perhaps greatest regarding the siting of the three terminals proposed in California. It is significant, I believe, to the present discussion to note (again) that the Distrigas terminal in Everett, Massachusetts, is the only terminal constructed to date in a major urban area in the United States. There have been voiced far more concerns about the Everett facility than for the other terminals, which by comparison are located more remotely (from the public).

It is also my observation that similar variations exist in these same regions today in their response to LNG terminal siting proposals – least in the gulf region (with the notable exception of Mobile, Alabama, where Exxon Mobil has withdrawn its proposal for a terminal in Mobile Bay), followed by similar responses (both for and against the projects) from the public to proposals on the east and west coasts. So far, the proposals for terminals to be sited in unarguably urban areas, notably Fall River, Massachusetts, on the east coast, and Long Beach on the west coast, appear to be among the most contentious (regarding the public safety issue) of the proposals under active evaluation.

But there are present today (at least) three new and significant factors that require careful consideration before reaching a decision to site a liquefied gas import terminal, particularly if the site is in an urban area.

The first is the aforementioned offshore placement of LNG import terminals. Although at the beginning of the current expansion phase, there were many objections advanced to the offshore alternative, including most prominently issues of economy (it was suggested that offshore installations would be too expensive) and increased vulnerability to scheduling interruptions caused by weather, the offshore option appears to be gaining acceptance, with several terminals proposed for offshore locations off of the west, gulf, and east coasts. At least one offshore LNG facility (The Gulf Gateway Energy Bridge deepwater port, owned by Excelerate Energy Limited Partnership) has commenced operation this year in the Gulf of Mexico. It appears that the viability, of at least this type of offshore importation project (Energy Bridge), is no longer in question.

Second, during the ensuing three decades since the LNG terminals on the east and west coasts commenced operation, the world has experienced several catastrophic industrial accidents, the major consequences of which should be seriously considered before reaching a decision to site a potential major hazard industrial facility, such as the proposed LNG terminal, in a congested area such as the Port of Long Beach. Most importantly to the present in that regard, there have been a substantial number of liquefied gaseous fuel accidents involving containment failures due to boiling liquid expanding vapor explosions (BLEVEs) as well as unconfined vapor cloud explosions (UCVEs), the most severe in this hemisphere (in terms of human casualties) having occurred in an outlying area of Mexico City in 1984. That event resulted in more than 600 deaths, thousands of serious injuries, and the complete devastation of an entire NGL storage and distribution facility.

Third, and perhaps of greatest importance to the present consideration of siting an LNG terminal in the Port of Long Beach, is the terrorist threat, which the public perceives with growing concern. Although sabotage appears to have been given some consideration in the siting of terminals in the Seventies, to my knowledge no organized efforts were undertaken at that time to quantify the consequences that might result from sabotage or to attempt to quantify the likelihood of such occurrences. But, since 9/11, concerns about terrorist attacks that could pose significant threats to public safety are very real, and they are fast growing. The energy infrastructure of our country is of particular concern, because of the potential for terrorist attacks to cause events that could directly endanger the public as well as deprive us of energy that we require.

The Department of Homeland Security has identified LNG infrastructure, one component of the much larger chemical/energy infrastructure, as a potential terrorist target of concern. The Department's concern results, primarily I believe, from the recognition that liquefied gas fuel storage tanks, either on land or on ships, must necessarily concentrate very large amounts of energy (as LNG and NGL) in individual containment systems in order to be economical. The terminal proposed for the POLB will have storage capacity for approximately 86,000,000 gallons of LNG, and the ships that are initially planned to serve the terminal will carry approximately 38,500,000 gallons of LNG. However, the facility is being constructed so as to enable it to receive ships carrying up to about 53,000,000 gallons of LNG, and possibly more. The potential for terrorist attack to release large quantities of highly flammable fuels from such large storage vessels thus is seen to carry with it the potential for such attacks to endanger the public offsite as well as to effect horrendous damage to infrastructure. In my opinion, these factors demand that LNG infrastructure such as the proposed Long Beach terminal be identified as potential terrorist targets of opportunity.

I believe, and have so testified before Congress, that since 9/11 we no longer have the luxury of considering only means for reducing the probability of accidents (through more effective management strategies) to a level that is considered to justify the attendant risk – we now are forced to consider malicious acts as well. And, I believe that it is imperative that the dangers to the public from possible spills that could occur as a result of terrorist attack, particularly those spills which might occur from a tankship and thus onto water (for which there are few if any control measures), be most carefully considered in the current rush to site additional LNG import terminals in our country. Finally, in this regard, I have notified the Secretary of Homeland Security (Exhibit B) of my concerns about specific features of LNG carriers which I believe may make those ships vulnerable to terrorist attack. The specific issues, which I will address later in order to put them into a proper context, are the use of non-fire-resistive insulation on the containment vessels (LNG tanks) and the potential for major failures of the ship's structure due to direct contact with spilled LNG, which, having temperatures as low as (minus) 260 ^{o}F, has been demonstrated repeatedly to cause brittle fracture of carbon steels. Since my appeal to the Department of Homeland Security, there have appeared important reports of studies designed to clarify several outstanding issues, particularly those issues regarding the consequences that can be anticipated from large releases of LNG onto water; I will attempt to summarize the current state of our knowledge regarding these critically important matters in this report.

Finally, I have tried to prepare this report in a form which will be useful to policy makers, whom I believe are not always sufficiently informed on such matters, and to the public, whom I believe are becoming increasingly concerned, as I am, that issues of public safety surrounding the nation's chemical/energy infrastructure are not receiving the attention that is demanded, particularly post 9/11. Quoting from the foreword which I wrote for the chapter on Major Hazard Control, in <u>Lee's Loss Prevention in the Process Industries</u>, "It is my belief that the major hazards problems society faces are less a problem of insufficient information about those hazards and more a problem of insufficient application of the tools that we have in hand." In this regard, I believe it is important to note that the reports on LNG hazards which have been recently prepared and mentioned above, especially the reports by the ABS Group and the Sandia Group, do provide information which provides effective answers to several technical questions concerning large spills of LNG onto water which have been particularly contentious. It is in that vein that I have prepared this report with a view to cutting through the technical details to provide the public with my summary of the information which is now available, along with my candid view of what that information should mean to the public and its policy makers whom are considering the siting of an LNG import terminal in the POLB. I believe it is absolutely imperative that we get this one right, as it will have the potential for setting extremely important precedents in our attempts to balance the risks and benefits of increased LNG importation, that task having been made immensely more difficult by the threat of terrorist attack.

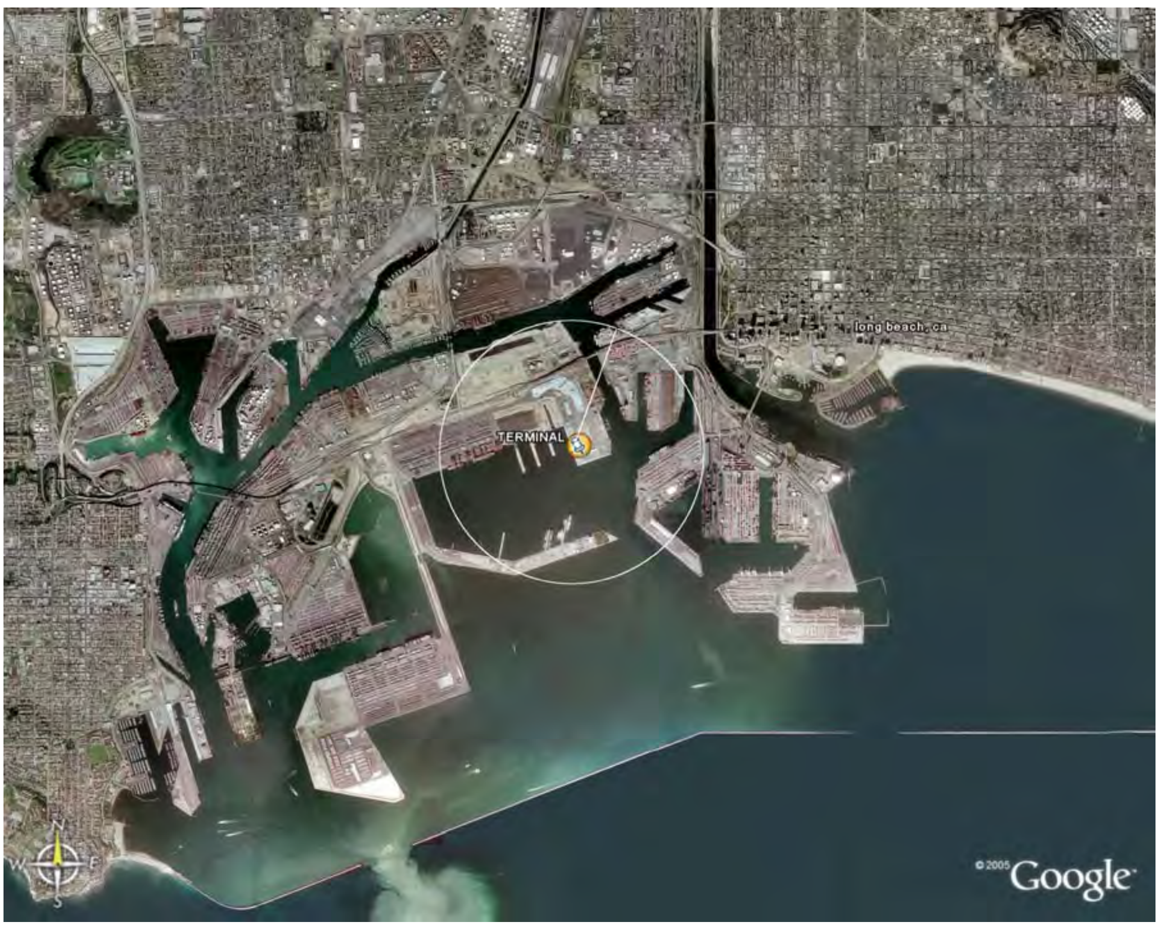
CHAPTER 2

POTENTIAL HAZARDS TO THE PUBLIC OF THE PROPOSED LNG TERMINAL IN THE PORT OF LONG BEACH

2.1 Location and Description of the Proposed Terminal

Location

The satellite photo below shows the harbors of Los Angeles and Long Beach, with adjacent cities of Los Angeles to the west and north and Long Beach to the north and east. The proposed location of the LNG terminal in the Port of Long Beach is on an approximately twenty-five acre site on the east side of Pier T. For purposes of scaling, a circle with one mile radius is centered on the location of the tanker offloading site, which will be on the west side of the land parcel designated "TERMINAL".[1]



[1] This satellite view, which extends to distances of three to four miles from the proposed terminal, will be used later in this report to delineate the minimum extent of zones in which the public and infrastructure could be endangered by major releases from containment of flammable liquefied gases - for which there is now good scientific agreement that are deemed to be credible.

Descripton

For purposes of this report, which is primarily directed to consideration of public safety issues, the principal components of the LNG terminal are summarized below.

- An LNG ship berth with 4 LNG unloading arms;
  - 2 liquid arms designed for a capacity of 24,150 gallons per minute (gpm) each, allowing ship offloading at 48,300 gpm,
  - 1 liquid/vapor hybrid arm, and
  - 1 vapor arm.

- 2 LNG receiving tanks, each with a gross volume of 42.3 million gallons of LNG at a temperature of -260 F and a normal pressure of 1 to 3 psig. (LNG-1, LNG-2 on plot plan);

- 6 in-tank LNG pumps, each sized for 2,500 gpm;

- Seven LNG primary booster pumps, each sized for 1,830 gpm;

- Seven LNG secondary booster pumps; each sized for 1980 gpm;

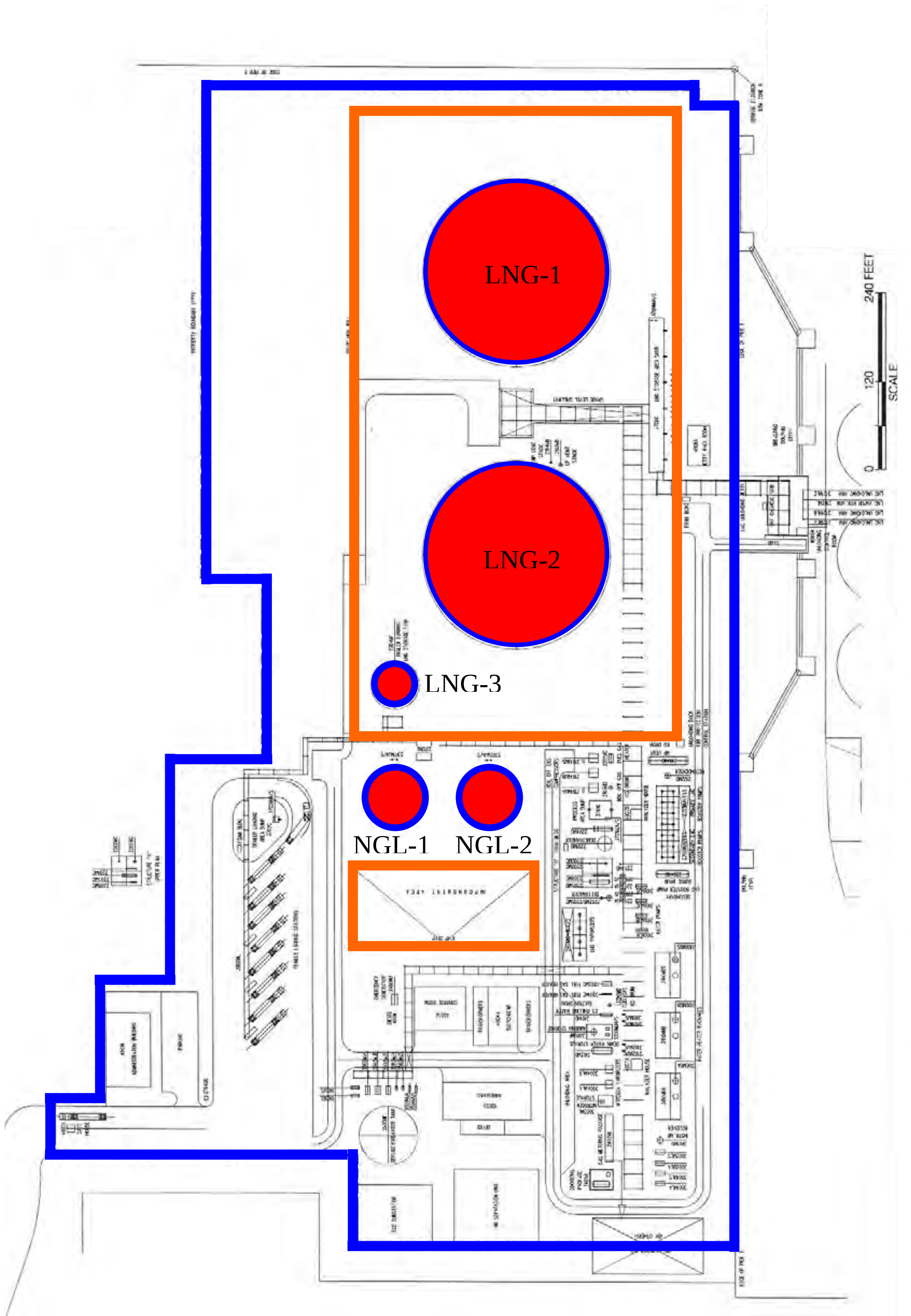
- Four shell and tube vaporizers, each sized for 350 million standard cubic feet of gas per day using a primary closed loop water system heated with three direct-fired heaters and circulation pumps;

- Three boiloff gas compressors and associated condensing systems;

- An LNG trailer truck loading facility, including an LNG receiving/storage tank with a capacity of 1,000,000 gallons of vehicle quality LNG for distribution via eight trailer loading bays (LNG-3 on plot plan). An average of 45 trucks will be loaded per day.

- An NGL recovery system, for which the final design appears to remain under consideration, will provide for the recovery and distribution off site of natural gas liquids, principally ethane and propane, via pipeline and/or trailer truck loading;

The terminal plot plan follows, with designation of the location of the primary storage tanks (in red), spill impoundments (in orange), and site boundary in blue. The total area of the site is approximately 25 acres. (Information from Sound Energy Solutions Long Beach LNG Import Project Resource Report 1, General Project Description, Jan. 2004)



***The author is aware that consideration is being given to altering the requirements for NGL storage, perhaps even eliminating it. As the author is not privy to any final decision in this regard, this description is based on the site description from SES' January 2004 report.

2.2 LNG (Liquefied Natural Gas) and NGL (Natural Gas Liquids) Hazards

The primary hazards (to the public) that can result from the errant release of liquefied gas fuels such as LNG and NGL from the proposed terminal activities in the POLB are:

- Fire hazard
  - Liquid pool fires
  - Vapor cloud fires
- Explosion hazards
  - Confined vapor cloud explosions
  - Unconfined vapor cloud explosions (UVCE)
  - Boiling liquid expanding vapor explosions (BLEVE)

There are other hazards that require identification and consideration. However it is noted here that they can be of different degrees of concern for LNG and NGL and, in any case, are of less concern than the fire and explosion hazards because, with caveats noted in the specific descriptions that follow, these hazards would not be expected to extend offsite and therefore would not directly affect the public:

- Toxicity hazard
- Cryogenic (“cold” burn) hazard
- Rapid phase transition (flameless explosion) hazard

These last three hazards will be described briefly, for completeness, and then relegated to secondary importance in order to prioritize the main concerns for public safety.

2.2.1 Toxicity Hazards

LNG is natural gas that has been cooled to its condensation temperature; its composition can vary significantly depending upon the source of the gas. However, LNG normally contains as its principal component methane, with heavier hydrocarbons such as ethane, propane, butane, etc., comprising the much smaller remainder.

For purposes of assessing the hazards of LNG, it is appropriate to consider the toxicity of LNG vapor to be that of methane, the principal component, with modification as deemed necessary to allow for consideration of the toxicity of the heavier components which may be present.

Since methane is not a toxic material, it normally poses a hazard only if breathed in sufficient quantity to displace necessary quantities of oxygen (asphyxiation). Consequently methane is not expected to pose a toxicity hazard to the public at the proposed terminal since the public would not be expected to be exposed to high enough concentrations to result in severe displacement of oxygen. Furthermore, the toxicity of the heavier components contained in the LNG, which for our purposes here also can be considered to be simple asphyxiants, is not expected to pose a hazard to the public because of the low concentrations to which the public would be exposed.

Similarly to LNG, which usually contains small amounts of NGL, the components of NGL (ethane and propane are suggested to be the primary natural gas liquids to be stored at the Long Beach Terminal) are not expected to pose a primary hazard to the public, since concentrations of these gases sufficient to asphyxiate people would not be expected to extend off site except in the most extreme conditions, and in such cases the fire and explosion hazards pose much greater hazards.

2.2.2 Cryogenic ("Cold Burn") Hazards

LNG, as pure methane, has a temperature of approximately -260 F. It is a cryogenic liquid, and exposure of human tissue to such temperatures can cause immediate severe injury. The author investigated an accidental release of LNG that occurred in 1977 in Arzew, Algeria, where a man was killed as a result of being deluged with LNG from a ruptured cryogenic valve. However, injury to the public is not expected to occur by exposure to such extreme temperatures because the region near a release of LNG where contact with either the liquid or cold vapor could cause such "cold" burns would not be expected to extend to distances where the public could be exposed.

Natural gas liquids such as ethane and propane, unlike methane, can be liquefied by pressure alone. Consequently, NGL can be stored either under pressure, refrigerated, or in combination. However, since refrigerated NGL is at a much higher temperature than LNG, and since low gas temperatures that could result due to depressurization of (pressurized) NGL would not be expected to extend to distances where the public could be exposed, NGL is not expected to pose "cold burn" hazards to the public at the POLB.

2.2.3 Rapid Phase Transition (Flameless Explosion) Hazards

If a small volume of LNG is rapidly poured into water, the LNG can be heated by the water to temperatures greater than its normal boiling point while remaining in the liquid state. The (liquid) LNG is then said to be *superheated*. If several degrees of superheat are achieved, the evaporation (boiling) process which follows can be essentially instantaneous, with the result that significant pressure increases (overpressures) can result. Such overpressures can cause damage similar to the overpressures caused by more *conventional explosions* which are normally associated with rapid combustion of a chemical or fuel.

The rapid phase transition (RPT) of LNG added to water was first observed, unexpectedly, in a laboratory experiment performed in the Sixties at the U. S. Bureau of Mines. Subsequent research into the phenomenon has been performed by several organizations, most prominently by inhouse industry research programs. All of the work of which I am aware is relatively small scale, but there have been calls for additional research to better determine the scaling characteristics of rapid phase transitions.

As in the case of cryogenic (cold burn) hazards, the damaging overpressures that could occur from rapid phase transitions would be local, and the resulting overpressures are not expected to extend to distances which could endanger the public.

However, there is continuing interest in, and a need for, further research to study the scaling characteristics of RPT's. Although dangers to the public are not expected to result directly from RPT overpressures, their importance in the public safety context lies in the potential for RPT's to cause secondary damage which could lead to cascading failures and further releases of LNG.

The author is not aware of damaging rapid phase transitions having occurred for spills of NGL onto water, although the NGL content of LNG, which is much colder, appears to have some relation to RPT occurrence (as it does as well to UVCE occurrence, as we will see). In any case, as large spills onto water at the POLB terminal are expected primarily from the LNG carrier, and since impoundment areas are expected to be provided for any NGL storage tanks, large spills onto water of NGL at the terminal are not expected.

2.2.4 Fire Hazards

There are two ways that very large fires (that could endanger the public) can result from a major LNG spill – pool fires and vapor cloud fires.

Pool Fires on Land

Spilled LNG will evaporate rapidly due to high rates of heat transfer from the warm surroundings (primarily the earth's surface) to the cold liquid. The vapor evolving from the liquid pool will mix with air to form a gas-air mixture which will burn in the concentration range of approximately 5% to 15% LNG vapor (the concentration range that is flammable for methane-air mixtures). Such mixtures of LNG vapor and air will inevitably form when LNG is spilled, and if an ignition source such as an open flame or spark is present at a location where the gas mixture is within the flammable range a large pool fire will result. In this instance the fire will immediately burn through the gas mixture from the point of ignition to the liquid pool. The resulting "pool fire" is similar in many ways to any other pool fire where liquid hydrocarbons, such as gasoline, are burning – but it should be noted that because the LNG is so cold, heat transferred from the surroundings will cause the LNG to evaporate much faster, thus effectively "feeding" the fire at much higher rates than would occur from a gasoline spill, and even faster than would occur for a refrigerated NGL spill (because the NGL is not nearly as cold). In any case, the fire results from the combustion of the fuel vapors which have evaporated from the liquid pool and have been mixed with air to result in flammable concentrations. An LNG pool fire, which has the potential to burn significantly "faster" than higher boiling point hydrocarbons, can seriously endanger the public, either through direct contact with the fire, or through heat radiated by the fire.

It should be noted here that it is in this context that the statement that "LNG does not burn", or variations thereon, is frequently found in the literature purporting to educate the public regarding LNG safety. While the statement is literally true, it is not helpful, and it can be seriously misleading, as the statement is also (literally) true if applied to any other liquid hydrocarbon fuel such as gasoline or NGL. It can be misleading because the statement that LNG does not burn could imply that there is something different in the combustion mechanism of LNG from other hydrocarbon fuels – in this sense, there is not.

Because very large releases of LNG, attended as they would likely be by violent circumstances which could result in ignition (thus preventing the formation of a flammable vapor cloud that could leave the site), I believe that the potential danger to the public from LNG spills is probably greatest from the very large pool fires that would more likely occur. I emphasize that I am talking about fires resulting from the spillage of several millions of gallons of LNG (each of the two primary storage tanks at the POLB terminal will contain more than 40,000,000 gallons of LNG). We have no experience with such fires, but we do know that they could not be extinguished and would just have to burn themselves out, and the radiant heat extending outward from the fires edge could ignite combustible materials as well as cause serious burns to people at considerable distances from the fire's edge. The distances from such fires to which harm to the public could extend will be a primary focus of this report.

NGL pool fires on land may be considered similarly with LNG pool fires, with at least two potentially important differences, the implications of which are not completely understood, especially for very large fires:

- NGL, whether it be pressurized or refrigerated, will not evaporate as fast as LNG will due to heat transfer from the ground surface, hence the burning rate (and associated heat flux from the fire) may be somewhat smaller.

- NGL fires have been observed to produce more smoke than LNG fires, with the result that the heat flux radiated out from the fires edge can be significantly changed.

Vapor Cloud Fires

If LNG is spilled and evaporates to form a gas/air mixture in which there are located no sources of ignition (an ignition source is a high temperature "point" source of energy such as a spark or flame), the gas-air mixture ("gas cloud") which forms, although possibly containing a large amount of gas that is in the flammable concentration range, will not ignite, and the cloud will drift until it either contacts an ignition source or all of the cloud becomes diluted below its *lower flammable limit* (approximately 5% methane in air) - it will then disperse harmlessly. If ignition occurs during the drifting of the cloud the result is a vapor cloud fire.

If the gas cloud formed is not ignited immediately it will be carried downwind, or will spread more or less radially (due to gravity forces on the heavier-than-air gas mixture) in the absence of wind. Both spreading by the wind and gravity spreading are accompanied by gas-air mixing and thus dilution of the cloud.[2]

If, however, an ignition source is encountered at a location where the gas concentration is within the flammable concentration range, ignition will occur (at that location) and the fire will spread throughout the part of the cloud which is in the flammable concentration range. This is the so-called "flash fire" or vapor cloud fire. An LNG vapor cloud fire can endanger the public, either through direct contact with the fire, or through radiated heat from the burning cloud.

I think it important to state here again that my opinion that pool fires pose a greater risk than vapor cloud fires (see above) is based on the potential for high consequences *accompanied by the high probability that ignition will occur* as a result of the violent circumstances that would be expected to effect such a release. However, as I have said above, the consequences of credible events that might occur that could impact public safety require determination *independently* of consideration of the likelihood of the occurrence. Finally, I note here that the current federal regulations for siting LNG facilities require the determination of vapor cloud dispersion exclusion zones to protect the public safety, and no consideration is given to ignition probability in the determination of those exclusion zones. Therefore, it remains critically important to

[2] Photograph of an LNG spill onto water at Maplin Sands, UK, in the Eighties. The LNG spill volume was of order 10,000 gallons, with a moderate wind from top right to bottom left. White objects are floating instrument platforms. For scaling, radius of circle (dike) is approximately 450 feet. This spill volume is representative of the largest LNG spills that have been conducted on water to study vapor dispersion.

determine the potential consequences of delayed ignition of large flammable vapor clouds.[3]

[3] Sequence of photographs (top to bottom) showing an LNG vapor cloud fire over water – tests conducted at Maplin Sands, UK, in the Eighties. Wind is from right to left with maximum visible cloud extent at the left of the top picture. Ignition occurred near the left side of the gap in the cloud in the top photograph, and the cloud has burned nearly back to the liquid pool in the bottom photograph. Spill volumes are similar to the photograph in footnote 1, and the diameter of the circular dike is approximately 900 feet.

Vapor cloud fires that would result if an NGL vapor cloud were ignited may be also considered similarly to LNG fires, with at least three potentially important differences:

- The flammability range for NGL is significantly different than for methane, the principal component of LNG. Most importantly here, the lower flammable limit for NGL is lower than that for LNG; for ethane it is about 3%, and for propane it is just over 2%. This is significant because it means that NGL vapor clouds will remain flammable at lower concentrations, and therefore will have the potential to remain flammable for greater distances (than for an equivalent volume of methane vapor). As a result, the extent of potential danger to the public is increased.

- NGL vapors may be heavier than air because of their higher molecular weights. For example, propane's molecular weight is 44, causing its density to be about 50% greater than air at the same temperature and pressure. This is important because the density stratification in such a vapor cloud decreases the dispersion rate (by decreased mixing with air) and can result in increased downwind travel before the gas cloud concentration falls below the lower flammable limit, thus increasing the extent of potential danger to the public.

- As will be discussed in more detail below, NGL vapor clouds are known to be susceptible to high-order explosion if ignited, even in the absence of confinement. Therefore, the improbability of explosion due to absence of confinement, a factor which is considered highly important in the assessment of LNG safety, does not apply to NGL vapor clouds. As there have been several catastrophic explosions of NGL vapor clouds, this hazard will be considered prominently in this report.

2.2.5 Confined Vapor Cloud Explosion Hazards

There is no need here to further define the potential for explosions of confined LNG or NGL vapor/air mixtures, of which we are all aware. However, the potential for explosions of confined LNG or NGL vapors are important to this hazard assessment because they have the potential for release of energy and ejection of projectiles that could jeopardize other NGL or LNG containments.

2.2.6 Unconfined Vapor Cloud Explosion (UVCE) Hazards

The term explosion is used here to describe combustion reactions (that we normally call "burning", i.e., reaction of the gas in question with the oxygen in the air) which achieve such rapid rates that significant overpressures (local pressures higher than the atmospheric pressure) develop. Such overpressures can cause severe damage – they constitute the "blast" effect in conventional explosions.

The forces released in conventional explosive materials (such as dynamite) typically result from very rapid *reactions of materials that are totally contained in the explosive* *material*. In such materials both the “fuel” and the “oxidizer” are already present. In contrast, explosions of fuel gases such as methane or propane cannot occur unless the gas (fuel) is mixed with air (containing oxygen) such that the mixture has a concentration within the flammable range (for methane this is approximately 5% to 15% in air). Such *physical* processes (as mixing with air), which are necessary for the gas to burn (or explode), place gas/air fires and explosions in a lower hazard class than materials like dynamite, which are “ready to go” if ignited, i.e., without the necessity that the material first be mixed with anything else. Furthermore, if the methane concentration is less than 5% (the *lower flammable limit*) concentration, the mixture will not burn, much less explode – it is said to be too *lean*. Similarly, if the methane concentration is higher than 15% (*the upper flammable limit*) concentration, the mixture will not burn (or explode) – it is said to be too *rich*.

If a methane/air mixture within the flammable concentration range is ignited, the rate of reaction (the burning rate, i.e., how fast the flame moves through the gas mixture) varies depending on a number of factors, one of the most important of which is *confinement.* We all know that natural gas (normally principally composed of methane) explodes all of the time – *when it is confined*. We all have read about, and many have experienced, the blast effect that occurs when leaking (flammable) gas is released into a confined volume (say the kitchen) and its ignition (say by a light switch) blows the building apart.

Conventional wisdom, even scientific opinion, held until fairly recently (the Seventies) that unconfined gas/air clouds such as are formed by gases such as methane, propane, and the higher molecular weight hydrocarbon, will not explode if unconfined. This is important to the present discussion because it goes straight to the question of whether the cloud formed by LNG vapors mixing with air following a major LNG spill could explode (develop damaging overpressures) when the cloud is not confined.

Today, damaging explosions of hydrocarbon gas/air mixtures are of very great concern because of accidents which have demonstrated the propensity of some hydrocarbon gases, when mixed to the correct proportions with air, to explode with devastating damage, *even when unconfined*. There is not time or space here to provide the details, but it can be stated that at least three such unconfined vapor cloud explosions (UVCEs) that occurred at Flixborough, England, in 1974; Mexico City in 1984; and in Pasadena, Texas, in 1989, were so devastating that they resulted in extensive changes in the national and international regulatory requirements for dealing with chemical hazards.

What does this have to do with LNG? There is a scientific consensus (supported by experimental data) that methane/air mixtures which are unconfined are very unlikely to explode. The LNG industry and the Government are sufficiently confident of this fact that the explosion of an unconfined LNG vapor/air cloud is not considered credible. As a result, the most severe hazard is considered to be fire. I have studied this question, and I agree with the contention that unconfined methane/air mixtures are very unlikely (but not impossible) to explode.

But the story doesn't end there. It has already been stated that the composition of LNG imported into the United States varies significantly depending on several factors, most prominently the gas source location. LNG is imported from some locations that provide nearly pure methane. LNG is also imported from some other locations with concentrations of heavier hydrocarbons as high as 15-20%. Such gas is termed "hot gas" in the industry because its calorific value (energy content) is higher than an equivalent volume of methane. Typical heavy hydrocarbon gases present in LNG are ethane and propane, but others are present as well.

We know now that even unconfined vapor cloud explosions (UVCEs) cannot be dismissed for LNG spills if the gas contains significant amounts (say greater than about 12 to 18%, based on Coast Guard sponsored tests at China Lake in the Eighties) of gas components heavier than methane. Furthermore, enrichment in higher boiling point components of the liquid remaining as the LNG vaporizes can lead to vapor cloud concentrations that could pose a UVCE hazard, even if the concentration of the heavies in the liquid initially spilled do not. Since the LNG terminal proposed to be located in the POLB is planned to receive "hot gas"[4], and to engage in the storage and distribution of natural gas liquids (NGL) that are separated from the imported LNG, *questions of whether major releases of LNG at the terminal might pose an unconfined vapor cloud explosion hazard, with the attendant potential to initiate further cascading effects, remain highly relevant*.

There is now no question that GNL vapor clouds can explode with devastating force. Consequently, as the POLB terminal will have some, perhaps yet to be determined, quantities of GNL on the site (primarily ethane and propane), the potential for releases at the terminal to result in high order vapor cloud explosions must be given primary consideration in the assessment of potential hazards to the public and surrounding infrastructure.

Although there are numerous examples of unconfined vapor cloud explosions that have occurred in the chemical manufacturing, storage, and transportation sectors, it is not necessary, nor is there time here, to give a complete list of occurrences. Two events which appear to be highly relevant to this POLB hazard assessment will be highlighted here:

- A fire and explosion occurred in 2004 at the LNG export terminal in Skikda, Algeria. Preliminary reports indicate that damaging unconfined vapor cloud explosions appear to have occurred. If so, this would be the first UVCE which has been reported in an LNG terminal (to the author's knowledge). Final reports have not been released, so there is admittedly some speculation involved here. That said, it appears to the author that damaging explosions did occur both in confined spaces and in unconfined spaces in the export terminal at Skikda. It is important to point out that since the releases are believed to have occurred in parts

[4] The author is aware of consideration being given to changing the specifications of the LNG that would be accepted by the proposed terminal. As stated earlier, this report has been prepared based on the descriptions made available from the SES Resource Report dated January 2004.

of the facility which would not have been handling LNG, but rather natural gas liquids, that the unconfined vapor cloud explosions experienced probably involved NGL. Nevertheless, particularly since the POLB will handle similar natural gas liquids, the recent experience in Algeria is highly relevant.

- The disaster which occurred on November 19, 1984, in San Juan Ixhuatepec (Mexico City), Mexico, is directly relevant to the consideration of the POLB LNG terminal, because the Mexico City facility provided for storage of quantities of NGL which are very similar to the quantities that could be stored at the NGL component of the POLB terminal. The Mexico City terminal, built for the distribution of LPG which came by pipeline from distant refineries, had an overall storage capacity of approximately 4,200,000 gallons of LPG in 6 large spherical tanks and 48 horizontal cylindrical tanks. The catastrophe started with the rupture, due to pumping overpressure, of an eight inch transfer line. The LPG thus released caught fire, causing fire impingement on one of the spherical tanks. The resulting cascading failure involved multiple unconfined vapor cloud explosions (UCVEs) accompanying the large fires which occurred. 574 people are reported to have been killed and more than 7,000 injured, of whom 144 later died in the hospital. Some 39,000 people were rendered homeless or were evacuated, and the terminal was destroyed.

2.2.7 Boiling Liquid Expanding Vapor Explosion (BLEVE) Hazards

The acronym BLEVE is short for “Boiling Liquid Expanding Vapor Explosion”. There have been a large number of devastating BLEVEs in the chemical process industry and in the transportation sector, including railroad and highway truck incidents. BLEVEs occur when a pressure vessel containing a flammable liquid is exposed to fire so that the metal comprising the containment loses strength and ruptures. When a vessel containing liquid under pressure is exposed to fire, the liquid heats up and the vapor pressure rises, increasing the pressure in the vessel. When this pressure reaches the set pressure of the pressure relief valve (PRV), the valve opens to relieve the pressure. The liquid level in the vessel falls as the vapor is released to the atmosphere. While the liquid is effective in cooling that part of the vessel wall which is in contact with it, those parts of the wall (above the liquid) that are exposed to vapor are not as effectively cooled. After a time, as metal which is not cooled by liquid is exposed to fire, the metal becomes hot and weakens and is subject to rupture. It is important to note that rupture can occur even though the pressure relief valve is operating correctly as designed. This is because a pressure vessel is designed to withstand the relief valve set pressure, but only at the design temperature conditions. If the metal is heated to higher temperature, it may lose strength sufficiently to rupture. Further, and most importantly to the consideration of the failure of LNG tanks to fire exposure, the pressure relief valves must be sized to allow relief of the vapor produced with fire exposure to the tank. I will return to this question when the vulnerability of LNG containments is considered.

Just as the conventional wisdom before about 1970 minimized the potential for explosion of unconfined LNG vapor clouds, that wisdom has also held that boiling liquid expanding vapor explosions of LNG containments are not possible. It appears that the conventional wisdom may have to be updated for BLEVEs of LNG as well.

An LNG road tanker exploded on 22 June 2002 near Tivissa, Catalonia (Spain), after the driver lost control on a downhill section of the C-44 road.[5] The tanker turned over, tipping onto its left side. Witnesses said that flames[6] appeared immediately between the cabin and the trailer, and after approximately 20 minutes, the tank exploded. There was a small explosion, then a strong hiss and then a much larger explosion. Immediately after the small explosion, the fire disappeared and a white cloud appeared. This cloud ignited immediately, giving rise to the larger explosion, a fireball. Assuming that all of the mass initially contained in the tank was involved in the fireball, approximately 12,700 gallons of LNG would have burned. Accepted mathematical modeling techniques suggest that the fireball diameter would have been about 500 feet, the height about 370 feet, and the duration approximately 12 seconds. These model predictions appear to be consistent with the facts that the fireball resulted in serious burns to two persons at a distance of 650 feet from the tanker. Major parts of the truck were projected to significant distances. The rear part of the tank, including the rear undercarriage of the truck, was ejected to a distance of 260 feet. A section of the front of the truck with maximum dimension of approximately 12 feet was projected more than 400 feet, and the motor and cabin covered a distance of more than 840 feet from the explosion.

[5] Planas-Cuchi, E., et.al, “Explosion of a road tanker containing liquefied natural gas”, Journal of Loss Prevention in the Process Industries, 17 (2004), pp 315-321.

[6] The photograph shows the jet fire from the tanker 2 minutes after the accident and approximately 18 min before the BLEVE. The author is not aware of any photographs of the fireball (but see footnote 7).

This LNG truck accident has been described in some detail because its occurrence suggests, if not demands, that renewed consideration be given to the potential for BLEVEs of LNG containers to occur. Perhaps most importantly, the road tanker was insulated with polyurethane insulation, and the early failure of the insulation would be expected to allow the container to more quickly reach temperatures giving rise to failure as well as allow heat transfer to the cargo which would significantly elevate the pressure in the tank beyond the ability of the PRV to relieve the greatly increased LNG vaporization. It is this mechanism, failure of the insulation followed by overpressure of the tank leading to rupture, which may have been exemplified in the Spanish road tanker explosion, that I have appealed to the Department of Homeland Security to consider as being applicable to LNG ships whose containers are insulated with foamed plastic insulation materials such as polystyrene and polyurethane[7].

There have been repeated incidents of BLEVEs of truck and rail containers of NGL, many having occurred in the Seventies and Eighties before the mechanism of the occurrence was understood. And, as was stated earlier, there have been devastating occurrences of BLEVEs in industrial storage and distribution facilities, perhaps most appropriately exemplified here by the disaster of November 19, 1984, in San Juan Ixhuatepec (Mexico City), Mexico. The Mexico City disaster is particularly relevant to the present considerations because the quantity of NGL stored in the Mexico City facility was similar to the quantity that could be stored in the POLB LNG terminal. Although the catastrophe started with the rupture of an eight inch transfer line, the first subsequent major failure is thought to have been a BLEVE of one of the NGL storage spheres, and the subsequent cascading failures involved multiple large BLEVEs.

[7] On July 5, 1973, in Kingman, AZ, a rail car containing approximately 10,000 gallons of propane began leaking during unloading, and the gas ignited. About a half hour later the tank BLEVE'd. The diameter of the fireball was approximately 400 feet, similar, if somewhat smaller, than the size predicted for the LNG BLEVE described in footnote 6. Note telephone poles for scaling and the railcar end being projected.

2.2.8 Special Hazards of LNG and NGL Spills on Water

There are special hazards of spills of LNG or NGL that could result from spills of either material on water, because, in addition to the (lesser) hazards of rapid phase transitions that could result from LNG spills considered earlier, it would be impracticable, if not impossible, to contain the spread of either of these liquid fuels on water. Consequently, there would be nothing to limit the size of the liquid pool that would result except the limiting amount of material spilled and the physical constraints which would limit its spread on the water. Since the size of the liquid fuel pool would determine the size (areal extent) of the fire, large spills on water could easily result in fires much larger than those which would be contained in the purpose-designed spill impoundment areas on land.[8]

[8] The photograph illustrates an LNG pool fire on water. Somewhat less than 10,000 gallons of LNG was spilled; the resulting fire is about 50 feet in diameter and 250 feet high. This test, conducted by the U.S. Coast Guard at China Lake, CA, in the Eighties, is also representative of the largest LNG pool fires that have been studied.

As will be described and justified in more detail subsequently in this report, there is now scientific consensus that rapid spillage of at least one half of a typical single LNG ship container, approximately 3,000,000 gallons, is a “credible event”, as it has been determined that it could be caused by an intentional (terrorist) act with means that are readily available to such groups. The fire from such a spill, particularly if it occurred onto water and was therefore uncontained, would be very large, perhaps up to a half-mile in diameter, or larger if more of the containment system failed. We have no experience with such fires, but we do know that they could not be extinguished and would just have to burn themselves out, and the radiant heat extending outward from the fires edge could ignite combustible materials as well as cause serious burns to people at substantial distances from the fire’s edge. The distances from such fires to which harm to the public, as well as damage to infrastructure, could extend will be a primary focus of this report.

Furthermore, although it is considered highly likely (but we do not know enough to say impossible) that early, if not immediate, ignition of the gas air mixtures above such a spill would occur as a result of the violent circumstances (as in an allision or collision of a ship or a terrorist attack) that would be expected to accompany such a major release, it is imperative that the extents of flammable vapor cloud travel that might result from major spills of LNG onto water (which are most likely to occur from the ship) be considered in the assessment of hazards that could result at the POLB LNG terminal.

CHAPTER 3

ADEQUACY OF CURRENT REGULATIONS TO PROVIDE FOR PUBLIC SAFETY

This part of my report gives my answer to the question: *To what extent do present U.S. regulations that govern LNG terminal siting adequately protect the public from the consequences of LNG releases that could occur?*

Although U.S. Regulations currently require enforcement of <u>some</u> safety exclusion zones intended for the protection of the public (by prohibiting their presence therein), I believe they fall seriously short of achieving the intended objective:

- The regulations were promulgated in the early Eighties largely as a result of concerns for public safety that arose in the Seventies. Since there was no rush to build additional LNG import terminals until about the year 2000, the regulations were largely unused for import terminal siting. As a result, the regulations did not, and still do not, give serious consideration to the terrorist threat that began in this country September 11, 2001. Instead, the regulation method and approach relied on, and still relies on, consideration only of accidental occurrences that could affect the public. Hence, the current regulations do not effectively address the many serious questions posed by the present requirement to consider events that could be caused by malicious intent. Nor is sufficient attention being paid to the reality that malicious intent changes the whole safety picture. We no longer have the option to just "better" manage the risks involved so as to reduce the probability of occurrence of accidents to an acceptable level. The siting in an urban area of an LNG terminal, with its requirements to concentrate immense quantities of hazardous materials, takes on a new dimension. Unfortunately, the process has outrun the development of the regulations to deal with it, and the present regulations fail to address this most important new paradigm.

- Perhaps most importantly, in consideration of the post 9/11 threat, there is presently no requirement, much less enforcement, of exclusion zones to protect the public from LNG spills which could occur from the ships that serve the import terminal. The failure to provide for the protection of the public and surrounding infrastructure from major releases of LNG that could occur from the ships serving the facility must be considered all the more important now as a result of recent government sponsored reports, for which there is now scientific consensus, that indicate that the danger zones extending from large, but credible, spills on water are likely to pose greater threats than would either accidental or terrorist caused releases from the land part of the terminal.

3.1 49 CFR 193 LNG Terminal Siting Provisions for Public Safety

The regulation that specifies requirements for siting LNG import terminals in the United States is 49 CFR 193, entitled *Liquefied natural gas facilities: Federal standards*.

Part 193 -- *Liquefied natural gas facilities: Federal standards* contains numerous sections describing requirements designed to provide for safe operation of an LNG import terminal. However, most of these sections are directed to the attainment of safe operation of the plant, and therefore they do not directly address the public safety issue. There are two sections of the regulation that directly address requirements to provide for safety of the public (offsite):

193.2057 *Thermal Radiation Protection*,

and

193.2059 *Flammable vapor dispersion protection*.

It is noted that the three other LNG hazards described earlier; toxicity, cryogenic ("cold burn"), and rapid phase transition, are not addressed, as these three potential hazards are not expected to affect the public offsite. Explosion hazards (not covered by the regulation) will be considered herein.

Before proceeding to the description of Sections 193.2057 and 193.2059, and to the question of their adequacy to provide protection to the public, I believe it will be helpful to briefly summarize the development of these two sections of the regulation.

During the Seventies, when the four presently operating LNG facilities were constructed in the United States, 49 CFR 193 had not yet been promulgated. The applications for certification of the terminals that were built in Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana, were decided largely based on guidance contained in industry consensus standards, notably NFPA (National Fire Protection Agency) 59A – *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*.

However, as a result of public concerns that arose during the Seventies about LNG terminal siting safety issues, notably those that arose in California regarding the proposals to site terminals at Los Angeles, Oxnard, and Point Conception, Congress mandated a research program on LNG safety, and authorized an expenditure of approximately $40,000,000 (in 1977 dollars) on LNG safety studies. That research program carried out basic LNG safety research directed to development of methods to define more accurately and realistically the consequences that could result from major spills of LNG. The research effort was directed to three hazards which were considered highest priority;

- liquid pool fires,
- vapor cloud fires, and
- vapor cloud explosions.

Following completion of these research programs, which still constitute much if not most of the research results and data relating to LNG spill consequences that are available in the public domain, 49 CFR 193 was promulgated - in the early Eighties.

I was called upon from time to time for advice by persons in the U.S. Department of Transportation who were preparing the draft regulations that evolved into 49 CFR 193, primarily in the area of my principal expertise, LNG vapor dispersion. My association (with DOT, at that time) was with Mr. Walter Dennis. Walter Dennis was actively involved in the drafting of the sections of 49 CFR 193 identified above (Sections 2057 and 2059), and I had several conversations with him regarding these sections of the regulation, particularly regarding the selection and application of methods for determining vapor dispersion distances. I believe that Walter Dennis was the person primarily responsible for developing Sections 193.2057 and 2059. This is important to the present discussion because Mr. Dennis subsequently advised industry (at their request) regarding the methods to be followed in the determination of exclusion zones required by the regulation. Walter Dennis died (in the late Eighties, I believe) when interest in LNG importation was languishing. I believe that his advice regarding the determination of vapor cloud exclusion zones has been used improperly so as to downplay the severity of the hazards which the regulation is designed to protect against.

(At least partly) as a result, there remains confusion even today about the correct determination of vapor cloud dispersion exclusion zones for spills of LNG which could occur into impoundments on the land terminal. I have prepared reports for the City of Fall River, MA, and I have filed testimony with FERC as well, which describe errors that I believe were made in the preparation of the Draft Environmental Impact Statement for the Weaver's Cove Project proposed to be sited in the Taunton River at Fall River.

With that background, I return to consideration of 49 CFR 193. When 49 CFR 193 was promulgated in the Eighties, it provided for the determination of *exclusions zones* for *vapor dispersion* and *thermal radiation*. The term *exclusion zone* is defined in the current regulation:

"Exclusion zone means an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with Sec. 193.2057 and Sec. 193.2059 for as long as the facility is in operation."

This definition is critically important because it follows that the intent of the regulation is that the *consequences* of vapor cloud dispersion and fire radiation scenarios must be specified by determination of the distances to which each of these hazards would extend from the spill, and once those distances are determined, the resulting exclusion zones must be controlled by the owner of the facility or the government. Thus the regulation provides for the prevention of members of the public from occupying the areas included by the exclusion zones, and therefore prevents them from being exposed to the associated hazards. Importantly, no consideration is given to the probability of such hazards being realized (the regulation is *consequence* driven, i.e. it gives no consideration to the probability of the occurrence), it simply defines the extents of the *exclusion zones* which are enforced to ensure that the public is not exposed to danger. *As I have stated earlier, I believe that such a consequence driven requirement for the establishment of exclusion zones to protect the public is all the more appropriate today in view of the potential* *severity of the terrorist threat, for which historical accident experience, however good, provides little assurance to the public.*

It is noted here that there is no mention in 49 CFR 193 of explosions, either vapor cloud explosions (confined or unconfined) or boiling liquid expanding vapor explosions. I will return to this important omission later.

3.1.1 Exclusion Zones for LNG Pool Fires

Section 193.2057 of the Federal Standard is excerpted below.

Sec. 193.2057 Thermal radiation protection.

Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with section 2-2.3.1 of ANSI/NFPA 59A with the following exceptions:

(a) The thermal radiation distances shall be calculated using Gas Research Institute's (GRI) report GRI-89/0176, which is also available as the "LNGFIRE III" computer model produced by GRI. The use of other alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted subject to the Administrator's approval.

(b) In calculating exclusion distances, the wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.

(c) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than five percent of the time based on recorded data for the area.

Amdt. 193-17, 65 FR 10958, Mar. 1, 2000]

It is critically important to note here that the determination of exclusion zones for LNG pool fires requires specification of the criterion to be used to define the extent of the thermal flux hazard, i.e., a criteria for determining how far away from the fire must the public be to be protected. 49 CFR 193 presently requires that thermal exclusion zones be defined by the (mathematical model) prediction of the distance to which a person, at ground level, would be exposed to thermal radiation flux of 5 KW/m^2 (~1600 $Btu/hr/ft^2$). This thermal flux has been determined to have the potential to cause second degree burns to unprotected skin in approximately 30 seconds.

But, as I have previously testified to FERC, I believe that the criterion of a 5 KW/m^2 flux level merits further consideration, because exposure at this intensity to persons could result in serious burns within time periods which would not be sufficient for evacuation or escape. Further, although fire fighting personnel equipped with protective gear could work in such an environment for considerable time, they would not be able to provide evacuation or removal of unprotected persons in time to prevent injury. It is known that the flux level would have to be reduced to about 1.5 KW/m^2 before unprotected persons could be exposed continuously without thermal radiation injury. Consequently, I believe that serious consideration should be given to defining exclusion zones to protect the public from thermal radiation hazards using such a lower (~1.5 KW/m^2) thermal radiation flux criterion. However, whether or not DOT defines the exclusion zone using such a lower thermal radiation flux criterion, I believe that FERC should use the lower thermal flux criteria in order to protect the public from such very large fires. It is very important to recognize that a policy which prevents public presence only where there would be exposure to 5 KW/m^2 or greater is not consistent with the public interest, because the public could receive serious injuries at lower flux levels if exposed for longer time periods (including time periods that would still be insufficient to provide for sheltering or evacuation). That is why I have suggested that serious consideration of the lower value of 1.5 KW/m^2 as the "safety" criterion – as this value is widely recognized as being the <u>highest</u> value of thermal radiation exposure from which the public would not receive serious injury even if exposed for longer time periods."

For the determination of thermal radiation exclusion zones for the land side of the facility, the credible spill scenario must be defined for input to the LNGFIRE III model. The scenario then is defined by specifying the dimensions of the impoundment area that will contain the spill, and then specifying the rate and total amount of LNG that is spilled. Two types of spill scenarios are possible:

- Spillage from the LNG storage tank

and

- Spillage from a part of the piping system external to the storage tank.

<u>Spillage from the LNG Storage tank</u>

It is my understanding that the storage tank design proposed for the Long Beach Long Beach facility is a Total Containment design, which means essentially that the inner tank in contact with the LNG is surrounded by a prestressed concrete outer tank wall and covered with a similarly constructed roof. To my knowledge, no tanks of the this type have so far been constructed in the continental United States (the Penuelas, Puerto Rico, tank has a prestressed concrete outer tank, but I do not believe it has a concrete roof), but such tanks are currently being proposed for several other locations. It is my understanding that there remain some questions about the procedures to be followed for such installations, even questions relating to the lack of "definitions" for the various tank systems that are being considered. Nevertheless, 49 CFR 193 appears to have been interpreted by DOT, at least in the case of the DEIS and EIS's prepared for the Weaver's Cove terminal in Fall River, MA, in such a manner that the regulation does not require consideration of LNG spills that would penetrate the outer containment wall. It is my understanding, based on DEIS's that have been produced for terminals with similar tank design proposals, that the thermal radiation zones for fires associated with spills from the inner tank are (therefore) to be determined by assuming that the spilled LNG would be *contained* by the concrete outer wall. As a result, the fire scenario envisioned is an elevated, or "tank-top", fire with the diameter (size) of the fire determined by the diameter of the outer concrete tank. For such determinations, I believe that application of the prescribed method (LNGFIRE III) is adequate.

However, there remains a question about the validity of the assumption that failure of the outer concrete wall is incredible. Although I agree that such a failure due to accident would seem to be extremely remote, I cannot agree that such an event is impossible for a terrorist to achieve – witness our tragic experience on 9/11 when two large airliners were highjacked and flown into the World Trade Towers with devastating results. To my knowledge no analyses have been made available to the public which address the possibility of complete failure of a "total containment" LNG storage tank. I will return to the consideration of "worst case" events after consideration of the current requirements for determination of exclusion zones.

Spillage from the Piping System

Here, also, the regulations prescribe detail that cannot be adequately described here. However, it is my understanding that the intent of the regulation is to prescribe the credible spill events (for determination of exclusion zones) by identifying the portions of the pipeline systems that carry LNG at the largest rates in the facility, and then to assume a guillotine break in said line with flow at the maximum rate maintained for a period of ten minutes. It appears that negotiations with DOT in the past have in some cases resulted in approval of procedures which will ensure limiting the duration of flow (by automatic shut-off systems) to shorter periods, but I assume here the requirement for a ten-minute spill duration.

In either case, LNGFIRE III application is straightforward, since the fire size is prescribed by the outer boundary of the area (impoundment) into which the spill occurs. In summary, I believe the application of LNGFIRE III, to LNG pool fires contained in liquid impoundment areas, adequately describes the thermal radiation hazard for the purpose of determining exclusion zones to protect the public.

3.1.2 Exclusion Zones for Vapor Cloud Dispersion

Section 193.2059 of the Federal Standard is excerpted below.

Sec. 193.2059 Flammable vapor-gas dispersion protection.

Each LNG container and LNG transfer system must have a dispersion exclusion zone in accordance with section 2-2.3.2 of ANSI/NFPA 59A with the following exceptions:

(a) Flammable vapor-gas dispersion distances must be determined in accordance with the model described in the Gas Research Institute report GRI-89/0242, ``LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model." Alternatively, in order to account for additional cloud dilution which may be caused by the complex flow patterns induced by tank and dike structure, dispersion distances may be calculated in accordance with the model described in the Gas Research Institute report GRI 96/0396.5, ``Evaluation of Mitigation Methods for Accidental LNG Releases. Volume 5: Using FEM3A for LNG Accident Consequence Analyses". The use of alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted, subject to the Administrator's approval.

(b) The following dispersion parameters must be used in computing dispersion distances:

(1) Average gas concentration in air = 2.5 percent.[9]

(2) Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on figures maintained by National Weather Service of the U.S. Department of Commerce, or as an alternative where the model used gives longer distances at lower wind speeds, Atmospheric Stability (Pasquill Class) F, wind speed = 4.5 miles per hour (2.01 meters/sec) at reference height of 10 meters, relative humidity = 50.0 percent, and atmospheric temperature = average in the region.

(3) The elevation for contour (receptor) output H = 0.5 meters.

(4) A surface roughness factor of 0.03 meters shall be used. Higher values for the roughness factor may be used if it can be shown that the terrain both upwind and downwind of the vapor cloud has dense vegetation and that the vapor cloud height is more than ten times the height of the obstacles encountered by the vapor cloud.

(c) The design spill shall be determined in accordance with section 2-2.3.3 of ANSI/NFPA 59A.

[Amdt. 193-17, 65 FR 10959, Mar. 1, 2000]

Again, it is important to note that the DEGADIS and FEM3A model(s) for calculating the exclusion zones for vapor cloud dispersion are *prescribed*. The DEGADIS model was promulgated in the regulation in an amendment dated in the early Nineties, and the

[9]The 2.5 percent concentration represents one half the lower flammable limit concentration of methane (5%). This concentration level is intended to define the cloud average concentration at a point which would prevent the presence of flammable (greater than or equal to 5 %) “pockets” of gas which could be ignited. Hence this concentration level is used as the criterion for delineating the hazard distance.

(alternate) FEM3A model was promulgated in the regulation in the amendment dated Mar. 1, 2000. I am the co-author, with Dr. Tom Spicer, of the DEGADIS model, and Dr. Spicer and I directed the research program sponsored by GRI (since about 1985) to validate a computational fluid dynamics model (FEM3A was ultimately selected, based on consideration of several candidate models) for LNG vapor dispersion application. I support the use of the DEGADIS and FEM3A models. Based on my knowledge of the models and my review of the development of both, I believe that, together, they incorporate reasonably the latest information obtained in the federally sponsored large scale LNG field test programs conducted by the Coast Guard at China Lake, CA, and at the Liquefied Gaseous Fuels Spill Test Facility (LGFSTF) located near Mercury, Nevada, in the Seventies and Eighties, as well as the results of other research programs that have been conducted, principally in the Chemical Hazards Research Center Wind Tunnel at the University of Arkansas.

The DEGADIS model is limited to application to dispersion of vapor clouds (including LNG vapor clouds) resulting from spills onto a flat surface (ground or water) with dispersion over flat, obstacle-free terrain. FEM3A was developed in a followup effort (to DEGADIS) to provide a mathematical model applicable to the determination of the effects on dispersion of manmade obstacles (such as tanks, dikes, or process equipment and structures) and/or significant terrain features. I believe that these two models, correctly applied for the situations for which they are designed, are adequate tools for determining vapor cloud exclusion zones which will ensure public safety. And, similarly to the previous discussion on thermal radiation exclusion zones, I believe that the application of these models, *respecting the limitations of each*, is relatively straightforward for the determination of vapor cloud exclusion zones extending from spills bounded by containment structures (dikes and impoundments) on land.

It is clearly the intent of 49 CFR 193 that enforcement of a vapor cloud dispersion protection exclusion zone implies that the area included be controlled by the facility operator or an agency of the government. It is also clear that the intent of the regulation is to provide for the enforcement of vapor cloud dispersion protection zones as the method for ensuring the safety of the public, since such exclusion zones clearly prohibit the presence of the public therein.

For the determination of vapor cloud dispersion exclusion zones for the land side of the facility, the credible spill scenario must be defined for input to either the DEGADIS model or the FEM3A model. The scenario is defined by specifying the dimensions of the impoundment area that will contain the spill, and then specifying the rate and total amount of LNG that is spilled. Again, two types of spill scenarios are possible:

- Spillage from the LNG storage tank

and

- Spillage from a part of the piping system external to the storage tank.

Spillage from the LNG Storage tank

As stated before, it is my understanding that the storage tank design proposed for the Long Beach Long Beach facility is a Total Containment design, which means essentially that the inner tank in contact with the LNG is surrounded by a prestressed concrete outer tank wall.

Further, it is my understanding, based on DEIS's that have been produced for terminals with similar tank design proposals, that the vapor cloud dispersion exclusion zones associated with spills from the inner tank are to be determined by assuming that the spilled LNG would be *contained* by the concrete outer wall. As a result the vapor cloud dispersion scenario envisioned is an elevated, "tank-top" vapor release, with the diameter (size) of the release determined by the diameter of the outer concrete tank. For such determinations, I believe that application of the FEM3A method, although untested for such use, is appropriate. However, the DEGADIS model was designed for applications to *ground level* releases, and I cannot recommend it to describe the tank-top release scenario.

I do note that vapor releases from the top of the tank would be expected to pose significantly less hazard to the public than would equivalent releases at ground level, particularly if accompanied by high wind conditions.

However, as in the case of the determination of fire radiation exclusion zones, there remains a question about the validity of the assumption that failure of the outer concrete wall is incredible, as (to my knowledge) no analyses have been made available to the public which address the possibility of complete failure of a "total containment" LNG storage tank. I will return to the consideration of "worst case" events after consideration of the current requirements for determination of exclusion zones.

Spillage from the Piping System

Here, also, the regulations prescribe detail that cannot be adequately described here. However I believe that the intent of the regulation was, and remains, to prescribe the credible spill events (for determination of exclusion zones) by identifying the portions of the LNG transfer systems (pipes) that carry LNG at the largest rates in the facility, and then to assume a guillotine break in said (pipe)line with flow at the maximum rate maintained for a period of ten minutes. I do note here that DOT has considered, and approved, procedures which would ensure limiting the duration of flow (by automatic shut-off systems) to shorter periods, but here I assume the requirement for a ten-minute spill duration.

For such spillage into an impounded (or diked) area, the containment afforded limits the liquid (LNG) spreading that can occur, and therefore effectively determines the area extent of the source of vapor (evolving from the spilled LNG).

But, there remain questions even about the requirements for specification of the leak rates that have not been resolved. I have filed testimony with FERC which describes my complaints that the present specification of "accidental leakage rate" design spills by NFPA 59A (which has been incorporated in 49 CFR 193 since the year 2000, effectively replacing the previous requirement for 10 minute full flow spills from the largest transfer line in the facility), have the effect of reducing the requirement for consideration of these (larger spills) that were the intent of the regulation - with the final result that the downwind vapor hazard is downplayed. FERC has not even been consistent in this regard, since they have given approval for submissions from facility applicants that contained transfer line spills with volumes ranging from 28,900 gallons (3-inch line break) all the way to 812,000 gallons (guillotine rupture of ship unloading line).

But, however the spill rate and volume is determined, the vapor cloud dispersion protection exclusion zone determination is not as straightforward as that for the determination of the thermal radiation protection exclusion zone, because:

- DEGADIS was designed to predict dispersion from spills on a flat surface, with dispersion proceeding on a flat surface, *in the absence of significant terrain features or manmade structures that would obstruct the wind or gas cloud flow*. A dike (or the vertical walls of an impoundment) designed to contain the spilled LNG (liquid) causes "holdup" of the gas until the gas overflows the impounded volume. The DEGADIS model does not allow direct accounting for the effect of the vapor "holdup" that occurs within the impounded/diked area. Although provisional methods have been suggested in the past for using DEGADIS under such conditions, such methods have been demonstrated to be in error, as will be discussed subsequently. It is now clear that utilization of certain methods provisionally suggested in the Eighties (for determining gas "holdup") can lead to serious errors in the determination of vapor cloud dispersion protection exclusion zones.

- Research conducted during the last two decades has resulted in the Department of Transportation's acceptance and approval of the use of the FEM3A vapor dispersion model. The FEM3A model *provides for prediction of the holdup that occurs in an impoundment area* as well as for other effects of obstacles or terrain features on dispersion of an LNG vapor cloud.

3.2 The Potentials for Unconfined Vapor Cloud Explosions and Boiling Liquid Expanding Vapor Explosions are not Addressed

Unconfined Vapor Cloud Explosion Hazard

The concern for the potential of unconfined vapor cloud explosion hazards at the proposed LNG terminal in Long Beach is directly related to the composition of the LNG that will be imported to the facility. It is anticipated that significant quantities of "hot gas", i.e., LNG containing significant quantities of hydrocarbons heavier than methane will be received at the terminal., and the plant is being designed to remove such heavy components (ethane, propane, etc.) for marketing and distribution from the facility.

Since it does not appear practicable to remove the heavier components of the gas *as it is being unloaded from the tanker into the storage tanks*, it is presumed that the "hot gas" NGL components will have to be stored, at least temporarily, prior to their distribution off site. Consequently, it is presumed that there could be significant quantities of LNG containing heavier hydrocarbons such as ethane, propane, etc., that will be stored and handled in the facility.

The problem of explosion potential of LNG vapor clouds has been studied. I quote directly from U.S. Coast Guard Report CG-M-03-80 entitled *U.S. Coast Guard Liquefied Natural Gas Research at China Lake*, dated January 1, 1980 (pages 12-13):

"Since unconfined vapor clouds composed of LPG have detonated after tank car and pipeline accidents, the next group of high explosive direct initiator tests involved the system methane-propane stoichiometric in air, always using a 1.35 kg Composition B initiator in a 5 m hemisphere.

….

The test series was run in the sequence 90% methane-10% propane, 57.6%-42.4%, 76.8%-23.2%, 81.6%-18.4%, and 86.4%-13.6%. Only methane concentrations above 81.6% failed to produce a vapor cloud detonation. The velocity of the fuel-air detonation wave was 1800 m/s and the maximum pressure was 15.5 bars in the 81.6%-18.4% test. Clearly, for the 1.35 kg initiator, the critical percentage of propane for the methane-propane-air detonation is between 13.6% and 18.4% propane; financial restrictions prevented the determination of critical concentrations for other initiator sizes. Theory suggests that the use of propane as a sensitizer is representative of all hydrocarbons heavier than methane. The 13.6% sensitizer concentration has special consideration as the commercial LNG being imported into the U.S. east coast has about 14% higher hydrocarbons."

Based on this report, which to my knowledge has not been called into question, it is clear that there is a potential unconfined vapor cloud explosion (UVCE) hazard associated with the errant release of LNG containing heavier (than methane) hydrocarbons in amounts in the range 13 -18% (and higher).

Furthermore, it is important to note that the explosions described in the Coast Guard Report were gas phase *detonations*, which means that the flame (reaction front) speeds were greater than the speed of sound in the unburned gas mixture. It is now well understood that damaging overpressures can occur in unconfined vapor cloud explosions even when flame speeds are well below those which result in detonations. The bottom line here is that LNG with concentrations above the range 13-18% has been shown to have the potential to *detonate when unconfined*, and there is consequently a very real potential for UVCE's to occur with damaging overpressures when such (unconfined) gas-air mixtures are ignited.

Consequently, although the present regulations do not require consideration of the UVCE hazard associated with vapor clouds that might result from spills of LNG, consideration of the UVCE hazard is relevant for the proposed Sound Energy Solutions terminal *if it is to import "hot gas" that may have concentrations of heavier components in the range above approximately 13-18%.*

Finally, it is noted that enrichment in higher boiling point components of the liquid remaining on the water as the LNG vaporizes can lead to vapor cloud concentrations that pose a UVCE hazard, even if the concentration of the heavies in the liquid initially spilled do not.

Boiling Liquid Expanding Vapor Explosions

If the decision is made to install NGL storage at the facility, consideration must be given to the potential for BLEVEs to occur in the event that the storage tanks are exposed to fire. The potential for NGL BLEVEs to threaten either public safety or infrastructure to distances greater than are already anticipated to be credible for large LNG pool fire or vapor cloud dispersion hazards appears to be low; however there is very real potential for severe mechanical damage (by explosive force or due to ejected missile impact) to the primary LNG storage facilities (or a ship at the jetty) that could cause cascading events that would worsen the situation.

In view of the recent apparent occurrence of a BLEVE of an LNG tank truck in Spain, the potential for BLEVEs of the trucks serving the facility, as well as LNG storage tanks, cannot be ruled out. However, the potential for BLEVE-like explosions appear to be much more likely from the ship containers than from the more heavily constructed and more fire-resistively insulated LNG storage tanks on land.

3.3 There is a Critical Need for Exclusion Zones for LNG Spills on Water

The potential for catastrophic releases from LNG carriers that service an LNG import terminal are acknowledged by FERC in several Draft and Final Environmental Impact Statements, including both for the Weaver's Cove Project in Fall River, MA. FERC has consistently stated that such catastrophic releases would be most likely caused by terrorist attack, and FERC's own analyses have shown that the consequences of such ship-side releases that have been identified tentatively as "credible" are far greater than the hazards posed by the land-side LNG spill scenarios. Nevertheless, the Commission continues to dismiss these hazards on the grounds that the threat of such events (large pool fires on water, or large vapor cloud formation following a spill on water) can be "managed".

I cannot support FERC's statement (from the Weaver's Cove and other Impact Statements) that "While the risks associated with the transportation of any hazardous cargo can never be entirely eliminated, they can be managed". In my opinion, this statement, with no justification provided, does nothing to provide the public confidence in FERC's ability to "manage" these risks. Indeed, I believe that it downplays the importance of the principal threat to public safety that is associated with the operation of any LNG import terminal – a terrorist attack that could result in catastrophic spills of LNG onto water.

I believe my recent testimony before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, provides adequate explanation of my view on this matter. Although the inclusion here of that testimony is repetitive of my earlier comments, I believe such repetition is warranted:

Testimony of Dr. Jerry Havens
Before the Congressional Subcommittee on Energy Policy,
Natural Resources and Regulatory Affairs
Tuesday, June 22, 2004

Mr. Chairman and Members of the Committee: My name is Jerry Havens. I am a Distinguished Professor of Chemical Engineering at the University of Arkansas. I appreciate this opportunity to address this hearing on Federal and State Roles in LNG Import Terminal and Deepwater Port Siting. I am speaking here today as a citizen-scientist, and not as an agent of my University.

I have for some thirty years been studying methods for assessing the potential consequences of major accidental releases of LNG. My remarks here today are about the estimation of the extents of danger to the public around such spills.

I believe that the potential danger to the public from LNG spills is mainly from the very large fires that could occur. I want to emphasize that I am talking about fires resulting from the spillage of several millions of gallons of LNG – a single tank on a typical LNG carrier contains six or more million gallons of liquefied natural gas. The fire from such a spill, if it occurred onto water and was therefore uncontained, would be very large, perhaps up to a half-mile in diameter, or larger if more of the containment system failed. We have no experience with fires this large, but we do know that they could not be extinguished, they would just have to burn themselves out, and the radiant heat extending outward from the fires edge could cause serious burns to people even at larger distances.

There are two ways that very large fires can follow a major LNG spill. If LNG is spilled it will rapidly evaporate and the vapors will mix with air to form a mixture which will burn in the concentration range of approximately 5% to 15% LNG vapor. Such mixtures of LNG vapor and air will inevitably form when LNG is spilled, and if an ignition source such as an open flame or spark are present, as would be highly likely to accompany the violent circumstances that would cause a major release, a large pool fire will result. However, if no ignition sources are present in the flammable gas mixture a vapor cloud will result, and the cloud will spread downwind from the spill until it either contacts an ignition source or becomes diluted below its flammable concentration - it will then disperse harmlessly.

The maximum distances of the danger zones extending from a pool fire or a flammable vapor cloud determine the zones which would endanger the public. It is the estimation of these distances, which are identified in 49 CFR 193 as pool fire radiation and vapor cloud dispersion exclusion zones, that I want to inform you about, because such exclusion zones are required in order to ensure that people are not exposed to danger if such a fire should occur, and such requirements determine the effectiveness of the LNG siting regulations to provide for public safety.

I first began studying the prediction with mathematical models of vapor cloud travel distances in the 1970's, when as this Committee knows, the first wave of interest in LNG importation arrived in the United States. I am privileged to have had an important role in the development of the current regulatory requirements for determining vapor cloud exclusion zones to support requests to FERC for LNG terminal siting. Both of the computer models currently required by 49 CFR 193 for calculating vapor cloud exclusion distances were the result of developments by my Associates and I at the University of Arkansas. I have also followed closely and have been involved in, if less directly, the development of the methods required by 49 CFR 193 for determining pool fire radiation exclusion zones.

In my opinion the current requirements in 49 CFR 193 for determining both pool fire radiation and vapor cloud dispersion exclusion zones around LNG terminals are based on good science, and they are adequate for their purpose. Indeed, the present regulations are the result of considerably more research on LNG safety than has been performed for many other hazardous materials that are routinely transported and stored in very large quantity. Furthermore, I believe it is important to emphasize that the hazards associated with LNG, aside from the localized dangers involved with handling any cryogenic fluid, are neither unique nor extreme when compared with other hazardous materials handled in bulk. The potential dangers we are discussing today are brought into the present focus because of the enormous amount of energy that must necessarily be concentrated to enable economical transport of liquefied natural gas across the world's oceans.

However, the suitability of the methods required by the regulations for determining exclusion zone distances is not in serious dispute. The problem lies in the specification of the LNG spill scenarios that must be considered.

Current U.S. regulations require that exclusion zones be calculated for spills in the land-based portion of an LNG import terminal only – the regulations do not currently apply to spills that might occur from the LNG vessel onto water.

Because spills on land are subject to a variety of control measures to limit the area extent of the spill, such as dikes or impoundment systems, exclusion zones in support of requests for siting land-based LNG terminals are typically, in my experience, less than one thousand feet. However, if exclusion zones were required to protect the public from LNG spills onto water from an LNG vessel at the jetty or in route to or from the terminal, there is good scientific consensus that the fire radiation exclusion zones could extend to a mile *or more if the entire contents of a single tank were rapidly spilled, and the vapor cloud dispersion zone could extend for a similar spill to several miles. Obviously, if the regulations were applied to the determination of exclusion zones to protect the public from LNG tanker spills onto water, it would have a very important effect on siting decisions. It seems clear to me that such consideration would raise very serious concerns about the siting of LNG terminals where people within the exclusion zone distances would be endangered. It is very sobering to me to realize that the ongoing LNG siting debate regarding public safety comes down to this, and I sincerely hope that those responsible for protecting the public recognize and seriously consider this very important question.*

Since 911 we no longer have the luxury of considering only means for reducing the probability of accidents to a level that justifies the attendant risk. I believe that it is imperative that the dangers to the public from possible releases from a LNG carrier onto water be considered in the siting of LNG terminals in our country.

I must also tell you that I am very concerned that spills from LNG vessels caused by terrorist attack might not be limited to the partial contents of a single tank on the vessel, as is widely assumed. Because of those concerns, I wrote to the Secretary of Homeland Security in late February to urge the Department to consider the vulnerability of LNG carriers to terrorist attacks as part of their deliberations on LNG terminal siting. Because some of the matters that I believed worthy of consideration are sensitive, I do not think it is appropriate to discuss them in detail here, but I will try as best I can to address any questions you may have about this subject. I am very disappointed that I have not received any response from the Department of Homeland Security regarding my concerns.

Thank you, that concludes my comments.

I stand by this statement, and I believe it is particularly relevant to the consideration of siting the Sound Energy Solutions LNG Project in Long Beach Harbor.

Today, although the science community has acknowledged the need for additional experimental data that can be used to address some uncertainties which remain in the extrapolation of consequence distances from the approximately 10,000 gallon spill range that has been studied to the approximately 10,000,000 gallon range that has been determined to be credible to result from a terrorist attack on an LNG ship, it is clear that there is scientific (and government) consensus that methods which have recently been evaluated by the ABS Group for FERC and by the Sandia National Laboratory for the Department of Energy are suitable for the estimation of the extent of the thermal radiation or vapor cloud dispersion hazard distances that would extend from major releases of LNG onto water in the Port of Long Beach.

It is not necessary to repeat in detail the findings of either the ABS Group or Sandia Lab reports, both of which are attached as exhibits to this report. I will just summarize my reading of the conclusions of both reports which I believe are germane to the consideration of the proposed LNG terminal in the POLB.

The ABS Group and Sandia Lab reports, which appear to be now largely accepted by all of the regulatory agencies involved, including the Coast Guard, as being the best current guidance on these matters, emphasize for their extensive analyses of the consequences of marine spills just one (size) spill scenario. That is the spillage onto water of 12,500 cubic meters LNG – this figure being representative of approximately one half of a single tank on a typical LNG ship. The choice of spillage of half a tank (rather than a full tank) appears to be the result of the reports' authors' consideration of the extreme implausibility if not impossibility of the rapid spillage of the entire tank as an initial result of a terrorist attack.

Thermal Radiation from LNG Pool Fires on Water

Setting aside unnecessary precision, I believe that the ABS Group and Sandia Lab reports are in essential agreement that persons exposed to the thermal radiation from a pool fire burning on a 12,500 cubic meter (approximately 3,000,000 gallons) spill on water could receive second degree burns on unprotected skin in about 30 seconds at a distance of approximately one mile from the center of the spill.

I endorse these findings on thermal radiation consequences of LNG pool fires on waters from the ABSG and Sandia Reports, as far as they go.

But, as I have stated before, I do not think these predictions address sufficiently the real requirements to provide for public safety. I am convinced that the use of a thermal flux criterion that would result in second degree burns in 30 seconds is not appropriate for delineating distances necessary to ensure public safety. This (second degree burn criteria) is not sufficient because such exposure essentially ensures that serious burns will occur at that distance to persons who cannot gain shelter within 30 seconds. In addition to the obvious difficulties that would confront any able-bodied individual's attempt to flee from such a threat, there remain very serious questions about the almost certain inability of those less able to do so. As considerably lower thermal flux criteria (~1.5 KW/m^2) are prescribed in other national and international regulations designed to provide safe separation distances for the public from fires, I believe that FERC should consider such a lower thermal flux criteria, which could increase the distances prescribed in the ABSG and Sandia reports by as much as one and a half to two times, to ensure the public safety from such large LNG fires.

Finally, regarding calls for more research in this area, I have already stated that there are some important needs. It is my understanding that Sandia and others are considering the need for more large scale LNG fire testing. If such tests were conducted with appropriate scientific planning, and if such tests were conducted for the purpose of obtaining experimental data which could be used to verify mathematical modeling methods (as opposed to one-time "demonstration" tests), I would endorse them, as I feel that additional testing would be worthwhile to provide better means of predicting the consequences of very large fires that could follow massive LNG spillage onto water.

<u>LNG Vapor Cloud Dispersion from Spills on Water</u>

I here also endorse the estimates of LNG vapor cloud dispersion presented in the Sandia and ABS Group reports, which range, considering all of the uncertainties identified in the reports, between approximately two and three miles. I note that while I have reviewed and am in agreement with the methodology used by the ABS Group for making these estimates (they in part used DEGADIS, of which I am a co-author), the Sandia report estimates were reportedly obtained using a CFD model called VULCAN, which I have not had the opportunity to evaluate, and which to my knowledge has not been independently evaluated for such use. I believe that the estimate of two to three miles of flammable vapor cloud travel that could result from an unignited spill of one half of the LNG contained in a single containment is at once reasonable and sufficient for consideration of the consequences of such spills of LNG in the POLB.

<u>There is a Real Concern for Cascading Failures to Occur</u>

But, I believe that limiting our consideration of the potential consequences of a very large LNG release and fire on water to the <u>initial result</u> of a terrorist attack is not sufficient. That would be like ignoring the collapse of the Twin Towers, because their collapse was not the initial result of the attack. Lest I neglect the consideration due of the worst case consequences of large scale tanker spills, it is important to note that the Sandia report states unequivocably that cascading events that could result either from brittle fracture of structural steel on the ship (due to LNG contact with the steel) or failure of the vaporization of the cargo at rates exceeding the capability of the pressure relief valves, cannot be ruled out.

We know that foamed plastic insulation, widely used on LNG carriers, including ships with both of these tank types, would be highly susceptible to failure by melting or decomposition. It is a cardinal safety rule that the pressure limits on tanks carrying flammable or reactive materials not be exceeded, as such exceedance portends catastrophic rupture of the containment. Such a rupture could lead to the release of a full tank of roughly 6,000,000 gallons of LNG, as well as the release from multiple tanks. While, as has been stated, the Sandia report concludes that such cascading events would be very unlikely to involve more than three of the five tanks on a typical LNG carrier – for a total release of 18,000,000 gallons (or more from the larger carriers now proposed) compared to the 3,000,000 gallon release on which all the modeling has been based – the basis for the Sandia report's "optimism" in this regard is unexplained. Once cascading failures begin, I do not know what would stop the process from resulting in the total loss and burning of all of the LNG aboard the carrier.

CHAPTER 4

CONCLUSIONS

CONSEQUENCES OF CREDIBLE ACCIDENTS AND TERRORIST ACTIONS, AND CONSIDERATION OF WORST POSSIBLE CASES

The objective here is to specify, based on observations of historical and experimental data, and supported by science-based guidance regarding the possibility of occurrence of postulated scenarios, the distances from such credible events to which the public as well as important infrastructure could be in harm's way.

Such a *consequence assessment* is a two step process:

1. The credibility (meaning here, the consistency of the event's occurrence with natural laws which we know to control such processes) of the postulated event must be established. For example, we can respond quickly and certainly to statements that an LNG ship contains the equivalent of fifty or more Hiroshima-size atomic bombs (a literal truth) with a certainty, based on physical laws, that the energy contained in an LNG storage tank cannot be released in a time frame sufficiently short to allow a meaningful comparison with the effects of fifty nuclear weapons each with a nominal 20 kiloton explosive energy release. It just cannot happen. However, we cannot dismiss the hazard on that basis either; instead we must consider the physical limitations which determine the length of time during which that energy could be released (in this case, by fire) in order to objectively define the consequences which could result.

2. Starting with the defined credible event, it is then required to determine the distance to which the hazard would extend. This process typically requires specification of both the total amount (of the hazardous material, measured here as energy content) released and the time frame over which the release occurs. As is true of many of the arguments advanced in this report, this is really just application of common sense - a very small spill rate, even continued for a very long time, would not be expected to pose the fire hazard that would result from the more rapid release of the same amount of material. An objective quantitative determination of the (hazard) distance is also a two step process.

    a. First a criterion for damage must be selected. For the present case these criteria are; for fires, specification of the permissible level of thermal flux exposure; and for vapor clouds, specification of the concentration level below which the cloud does not pose a flammable hazard because it could not be ignited.

    b. Finally, as the scenario being considered often involves releases with magnitudes potentially much more damaging than have been experienced, we have to extrapolate our experience to determine an

> objective measure of the consequence that can be expected. The best, if not the only, tools we have for such extrapolations are physical (such as wind tunnel) or mathematical models.

Utilizing information summarized in Chapters 2 and 3 of this report, I will summarize what I believe to be the present state of information about the quantities (and rates of release) of liquefied energy fuels that could occur associated with the operation of the proposed LNG terminal in the POLB, as well as the consequences to the public and infrastructure that could result.

Accidents and Terrorist Actions

The current regulations, particularly regarding provisions for public safety, focus on the land based part of the terminal. There are specific requirements for liquid containment and impoundment systems that are designed to limit the spreading of LNG that might be released either from the LNG tanks themselves or from transfer lines in the facility. But such control and mitigation measures could not be effectively applied to releases that could occur from an LNG ship, either at the jetty or in transit thereto, because spills onto water could not be effectively contained, and these concerns appear to have spurred the government's completion of two recent reports that deal with the tanker safety issue.

Before moving to consideration of the potential for, and consequences of, large LNG spills on water, I think it important to state that, in contrast to the attention given to the potential for large spills on water, very little attention is presently given to the vulnerability of land storage tanks to terrorist attack, or even to the vulnerability of land storage tanks to natural events such as earthquakes and tsunamis, consideration of which would appear to be highly relevant for the proposed POLB terminal. I believe that the vulnerability of the land tanks to such accidental or terrorist caused events, as well as to natural events such as earthquakes and tsunamis, needs to be considered carefully in order to provide the public assurance that we understand the potential consequences of releases that could occur on land as well as we now know them for spills on water. Fortunately, we have much more complete information regarding LNG spills onto water.

The ABS Group and Sandia reports agree that the release of LNG in the amount of approximately 3,000,000 gallons (half of one typical LNG ship tank) is credible,

- in that such a release could result from accidental collisions between ships with sufficient momentum (mass and speed) to cause such a breach of containment, or
- that such a release could be caused by terrorists with means that are readily available to them.

Furthermore, the ABS Group and Sandia reports agree, within the precision required here, that a release of 3,000,000 gallons of LNG onto water could result in:

- Pool fires which would expose persons with unprotected skin to thermal fluxes that could cause second degree burn injury in approximately 30 seconds (5 KW/m^2) at a distance of approximately 1 mile.

- Flammable vapor clouds, if the spilled material were not ignited upon release, that could extend downwind to distances between 2 and 3 miles. It is assumed here that persons that were caught in such a fire as might occur if the flammable cloud were ignited would be seriously injured, if not killed.

The author is in essential agreement with these consequence estimates but believes the following modifications are required if they are to be used to ensure public safety:

- Since the thermal radiation flux criterion (5 KW/m^2) used by Sandia and the ABS Group could cause second degree burns in thirty seconds, it is not sufficiently protective of public safety; a lower value, approximately 1.5 KW/m^2, is recommended here. This value is already being used by other segments of the regulatory system, both nationally and internationally, based on its definition as the highest thermal flux to which an unprotected person can be continuously exposed without injury. If the 1.5 KW/m^2 criterion is used, it is anticipated that the distance of 1 mile (associated with the higher flux level) would be increased to between 1 ½ and 2 miles.

- As the Sandia Report states unequivocably that cascading failures of ship tanks cannot be ruled out and further states that in their opinion failures of as many as 3 tanks could occur, this scenario must be considered credible. As Sandia estimates that the hazard distance from this scenario could be extended by approximately one-third, the distance to the 1.5 KW/m^2 flux level would then be increased to approximately 2 ½ to 3 miles.

- The ABS Group's high-end estimates for the vapor cloud distance to the 2.5 % gas concentration level (based on releases from a 5 meter diameter hole in the containment) are approximately 3 miles. The Sandia estimates for the credible scenario analyzed are closer to 2 miles, but their calculations reflect the distance to the 5% gas concentration level rather than the 2.5% level which is accepted to represent the better criterion for vapor cloud travel distance that could pose a hazard to the public. Use of the lower flammable gas concentration criteria would be expected to extend the hazard distance to about 3 miles.

Based on this information, which is believed to be the best that is available - and is in general agreement with widely held views in the scientific community, a <u>minimum</u> distance is specified here for the extent to which the public could be exposed to injury from the initial release of approximately 3,000,000 gallons of LNG onto water at the POLB. It is approximately 3 miles.

<u>Consideration of Worst Possible Cases</u>

I am recommending a <u>minimum</u> 3 mile radius circle around the proposed terminal to demarcate the area in which events deemed credible could cause serious injury to the public. The <u>minimum</u> distance to demarcate expected damage to infrastructure would be of lesser extent, depending on the criterion selected for damage.

As I have stated that the danger zone around the tanker extends to the route of the tanker approach to the facility, I observe that exposure of the public from incidents of spillage onto the water from the ship appears to be greatest when the ship is at the terminal jetty, rather than during its approach, since the terminal appears to be closer to populated areas than is any segment of its route to the terminal. Exposure of port infrastructure during the approach, based on my observation of the aerial view, would seem to be similarly concentrated at the terminal site, but such a conclusion does not consider any special hazards or vulnerabilities at different locations in the port. Estimation of the consequences to the POLB of a large release of LNG in the port must consider the wide variety of flammable and other hazardous materials routinely handled, as the area in which significant damage to infrastructure could occur (beyond the terminal and the ship) encompasses large sections of one of the largest and busiest ports in the country. The POLB receives very large crude oil carriers (VLCC) at a jetty located within several hundred feet of the eastern boundary of the proposed LNG facility, and a major container terminal which almost certainly receives hazardous cargo lies adjacent to the western side of the proposed site, along which the LNG ship will be berthed. It is noted that the area designated for the terminal's construction, approximately 25 acres, appears to be significantly smaller than the other (existing) terminals in the United States (with the possible exception of the Everett terminal – I do not know at the time of writing what the Everett terminal's area is). In any case, there is very minimal separation between the LNG spill impoundments and the facility's property line in the proposed terminal in the POLB; indeed, it is difficult for me to see how the applicant can meet the exclusion zone requirements of 49 CFR 193, much less provide a reasonable safety zone for the public or surrounding infrastructure.

It must be emphasized that the 3 mile zone is based primarily on the assumption that approximately 3,000,000 gallons of LNG is spilled onto water, as it appears there is little doubt that either pool fire radiation thermal fluxes or flammable vapor clouds from such a spill could put the public in harms way at that distance. However, it is a <u>minimum</u> specification, because it does not address the possibility of even more serious events.

I am very concerned that such events as provide the basis for the 3 mile consequence distance would be of such severity as to make it highly likely, if not almost certain, that further failures of containments, either of LNG or NGL, would occur. In particular, I repeat here my concern that the exposure to the ship of such a pool fire would have the potential to cause cascading failures of the remaining tanks on the vessel, resulting in total loss of the vessel and burning of its contents. There can be no doubt that the consequences of such a worst-possible-case event could be more severe than the rapid release of approximately 3,000,000 gallons of LNG onto water considered in this report.

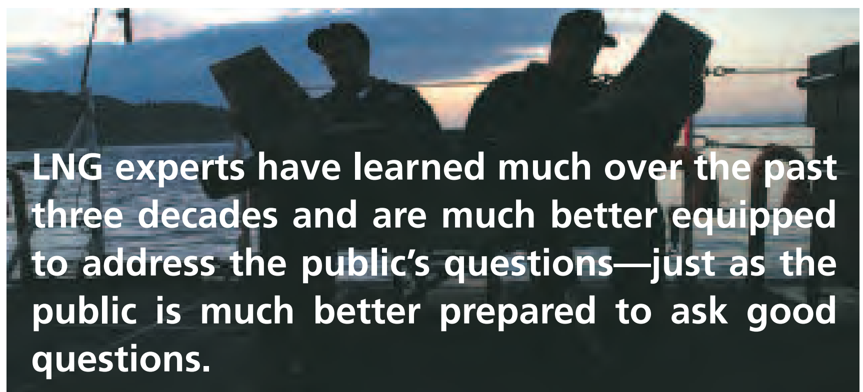
The radius of the circle extending from the terminal location is three miles.

Exhibit 10

LNG and Public Safety Issues

Summarizing current knowledge about potential worst-case consequences of LNG spills onto water.

by Jerry Havens
Professor, Chemical Engineering, University of Arkansas



In 1976 Coast Guard Admirals were being called to Capitol Hill to answer the question: If 25,000 m^3 of liquefied natural gas (LNG) were spilled on water without ignition, how far might a flammable cloud travel before it would not pose a hazard? As technical advisor to the Office of Merchant Marine Safety in the Coast Guard's Bulk Hazardous Cargo Division, I was assigned to provide an answer on the LNG vapor cloud issue within a couple of weeks. Although no longer with the Coast Guard, I am still working on the problem 30 years later.

Past Lessons

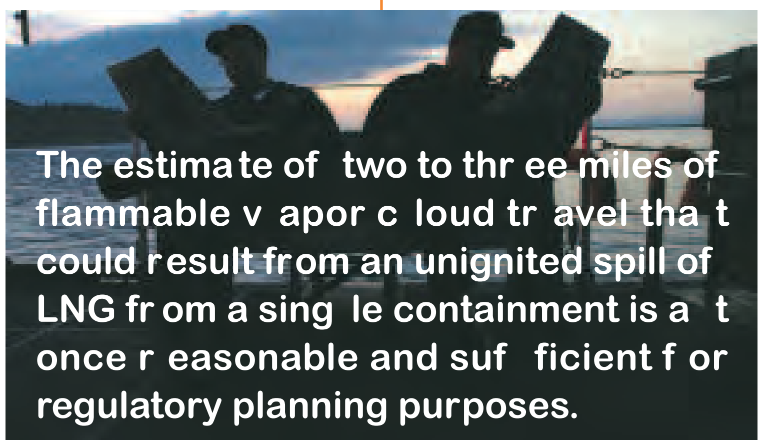
The tragic events of September 11, 2001, changed everything. Watching the World Trade Towers fall sharply focused my research of LNG spills on water. It is understood now that the towers fell because the insulation was knocked off the steel, which could then not withstand the extreme fire exposure. The lesson from this is to understand the consequences of such events, not only in planning for decisions that are within our control, but in planning for events over which we may have little or no control.

LNG experts have learned much over the past three decades and are much better equipped to address the public's questions—just as the public is much better prepared to ask good questions. For space constraints this discussion sidesteps many important issues in the LNG debate; however, it summarizes what is currently known about potential worst-case consequences for public safety of LNG spills onto water.

The description of current LNG knowledge is aided by reference to reports prepared in 2004 by the ABS Shipping Group for the Federal Energy Regulatory Commission[1] and by the Sandia National Laboratory for the Department of Energy.[2] These two reports, which appear to be largely accepted by all of the regulatory agencies involved, emphasize for their analyses one scenario of the consequences of LNG marine spills—spillage onto water of 12,500 m^3 of LNG, which is representative of approximately one half of a single tank on a typical LNG ship. While the Sandia report does provide some consideration of multiple-tank spills, it suggests that such occurrences would not involve more than three tanks at one time. The choice of spillage of only half a tank appears to be the result of the report's consideration of the extreme implausibility of the rapid spillage of the entire tank as an initial result of a terrorist attack. However, limiting discussion to the initial results of a terrorist attack is not necessarily sufficient.

LNG Vapor Cloud Dispersion

My year-long look at the LNG vapor dispersion issue for the Coast Guard produced a report[3] in 1978 that reviewed several predictions by leading authorities of the vapor cloud extent, following spillage of 25,000 m^3 LNG onto water. Those estimates ranged from 0.75 mile to a little over 50 miles. The range was narrowed by showing the errors in reasoning underlying the lowest and highest estimates, but the uncertainty range could not be tightened closer than three to 10 miles.



The estimates, which range between approximately two and three miles, presented in the Sandia and ABS Group reports are endorsable. Note, though, that these estimates are for the spillage of 12,500 m^3 of LNG, half the amount considered in the Coast Guard report produced in 1978. Nonetheless, the estimate of two to three miles of flammable vapor cloud travel that could result from an unignited spill of LNG from a single containment is at once reasonable and sufficient for regulatory planning purposes. Indeed, given the uncertainties involved, the point of diminishing returns has been reached on this scenario for vapor dispersion from a 12,500 m^3 LNG spill on water.

Thermal Radiation from LNG Pool Fires

For thermal radiation from pool fires, the findings of the ABS Group and Sandia reports are also endorsable. Both reports appear to provide estimates of approximately one mile as the distance from a pool fire on a 12,500 m^3 spill on water to which unprotected persons could receive second-degree burns in 30 seconds (based on a thermal flux criterion of 5 KW/m^2). Although this estimate is reasonably representative of the best available estimates of the distance to which the public could be exposed (to this damage criterion), the endorsement is qualified as follows.

First, the use of a thermal flux criterion that would result in second-degree burns in 30 seconds is not necessarily appropriate to ensure public safety, as such exposure essentially ensures that serious burns will occur at that distance to persons who cannot gain shelter within 30 seconds. Aside from questions about the ability of even the most able to gain shelter in such a short time, questions are also raised about the safety of those less able. Lower thermal flux criteria (~1.5 KW/m^2) are prescribed in other national and international regulations designed to provide safe separation distances for the public from fires. Since such lower thermal flux level criteria could increase the distances prescribed in the ABS Group and Sandia reports by as much as one and a half to two times, this end point criteria for ensuring public safety from LNG fires should be reconsidered, especially if the goal is to provide for public safety.

Second, the mathematical modeling methods in the reports that predict the various levels of thermal radiation intensity from a massive LNG pool fire are not on as firm scientific ground as are the methods for predicting vapor cloud dispersion. The vapor cloud question has been more extensively studied to provide data for the models' verification. The physical basis for extrapolation from small-scale experimental data is better understood for vapor dispersion than are the methods in present predictions of thermal radiation extent from pool fires. Sandia and others are considering the need for further large-scale LNG fire testing. Such tests should be conducted with appropriate scientific planning and for the purpose of obtaining experimental data that could be used to verify mathematical modeling methods; this additional testing is advised to provide a better understanding of large LNG fires on water.

However, the Sandia report states that cascading events, resulting either from brittle fracture of structural steel on the ship or failure of the insulation that results in LNG vaporization at rates exceeding the capability of the relief valves, cannot be ruled out. Foamed plastic insulation, widely used on LNG carriers, would be highly susceptible to failure by melting or decomposition. It is a cardinal safety rule that the pressure limits on tanks carrying flammable or reactive materials should not be exceeded, as such excess portends catastrophic rupture of the containment. While the Sandia report concludes that such cascading events would be very unlikely to involve more than three of the five tanks on a typical LNG carrier, the report's optimism in this regard is unexplained. Once cascading failures begin, what would stop the process from resulting in the total loss of all LNG aboard the carrier? More research is required.

Other Hazards

Other hazards associated with spilling LNG onto water include oxygen deprivation, cold-burns, rapid phase transitions, and explosions in confined spaces, as well as the potential for unconfined vapor cloud explosions (UVCEs) if the LNG contains significant heavies. As the hazards of oxygen deprivation and cryogenic burns are not expected to affect the public, they will not be considered further here.

Explosions in confined spaces, either combustion events or events of rapid phase transition, may have the potential for causing secondary damage that could lead to further spillage of LNG. Unconfined vapor cloud explosions cannot be dismissed if the cargo contains significant amounts—perhaps greater than 12 to 18 percent, based on Coast Guard-sponsored tests at China Lake in the 1980s—of gas components heavier than methane. Enrichment in higher boiling point components of LNG remaining on the water can lead to vapor cloud concentrations that pose a UCVE hazard, even if the concentration of liquid initially spilled does not. LNG contact with ship structural steel, rapid phase transitions, and gas explosions in confined spaces on the ship are not expected to pose hazards to the public, except as they may relate to the ship's vulnerability to further damage following the cryogenic cargo spillage onto ship structures, with or without ignition.

Vulnerability Issues

Coast Guard Navigation and Vessel Inspection Circular No. 05-05, "Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic," incorporates requirements for a vulnerability assessment that identifies the exposures that might be exploited to ensure the success of an attempted terrorist attack.[4] Two types of vulnerabilities are considered: system and asset. System vulnerabilities consider the ability of the terrorist to successfully launch an attack; asset vulnerabilities consider the physical properties of the target that may influence the likelihood of success of a terrorist attack.

Worst Case?

The hazards of brittle fracture, rapid phase transitions, and explosions in confined ship spaces, as well as cascading events that may result from the extreme fire exposure a ship would experience if a nominal 12,500 m^3 spill on water around the ship was ignited, will require careful consideration. The definition of the worst case event that could be realized as a result of a terrorist attack is likely to hinge on the assessment of the asset vulnerabilities that is required to be considered in NVIC 05-05. This is largely where our unfinished work remains.

References

1. ABS Consulting, "Consequence Assessment Methods for Incidents Involving Releases from LNG Carriers," FERC contract FERC04C40196, May 2004.

2. Hightower, M., et al., "Guidance on Risk Analysis and Safety Implications of a Large LNG Spill Over Water," Sandia Report SAND2004-6258, December 2004.

3. Havens, J. A., "Predictability of LNG Vapor Dispersion from Catastrophic Spills onto Water," Report CG-M-09-77, Office of Merchant Marine Safety, USCG HQ, 1978.

4. Navigation and Vessel Inspection Circular No. 05-05, "Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic," Commandant, United States Coast Guard, June 2005.

About the author: *Jerry Havens is a chemical engineering professor at the University of Arkansas. He has three decades of experience researching LNG spills onto water.*

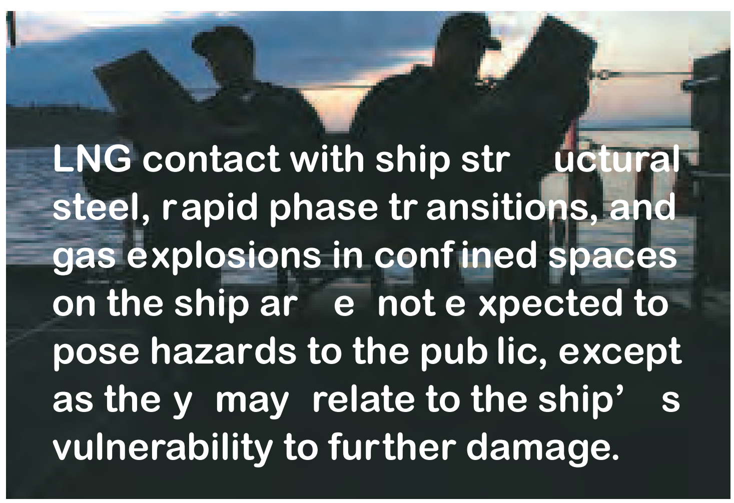


Exhibit 11

https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/

WILLIAMS COMPANIES FAILED TO PROTECT EMPLOYEES IN PLYMOUTH LNG EXPLOSION

The natural gas company eyeing other Northwest projects has a history of unsafe work conditions.

Two employees were inside the compressor building (rear) at the time of the explosion. One sustained severe injuries. by Washington Utilities and Transportation Commission (Used with permission.)

Author: **Tarika Powell**
(@) on June 3, 2016 at 6:30 am

This article is part of the series Fracked Fuel & Petrochemical Projects in the Pacific Northwest

Two years ago, an explosion at a liquefied natural gas (LNG) plant in eastern Washington forced hundreds to evacuate their homes, injured five workers, and caused $69 million in damages. It was one in a string of accidents at The Williams Companies' natural gas facilities that in the last three years has killed five workers and injured at least 120 people.

Through a public records request, Sightline obtained documents from the Washington Department of Labor and Industries (Washington L&I), which conducted an investigation into the safety of employees at the Plymouth plant where the explosion occurred. The agency found that Williams endangered its employees, lacked an adequate emergency response plan, and had deficient safety training. The company's track record—not just in the Northwest, but throughout the US—reveals a pattern of failing to heed safety regulations. It also illustrates why we should not underestimate the fire and explosion hazards of natural gas processing plants such as LNG facilities.

The Williams Plymouth LNG explosion

The explosion happened shortly after 8:00 a.m. on March 31, 2014 at the Plymouth LNG plant in eastern Washington, about 30 miles south of the Tri-Cities, where the company stores natural gas in liquid form in two 14-million-gallon tanks. Natural gas ignited inside the LNG processing equipment, creating a "rolling detonation" that generated a mushroom-shaped cloud and large fire. Members of the public felt the rumble of the explosion up to six miles away, and employees near the explosion were knocked off their feet by its force. Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

The blast completely fragmented a large piece of the natural gas processing equipment called an adsorber, propelling 250 pounds of debris and shrapnel up to 900 feet away and injuring 5 employees. One employee's injuries were so extensive that a coworker who helped him evacuate the grounds did not initially recognize him. The explosion caused extensive physical damage to buildings and electrical equipment and even bent the BNSF rail line near the perimeter of the facility's property.

Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

To make matters worse, on the morning of the explosion, plant operators had shut down two safety monitoring systems. Facility operators disabled both the system that detects gas releases and the emergency shutdown system, which is designed to put facility equipment in "safe mode" should the plant experience hazardous conditions.

Shutting down these systems disabled detectors that would have automatically shut down the plant in an emergency. Instead, employees who were trying to flee the site had to locate and manually pull two separate emergency shutdown switches. Shutting down the systems may have also disabled the plant's alarms, which explains why many employees did not hear alarms after the explosion.

The last remaining employees on site were able to successfully engage the emergency shutdown only after realizing that the system had been disabled. While the shutdown stopped at least one gas leak, other leaks continued for more than 24 hours. Shrapnel from the explosion had pierced multiple gas pipes as well as one of the facility's two 90-foot-tall LNG tanks, resulting in a "roaring noise" as pressurized gas escaped from multiple locations on site. Residents within a two-mile radius were evacuated to the local fairgrounds, but not before the smell of gas had spread at least a quarter-mile from the plant.

Employees evacuated to the nearest fire station, but officials in charge of responding to the incident asked three Williams workers to reenter the premises multiple times while gas continued to leak so they could help plug, patch, or stop the leaks by closing valves at the site. The shutdown valves employees used to stop the leaks were 150 to 450 feet from the original explosion and fire, the area with the highest potential for exposure to hazards. While these employees rather selflessly agreed to assist, it was against the law to put them back into the "hot zone," the portion of a hazard site that is immediately dangerous to life and health, because Williams had not given them adequate emergency training.

Fires burn at site of Plymouth LNG explosion. by Washington Utilities and Transportation Commission (Used with permission.)

A disaster months in the making

Notably, plant operators had set the explosion in motion several months earlier, in November 2013, when they closed off the end of a pipeline with plastic and tape rather than proper sealing equipment, a move that allowed an explosive mixture of air and gas to enter the LNG processing system.

Next, system operators, following the company's written procedures, failed to properly purge excess oxygen from the equipment. The procedure for purging oxygen did not meet industry standards, and investigators with the Washington Utilities and Transportation Commission (UTC) later determined that the instruction manual lacked details that were clear enough for employees to follow with consistent and safe results. The Pipeline and Hazardous Materials Safety Administration's safety violation report notes that the company had been using the inadequate oxygen purge procedure for many years.

Williams' deficient safety training compounded this negligence. Federal workplace safety and health standards require Williams to adequately train employees for emergency response before asking them to participate in a real emergency scenario. To ensure their safety, only employees who have been highly trained in hazardous materials emergency response are permitted to enter a hazard site for the purpose of stopping a gas release. Guidance by the National Fire Protection Association and the International Association of Fire Chiefs supports these laws.

Yet Williams failed to adequately train its workers to enter the area of immediate threat, thereby gravely endangering them. On paper, the company's procedures align with workplace safety regulations, stating that only employees who have received advanced training in hazardous materials and emergency response will be sent into a hot zone or participate in an actual emergency response operation. In fact, the employees who were sent into the hot zone had not received the legally required training, so facility managers had a duty to make sure they remained evacuated from the site.

These workers faced many hazards in the hot zone: in addition to the gas leaking from pipes and the LNG storage tank, the facility houses liquid propane and butane tanks that each hold about 3,000 gallons and that are susceptible to expanding vapor explosions in circumstances such as those that followed the Plymouth explosion. The pipeline leak closest to the original explosion abutted a warehouse that gas had most likely entered, and as a 2010 overview of LNG properties and hazards notes, "explosions occur with noticeable frequency from a buildup of natural gas vapors indoors."

In addition to failing to adequately train its employees, Williams did not provide them with the protective clothing and equipment necessary to enter an area containing fire and explosion hazards. Workplace safety laws require that employers provide appropriate protective equipment to any personnel who enter a hazardous site, including a respirator and protective clothing that would cover all parts of the body that could be harmed by the hazard. While firefighters wore full protective gear and respirators, Williams provided only one of the employees with comparable protective equipment to enter the hot zone. Another was only given a flame-resistant shirt and pants, while the third employee was only provided with a flame-resistant shirt.

Washington L&I found that Williams placed its employees in close proximity to gas leaks that were likely to cause injury from a fire or explosion. The state determined that Williams' emergency response plan was not effective in practice because the company only provided limited emergency response training. Further, the agency noted deficiencies in Williams' written health and safety programs. Washington L&I fined Williams $1,000 (later adjusted down to $300) and ordered the company to correct the violations by giving the employees appropriate emergency response and hazardous materials training.

Rocky inspection record at Plymouth LNG

Past inspections at the eastern Washington facility foreshadowed Williams' lack of preparation for fire hazards or natural gas releases. A 2002 inspection by the UTC found fully ten areas of concern at the facility. Some of the fire detectors were too weak to detect hazards more than a couple feet from the equipment, and another was out of alignment with the area it was supposed to monitor. The company's procedures did not require that gas detection systems meet the National Fire Protection Association's minimum LNG fire protection requirements, and plant operators were not able to provide documentation that staff regularly checked the equipment for leaks. Further, the company lacked procedures to minimize the recurrence of safety incidents.

A V-shaped ice formation develops above the puncture on Plymouth LNG tank while pipe (lower left) spews LNG and gas vapor. By Washington Utilities and Transportation Commission (Used with permission.)

In other failings, a 2007 inspection by the UTC noted that for at least two years, Williams technicians had not correctly read the output for one of the cathodic protection devices, which help prevent leaks by monitoring corrosion in metal structures such as liquid gas storage tanks and pipes. They hadn't done so because the technicians themselves were confused about the configuration of the equipment.

In 2008, the UTC issued a violation to facility operators because they did not inspect and test fire control systems within six-month intervals, as required by federal LNG standards. Two of Williams' senior officials at the plant were "surprised that there was no grace period in the code" that allowed them to exceed the six-month minimum requirement for testing fire equipment.

Company's workplace safety problems have triggered federal probes

The Williams Companies is a natural gas corporation with hundreds of miles of pipeline in the western states and along the Atlantic coast. The company was set to build 232 miles of pipeline through Oregon for the Jordan Cove LNG export project, which federal regulators rejected in March 2016, and 85 miles of pipeline for the proposed Oregon LNG export facility, which developers withdrew from consideration in April 2016.

Both federal and state agencies have fined the company on numerous occasions for poor operations of natural gas plants and pipelines, but in the past three years, an alarming number of explosions and fires have broken out at The Williams Companies' natural gas and petrochemicals facilities, suggesting a pattern of recklessness that reaches far beyond Plymouth.

For example, a flash fire at one of the company's natural gas compression facilities injured fifteen people in New Jersey in May 2013. That same month, a Pennsylvania gas compressor station caught fire with eleven employees on site. In June 2013, an explosion at a Louisiana olefins plant killed two workers and injured more than 100 others. Then in October 2013, another explosion killed three contractors at a different Louisiana facility. A month after the March 2014 explosion at Plymouth LNG, an explosion at a Williams gas gathering facility in a small Wyoming town forced residents to evacuate.

The Occupational Safety and Health Administration found that the company failed in its responsibility to find and fix safety violations and ensure the safety of workers at its Louisiana olefins plant. The string of accidents also triggered the US Chemical Safety

Board to initiate a federal probe into Williams' safety practices. That investigation has been slow-going.

Williams resumes business as usual in Washington

Williams failed to properly train and equip its employees for emergency response, and it did not adequately coordinate with local first responders so that they could address the hazard without endangering employees. The company's failure increased the dangers of the hazard not only for employees and first responders, but also for the broader community.

There is reason to worry The Williams Companies will continue to shirk safety standards.

After paying a very small fine for its actions, Williams has moved forward. The company has now completed all the repairs necessary to resume full operations at Plymouth, and it is slated to build the pipeline for a proposed methanol facility at the Port of Kalama, Washington. But the company's record, along with ongoing investigations into the company's practices by Washington L&I and the UTC, demonstrate there is reason to worry The Williams Companies will continue to shirk safety standards—potentially endangering Williams' employees and nearby communities once again.
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Exhibit 12

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May 21, 2010

LAND USE HEARING (FILE # HBCU-10-01

SUPPLEMENTAL TESTIMONY

I have previously submitted written and oral testimony in this case.

During the Applicant's Rebuttal phase at the hearing on May 20, a matter came up that I feel warrants further discussion.

A participant at the hearing had offered oral testimony regarding his concern that installing the pipeline across the floor of the bay might re-activate pollutants buried in the bottom sediments.

His concerns have merit.

Research has shown that Coos Bay contains a number of introduced contaminants, including several chlorinated hydrocarbons. Chlorinated hydrocarbons are extremely worrisome in that, once introduced into an ecosystem, they are not broken down by natural processes and persist in their original form almost indefinitely. While they are not metabolized and inactivated, they can be removed from cycling through the food chain by, for example, becoming sequestered and buried in bottom sediments. Significant disturbances of bottom sediments, such as by trenching and burying a new pipeline, release these contaminants to once again re-enter the food cycle where they essentially have the effect of increasing the dosage to which living elements are exposed.

For a more comprehensive and documented discussion of these points, please see my previous testimony in the Jordan Cove Marine Docking Berth land use hearing included herewith as Enclosure #1.

Reacting to these concerns during the Rebuttal phase, the Applicant's stated they would be sampling the sediments along the pipeline route across the bay. They stated that an unspecified standardized evaluation process would be used which apparently refers to the protocol used by the Corps of Engineers.

That is all well and good, but one thing is highly probable. The results of the testing will almost certainly show some level of contaminants occurring at sub-lethal doses.

It is at this point that the logic of attempting to complete the land use approval process in the absence of a viable Environmental Impact Statement begins to disintegrate.

Let's assume, for the sake of argument, the sediments show a few parts per billion (ppb) each of polychlorinated biphenyls (PCBs) and polycyclic aromatic hydrocarbons (PAHs). Apparently nothing to worry about, these are small amounts and any released contaminants would be washed away with the next outgoing tide. Based on the record currently before the Board of Commissioners, the decision would no doubt be to go ahead and approve the pipeline installation as this small amount of persistent organic pollutants recycling through the food chain should not cause any apparent bad effects.

If a viable EIS were available, in the section entitled "Affected Environment" (missing entirely, by the way, from the Jordan Cove FEIS), we would find that juvenile Chinook salmon currently swimming in the Coos Bay estuary carry 25 ppb of PCBs and 300 ppb of PAHs in their bodies. We would learn that juvenile salmon and their prey bioaccumulate chlorinated hydrocarbons whenever they become available in the food chain with detrimental effects on their immune systems which results in increased disease susceptibility (Enclosure 1). In addition, at some level, genetic effects begin to appear. In addition, rather than being flushed away on the next tide, we would learn that particles suspended in the water column in parts of Coos Bay can take as long as 48 days to be flushed from the estuary (Enclosure 1).

At this point, from a land use approval perspective, it would be apparent that a rubber stamp approval of the project would not be warranted, as the possibility exists the planned project could move us closer to a threshold which could initiate irreversible catastrophic impacts on the bay ecosystem. However, the unknown probability of this happening would cause a reluctance to cancel the project out of hand.

At this point, it would be logical to refer back to the EIS once again and turn to the sections on "Need for the project" (also missing from the Jordan Cove EIS) as well as the section which gives a balanced and complete side-by side comparison of the proposed project and all reasonable alternatives (yet again, missing from the Jordan Cove EIS).

The rationale of a logical land use decision could be developed as follows:

- If the need was dire and immediate, and if few viable alternatives were available, it would not be arbitrary or capricious to knowingly accept the environmental risks to the estuary and approve the pipeline in order to better serve the greater societal needs.

- If the need was speculative and future oriented, and if there were viable alternatives in place or readily available, it would not be worthwhile to risk the real possibility but uncertain probability of triggering catastrophic impacts to the estuarine ecosystem and the pipeline would not be approved.

In my estimation, the interplay of a valid and complete EIS within the County land use approval process is absolutely essential in this case given the importance and possible long-term implications of the decision to be made.

I understand the legal constraints placed on the Hearing Officer by the existing County land use approval process. I also understand this to be a somewhat arcane process probably inadequate to function adequately in today's managerial climate.

I find that the Oregon Progress Board essentially agrees with this premise: "The State's existing environmental data collection and management system must be improved to effectively measure ecological conditions, trends or risks. Measuring ecological conditions, trends, and risks is fundamentally different from the problems Oregon's environmental programs were initially established to address. Resolving them will require new approaches....." (Oregon State of the Environment Report 2000, Statewide Summary, page 3).

I ask that you apply your best creative efforts to find a way to postpone the land use approval decision until such time as it can be more fully and logically considered within the context of a viable and objective Environmental Impact Statement. I believe the environmental risks involved fully justify your efforts in this area.

Ron Sadler

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In the matter of: Coos County Land Use Hearing
Jordan Cove Marine Docking Berth

September 17, 2007
Coquille, Oregon

Testimony of Ron Sadler:

It is critical to remember, as was stated in a U.S. Department of Interior report, that Coos Bay is truly an ecosystem and one modification or activity could start a chain reaction which could affect the whole, resulting in severe damage to certain natural resources.[1]

The displacement, handling, and disposition of approximately 6,000,000 cubic yards of excavated and dredged material from the bottom and shoreline of the bay is certainly an activity that has great potential to do significant damage to marine life in the estuary, especially salmonid fish populations. This potential for damage is especially worrisome given what the sediments involved may contain.

Samples taken at various points in the Coos Bay estuary have shown concentrations of toxic materials in bottom sediments exceeding levels at which ecological effects are noted. These toxins include Tributyltin, arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs).[2]

In addition, there are ongoing inputs of materials that may contribute to the accumulation of toxins in bottom sediments. In the year 2000, for example, there were inputs totaling 2,470 pounds of arsenic, chromium, zinc, copper, and mercury released in Coos County.[3] Further, the Coos Bay estuary receives unknown amounts of aliphatic organochlorines, chlorinated dibenzofurans, chlorinated phenols, and metabolites of each, as a by-product of the release of treated municipal wastewater. Looking further back in time, 40 years ago there was a pulp mill located on the bay at Empire. Its outfall of wastewater entered the bay untreated via a pipe located in the middle of the shipping channel. The resulting outflow resulted in a linear "dead zone" extending towards the mouth of Coos Bay. The types and amounts of toxins residing in the deep sediments at this location have not been investigated to my knowledge.

The various chlorinated organic compounds mentioned above are known as POPs – persistent organic pollutants. At the molecular level, they are extremely stable and

ENCLOSURE # 1

virtually indestructible by natural processes. In some instances, polymer chains may be broken by natural processes, but may recombine to form new compounds (metabolites) even more toxic than the originals.

Most appropriate to this discussion, then, is the fact that toxic material such as metals, PCBs, PAHs, etc. once released into the environment can remain unchanged for thousands of years. They are not biodegraded into more benign substances. They continue to cycle through the ecosystem raising havoc until they become no longer available to the flora and fauna through the process of sequestration.

In an estuarine ecosystem, the primary mechanism for sequestering toxins results in them being locked up by becoming buried in or attached to bottom sediments. There they remain out of reach of most organisms until some disturbance releases them to re-enter the food chain once again.

This is not a perfect process, however, as evidenced by conditions as they exist in Coos Bay today. Juvenile Chinook salmon in the Coos Bay estuary presently carry about 300 ppb of PAH metabolite concentrations in their bodies. They also carry about 25 ppb of PCB concentrations. As testimony to the longevity of these types of toxins, they also carry about 9 ppb of DDT concentrations, a full 30 years after its use was banned.[4]

It is well established that sediments in estuaries sequester and act as repositories for contaminants. It has also been shown that juvenile salmon and their prey bioaccumulate chlorinated and aromatic hydrocarbons, when they become available in the food chain, with detrimental effects on their immune systems which results in increased disease susceptibility.[5] Given current baseline loadings of toxins in juvenile salmon, how much room exists for additional inputs of toxins before critical thresholds are crossed?

The dynamics of tidal flows in estuaries are often viewed in simplistic terms. It is tempting to think of a cloud of murky water, with its associated toxins, created by dredging being carried out of sight and out of mind by the next out-going tide. This is not realistic, however. Studies have shown that a particle suspended in the water column in parts of Coos Bay can take as long as 48 days to be flushed from the estuary.[6]

Given the serious and potentially catastrophic effects that could negatively impact the salmonid productivity of the Coos Bay estuary, it appears premature and inappropriate to approve the construction of the marine docking berth at this time.

Several key elements of information essential to an informed and rational decision appear to be missing at this time. A viable decision process would require the following:

1. An intensive sampling of all areas proposed for dredging or excavation, to the full depth of planned disturbance, to determine the types and concentrations of all toxins expected in the spoils.

2. A detailed and explicit disposal and/or storage plan for all dredged and excavated material, with explicit requirements to prevent water or wind borne re-deposition in the estuary.

3. A risk assessment detailing an estimation of the net effects of unavoidable releases of sequestered toxins on salmonid productivity.

I ask that this information be gathered and analyzed before further action is taken on the marine docking berth proposal.

FOOTNOTES

1. USDI, "Natural Resources, Ecological Aspects, Uses and Guidelines for the Management of Coos Bay", L. B. Day, June, 1971, pg. 128.
2. NOAA, "Preliminary Natural Resource Survey, Coos Bay, December 12, 1997, pg. 11.
3. EPA, "Toxic Release Inventory, Coos County, Oregon", 2000
4. Dr. Mary Arkoosh, National Marine Fisheries Service, Newport, Oregon, 2000.
5. Dr. Mary Arkoosh, "Effect of Pollution on Fish Diseases: Potential Impacts on Salmonid Populations", Journal of Aquatic Animal Health, Vol. 10, June 1998, pp. 182-190.
6. Arneson, "Seasonal Variation in Tidal Dynamics, Water Quality and Sediments in the Coos Bay Estuary", OSU Masters Thesis, June, 1976.

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Exhibit 13

WILDLIFE DIVISION
Regulating harvest, health, and enhancement of wildlife populations

Threatened, Endangered, and Candidate Fish and Wildlife Species

(T= Threatened, E= Endangered, C= Candidate, DPS= Distinct Population Segment)

Threatened, Endangered, and Candidate Fish and Wildlife Species in Oregon (pdf)

Common Name	Scientific Name	State Status*	Federal Status
FISH			
Borax Lake Chub	*Siphateles boraxobius*	T	E
Bull Trout (range-wide)	*Salvelinus confluentus*		T
Columbia River Chum Salmon	*Oncorhynchus keta*		T
Foskett Spring Speckled Dace	*Rhinichthys osculus* ssp		T
Green Sturgeon (Southern DPS)	*Acipenser medirostris*		T
Hutton Spring Tui Chub	*Siphateles bicolor* ssp	T	T
Lahontan Cutthroat Trout	*Oncorhynchus clarki henshawi*	T	T
Lost River Sucker	*Deltistes luxatus*	E	E
Lower Columbia River Chinook Salmon	*Oncorhynchus tshawytscha*		T
Lower Columbia River Coho Salmon	*Oncorhynchus kisutch*	E	T
Lower Columbia River Steelhead	*Oncorhynchus mykiss*		T
Middle Columbia River Steelhead	*Oncorhynchus mykiss*		T
Oregon Coast Coho Salmon	*Oncorhynchus kisutch*		T
Pacific Eulachon/Smelt (Southern DPS)	*Thaleichthys pacificus*		T
Shortnose Sucker	*Chasmistes brevirostris*	E	E
Snake River Chinook Salmon (Fall)	*Oncorhynchus tshawytscha*	T	T
Snake River Chinook Salmon (Spring/Summer)	*Oncorhynchus tshawytscha*	T	T
Snake River Sockeye Salmon	*Oncorhynchus nerka*		E
Snake River Steelhead	*Oncorhynchus mykiss*		T
Southern Oregon/Northern California Coast Coho Salmon	*Oncorhynchus kisutch*		T
Upper Columbia River Spring Chinook Salmon	*Oncorhynchus tshawytscha*		E
Upper Columbia River Steelhead	*Oncorhynchus mykiss*		T
Upper Willamette River Chinook Salmon	*Oncorhynchus tshawytscha*		T
Upper Willamette River Steelhead	*Oncorhynchus mykiss*		T

Warner Sucker	*Catostomus warnerensis*	T	T
AMPHIBIANS AND REPTILES			
Green Sea Turtle	*Chelonia mydas*	E	T
Leatherback Sea Turtle	*Dermochelys coriacea*	E	E
Loggerhead Sea Turtle	*Caretta caretta*	T	E
Olive Ridley Sea Turtle	*Lepidochelys olivacea*	T	T
Oregon Spotted Frog	*Rana pretiosa*		T
BIRDS			
California Brown Pelican	*Pelecanus occidentalis californicus*	E	
California Least Tern	*Sternula antillarum browni*	E	E
Marbled Murrelet	*Brachyramphus marmoratus*	T	T
Northern Spotted Owl	*Strix occidentalis caurina*	T	T
Short-tailed Albatross	*Phoebastria albatrus*	E	E
Streaked Horned Lark	*Eremophila alpestris strigata*		T
Western Snowy Plover	*Charadrius nivosus nivosus*	T	T (Pacific Coast population DPS)
Yellow-billed Cuckoo (Western DPS)	*Coccyzus americanus*		T
MAMMALS			
Blue Whale	*Balaenoptera musculus*	E	E
Canada Lynx	*Lynx canadensis*		T
Columbian White-tailed Deer (Columbia River DPS)	*Odocoileus virginianus leucurus*		T
Fin Whale	*Balaenoptera physalus*	E	E
Gray Whale	*Eschrichtius robustus*	E	
Gray Wolf	*Canis lupus*		E1
Humpback Whale	*Megaptera novaeangliae*	E	E
Killer Whale (Southern Resident DPS)	*Orcinus orca*		E
Kit Fox	*Vulpes macrotis*	T	
North Pacific Right Whale	*Eubalaena japonica*	E	E
Red Tree Vole (North Oregon Coast DPS)	*Arborimus longicaudus*		C
Sea Otter	*Enhydra lutris*	T	T
Sei Whale	*Balaenoptera borealis*	E	E
Sperm Whale	*Physeter macrocephalus*	E	E
Washington Ground Squirrel	*Urocitellus washingtoni*	E	
Wolverine	*Gulo gulo*	T	

* Listed under the Oregon Endangered Species Act (ORS 496.171 through 496.192)

1: The gray wolf is protected as endangered under the authority of the federal Endangered Species Act in Oregon west of highways 395, 78, and 95.

Revised June 11, 2018

4034 Fairview Industrial Drive SE :: Salem, OR 97302 :: Main Phone (503) 947-6000 or (800) 720-ODFW [6339]

Do you have a question or comment for ODFW? Contact ODFW's Public Service Representative at: odfw.info@state.or.us
Share your opinion or comments on a Fish and Wildlife Commission issue at: odfw.commission@state.or.us

Oregon Coast Coho

ESA Listing Status: *Threatened* on June 20, 2011 *250kb*; updated April 14, 2014 *503kb*

ESU Definition: This evolutionarily significant unit, or ESU, includes naturally spawned coho salmon originating from coastal rivers south of the Columbia River and north of Cape Blanco, and also coho salmon from one artificial propagation program: Cow Creek Hatchery Program (Oregon Department of Fish and Wildlife Stock #18).

Current Population Trends:

- Salmon Population Trend Summaries
- Salmon Population Summary Database
- 5-Year Salmon Status Review *1.2MB*

Critical Habitat: Designated Feb. 11, 2008 *1.5MB*

- Supporting Information

Protective Regulations: Issued Feb. 11, 2008 *1.5MB*

Coho Salmon Status Reviews

Coho Salmon Federal Register Notices

Coho Salmon Maps & GIS Data

ESA Chronology for Oregon Coast Coho

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West Coast Region Home » Green Sturgeon

Green Sturgeon

Twenty seven species of sturgeons can be found in temperate waters of the Northern Hemisphere, two of which reside on the West Coast of North America: the green sturgeon (*Acipenser medirostris)* and the white sturgeon *(Acipenser transmontanus)*.

NOAA Fisheries received a petition in June 2001 from several environmental organizations requesting that the agency list the North American green sturgeon under the Endangered Species Act (ESA). On April 7, 2006, NOAA Fisheries listed the southern distinct population segment, or sDPS, of North American green sturgeon as threatened under the ESA. Critical habitat was designated on October 9, 2009. On June 2, 2010, NOAA Fisheries published final ESA protective regulations 4(d) for the southern distinct population segment of North American green sturgeon, and released a final environmental assessment analyzing the environmental impacts of these ESA Section 4(d) rules. The northern distinct population segment, or nDPS, of North American green sturgeon is a species of concern within the region.

Species Background

Biology

Life History

Threats

Critical Habitat

Status Reviews

Education

Identification Guide

Conservation Efforts & Research

Management & Policy

Final Recovery Plan, August 2018

- Final sDPS Green Sturgeon Recovery Plan
- Appendix A - Final sDPS Green Sturgeon Recovery Plan

Draft Recovery Plan, January 2018

- *Federal Register* notice requesting comments on Draft sDPS Green Stugeon Recovery Plan

ESA Listing

- *Federal Register* Notice, April 7, 2006, Southern DPS
  - updated April 14, 2014
- References for Final Rule Listing, Southern DPS
- Final Green Sturgeon Listing Q & A

Protective Regulations, ESA Section 4(d)

- News Release
- *Federal Register* Notice
- Environmental Assessment
- Impact Review
- Flexibility Analysis
- References for 4(d) rule

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NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION

Eulachon

Eulachon are an anadromous forage fish and are endemic to the northeastern Pacific Ocean; they range from northern California to southwest and south-central Alaska and into the southeastern Bering Sea. The southern DPS of eulachon is comprised of fish that spawn in rivers south of the Nass River in British Columbia to, and including, the Mad River in California. Adult eulachon typically spawn at age 2-5 in the lower portions of rivers. Many rivers within the range of eulachon have consistent yearly spawning runs; however, eulachon may appear in other rivers only on an irregular or occasional basis. The spawning migration usually occurs between December and June.

If you have any questions about the recovery planning process or for more information, please contact Robert Anderson, 503-231-2226.

Recovery Planning

FINAL Recovery Plan for the Southern DPS of Eulachon September 2017

Notice of Intent to Prepare a Recovery Plan for the Southern DPS of Eulachon 78 *FR* 40104, July 3, 2013

DRAFT Eulachon Recovery Plan October 20, 2016

FR Notice October 20, 2016

Recovery Plan Outline

Listing Information

Eulachon Species Information

ESA Listing Status *Threatened* 75 FR 13012, March 18, 2010

Endangered and Threatened Wildlife; Final Rule to Revise the Code of Federal Regulations for Species under the Jurisdiction of the National Marine Fisheries Service April 14, 2014

Eulachon Critical Habitat 76 FR 65324, Oct 20, 2011

2016 5-Year Review Summary and Evaluation

2016 Status Review Update

Initiation of Eulachon 5-Year Status Review

2010 Eulachon Status Review

2008 Eulachon Status Review

Resources

Washington Department of Fish and Wildlife

http://wdfw.wa.gov/

http://wdfw.wa.gov/conservation/fisheries/smelt/

Oregon Department of Fish and Wildlife

www.dfw.state.or.us/

www.dfw.state.or.us/fish/oscrp/cri/publications.asp#Eulachon

California Department of Fish and Wildlife

www.wildlife.ca.gov/

file:///C:/Users/robert/Downloads/06_Anadromous%20Fish_092415[1].p

Department of Fisheries and Oceans, Canada

www.dfo-mpo.gc.ca/index-eng.htm

www.pac.dfo-mpo.gc.ca/science/species-especes/pelagic-pelagique/eulachon-eulakane-eng.html

Studies of Eulachon Smelt in OR and WA, 2014

Eulachon Newsletters

September 2014 Eulachon Newsletter

December 2014 Eulachon Newsletter

July 2015 Eulachon Newsletter

December 2015 Eulachon Newsletter

Biological Opinions

ESA-Listed Marine Mammals

NOAA Fisheries has listed 22 species of marine mammals under the Endangered Species Act, where 8 of those species are from the West Coast. We manage 7 different species of cetaceans (listed below) and Guadalupe fur seals. NOAA Fisheries' **Alaska Region** manages Steller sea lions. The Alaska Fisheries Science Center's **Marine Mammal Laboratory does research on Steller sea lions**.

Blue Whales

Fin Whales

Guadalupe Fur Seals

Central America **Humpback Whale** DPS * change in status, endangered as of October 2016

Mexico **Humpback Whale** DPS * change in status, threatened as of October 2016

Northern Pacific Right Whales

Western North Pacific Gray Whales

Sei Whales

Southern Resident Killer Whales

Sperm Whales

Steller Sea Lions * change in status, *delisted* as of December 2013

Sea Turtles

We share jurisdiction of marine turtles with the U.S. Fish & Wildlife Service. Sightings and strandings of turtles listed under the Endangered Species Act (ESA) in the region are rare, and there are no breeding beaches in California, Oregon, or Washington. However, encounters may occur. **Please report a dead, injured, or stranded sea turtle by calling: 1-866-767-6114.** Additional species information is provided below.

ESA-Listed Sea Turtles

Critical Habitat Designation for Pacific Leatherback Sea Turtles

- News release
- Federal Register Notice

Species in the Spotlight Initiative - Pacific Leatherback Sea Turtles

- Five-Year Action Plan

Point Reyes bird's-beak (*Cordylanthus maritimus* ssp. *palustris*)

ENDANGERED

Flowers (left), habit (center), and habitat (right) of Point Reyes bird's-beak. Photos by Melissa Carr. If downloading images from this website, please credit the photographer.

Family
Orobanchaceae

Taxonomic notes
Synonym: *Chloropyron maritimum* ssp. *palustre**

*Revised classification by Tank et al. (2009) based on recent molecular research of subtribe Castillejinae (Orobanchaceae).

This taxon was formerly included within the Scrophulariaceae.

Plant description
Point Reyes bird's-beak is a halophytic annual 10-20 (-30) cm tall, simple or sparingly branched with ascending lateral branches equal to or shorter than the central spike. The herbage is grayish green to glaucous, often purplish tinged, and villous to glabrescent. Leaves are oblong to oblong-lanceolate, 1-2.5 cm long and 0.3-0.7 cm wide, with a blunt to pointed apex. Flowers are arranged in dense spikes with oblong floral bracts bearing a pair of short teeth near the apex. The corolla is 1.8-2.5 cm long, the lower lip and pouch suffused with pinkish to purplish red, the galea pale cream to white. Capsules produce 10-20 seeds that are 0.2-0.3 cm long.

Distinguishing characteristics
Point Reyes bird's-beak shares the same coastal salt marsh habitat as *Cordylanthus maritimus* ssp. *maritimus* (*Chloropyron maritimum* ssp. *maritimum*), but the two taxa are geographically separated by over 100 air miles (160 km), with the latter species restricted to southern California. Point Reyes bird's beak is distinguished from *C. m.* ssp. *maritimus* by its simple or few-branched stem with branches equal to or shorter than the central spike, by its larger, broader leaves, denser and somewhat broader spikes, and larger bracts and flowers. Another subspecies, ssp. *canescens*, is a widespread species of the Great Basin associated with alkaline lakes and hot springs.

When to survey
Surveys for Point Reyes bird's-beak should be conducted when the species is flowering, from June to October.

Habitat
Point Reye's bird's-beak inhabits the upper end of maritime salt marshes at approximately 2.3-2.6 m (7.5-8.5 ft) above Mean Lower Low Water (MLLW, the mean height of water at the lowest of the daily low tides), in sandy substrates with soil salinity 34-55 ppt, and less than 30% bare soil in summer.

Point Reyes bird's-beak is a hemiparasite, forming root connections with host plants from which it derives some of its resources. Point Reyes bird's-beak is not host-specific, but standard hosts for the species probably include *Salicornia virginica*, *Jaumea carnosa*, *Distichlis spicata*, *Limonium californicum,* and *Deschampsia cespitosa*. Other associated species are *Cuscuta salina, Plantago maritima*, *Hordeum jubatum*, *Juncus gerardii*, *Castilleja ambigua* var. *ambigua*, *Spergularia macrotheca*, *S. canadensis*, *Atriplex patula*, *Carex lyngbyei*, *and Glaux maritima.*

Range
Point Reyes bird's-beak occurs along the Pacific Coast from Tillamook County in Oregon, south to Santa Clara County, California. In Oregon, the species is restricted to Netarts Bay, Yaquina Bay, and Coos Bay, with the majority of known occurrences located in Coos Bay.

Oregon counties
Coos, Lincoln, Tillamook

Federal status
Species of Concern

Threats
The primary threat to Point Reyes bird's-beak is habitat loss due to development. The species is also threatened by off-road vehicle use, water pollution, and habitat alteration due to invasion by non-native *Spartina densiflora*.

Did you know?
Research indicates that Point Reyes bird's-beak and other hemiparasites help reduce the abundance of competitive dominant plants, promote plant species diversity, and reduce root zone salinity stress in salt marsh communities.

References
Chuang, T. I. and L. R. Heckard. 1973. Taxonomy of *Cordylanthus* subgenus Hemistegia (Scrophulariaceae). Brittonia 25:135-158.

Clifford, P. M. 2002. Dense-flowered cordgrass (*Spartina densiflora*) in Humboldt Bay, summary and literature review. California State Coastal Conservancy, Oakland, California.

Grewell, B. J. 2008. Hemiparasites generate environmental heterogeneity and enhance species coexistence in salt marshes. Ecological Applications 18:1297-1306.

Kaye, T. 1992. Population monitoring for salt marsh bird's beak, *Cordylanthus maritimus* ssp. *palustris*, Second year summary. Unpublished report for the Bureau of

Land Management, Coos Bay District, Coos Bay, Oregon. Oregon Department of Agriculture, Salem, Oregon. 33 pp.

Meinke, R.J. 1982. Threatened and endangered vascular plants of Oregon: An illustrated guide. Unpublished report for the U.S. Fish and Wildlife Service, Region 1, Portland, Oregon. Oregon Department of Agriculture, Salem, Oregon.

ORNHIC (Oregon Natural Heritage Information Center). 2007. Rare, threatened and endangered species of Oregon. Oregon Natural Heritage Information Center, Oregon State University, Portland, Oregon.

ORNHIC (Oregon Natural Heritage Information Center). 2010. ORNHIC element occurrence database. Portland, Oregon.

Rittenhouse, B. 1999. Status of salt marsh bird's-beak (*Cordylanthus maritimus* ssp. *palustris*) in the Coos Bay Estuary. Bureau of Land Management, Coos Bay District, Coos Bay, Oregon. 10+ pp.

Tank, D.C., J. M. Egger, and R. G. Olmstead. 2009. Phylogenetic classification of subtribe Castillejinae (Orobanchaceae). Systematic Botany 34:182-197.

Exhibit 14

Shell's Sakhalin II LNG project:
Impacts of LNG production

2002 project design included a LNG jetty of 1,400 m length, and around 160,000 m3 of dredging
2003 project design (finally implemented) involved a LNG jetty that was 800 m in length, requiring around 1,680,000 m3 of dredging. Final amount of dredging was about 2 million m3.
(2 million cubic meters is equal to 2.6 million cubic yards)

What Avina Bay looked like BEFORE dredging work and dumping of dredged materials…..

Cont:

What Avina Bay looked like BEFORE dredging work and dumping of dredged materials…..

Aniva Bay - the same area AFTER….

The 2 pictures below were done in Aniva Bay, a year after dumping on the area, which, according SEIC, should not have any negative impact (sedimentation) from the dumping zone.
Now this area is almost an underwater desert.

“Shell's Sakhalin II LNG project in Russia”

Photo to Left Above: *Shell's Sakhalin II LNG project in Russia. Upstream of wild salmon spawning river huge sedimentation contamination occurred. Salmon can swim up rivers with high content of suspended solids, but cannot spawn in water with suspended solids content 220 mg a liter and higher.*
Photo to Right Above: *Ozernaya river on Sakhalin Island several km downstream of pipeline crossings: Females died before laying eggs*
Photos below: *Landslides and erosion from Shell's Sakhalin II LNG pipeline project in Russia.*

Many of our local industries depend on environmentally sound, ecological and biological systems working properly in our Coastal Zone and those systems not being compromised. We know what the environmental impact results ended up being with regard to Russia’s Sakhalin Island. Fishing there is still suffering with low fish returns in areas where gas and oil developments have taken place. Can we expect these same kinds of impacts to occur in Oregon? Who will monitor the Pacific Connector Gas Pipeline so that what is being promised currently by them in regard to the construction of the Pacific Connector is actually completed as promised and without this same degradation? If proposed mitigation measures fail, what will be the recourse? We already have compromised streams and low fish runs in the South Coast Basin. Will Pacific Connector impacts push already compromised biological and ecological systems over the edge?

http://money.cnn.com/magazines/fortune/fortune_archive/2007/02/05/8399125/index.htm

FORTUNE

Shell shakedown

Fortune's Abrahm Lustgarten reports how the world's second-largest oil company lost control of its $22 billion project on Russia's Sakhalin Island.

By Abrahm Lustgarten, Fortune
February 1 2007: 12:10 PM EST

(Fortune Magazine) -- Word that control of the world's largest integrated oil and gas project had been wrested from Royal Dutch Shell trickled down to the company's staff on Russia's Sakhalin Island in December the same way it reached everyone else: via the newswires.

Outside Shell's six-story steel-and-glass compound in Yuzhno-Sakhalinsk, a town of 175,000, snow swirled in subzero wind past drab rows of communist-era cinderblock apartments. Inside, Jim Niven, the company's gregarious head of external affairs, was halfway through an upbeat presentation on the vast potential held in this claw-shaped island dangling from the Siberian Arctic - an estimated 45 billion barrels of oil and gas - when he was interrupted by a nervous colleague, paper in hand.

The news was stunning, even if rumors had been flying: Shell (Charts) was halving its ownership in the $22 billion project, cutting its stake from 55% to 27.5%, and Gazprom, the Russian gas giant, was stepping in, buying Shell's share plus half the stakes owned by Japanese partners Mitsui and Mitsubishi, for just $7.5 billion - the equivalent, says a Shell spokesman, of "paying to enter on the ground floor, as if they were a shareholder at the beginning." The foreign companies also agreed to absorb $3.6 billion of the project's mounting cost overruns.

Shell's top executives, who were in Moscow at the time, weren't negotiating from a position of strength. Not in Vladimir Putin's Russia, where strong-arm tactics have been used to reassert government control of the country's vast natural resources. Last summer the Russian Ministry of Natural Resources suddenly backed Sakhalin Island environmentalists, revoking permits and delaying work on twin 400-mile pipelines that connect to a monstrous LNG terminal and an oil-export facility. The threat of a $50 billion lawsuit meant Shell stood to lose everything.

"A guy says, 'Give me half of what is in your pocket, or I shoot you and kill you,'" says Oppenheimer oil analyst Fadel Gheit. "You give him half and say, 'Thank God I am alive to live another day.' They could have lost all of it."

That December night Yuzhno was abuzz with the news. In the Chameleon bar, where Russian bands hammer out Western rock riffs and twentysomethings pass the hose of a hookah pipe, phones started to vibrate and text messages were thumbed out. The talk was exultant, nationalistic. The feeling was that Shell had it coming.

"I'm not proud of how it was done," said one Russian oil worker. "Russia has lost a lot of reputation on this. But I am happy. Shell - they just don't understand how this place works."

Risks on the frontier

That Shell and its partners were victims of an unscrupulous campaign by the Russians to win leverage at the negotiating table is certainly true. The company's loss of its controlling interest in what chief executive Jeroen van der Veer called a "key part of Shell's upstream strategy," amounting to an estimated 5 percent of its global reserves, is largely a story about the high risks of frontier international energy projects. But it is also a tale of how Shell misplayed a strong hand and, after 12 years of work, lost untold billions of dollars in future earnings.

It starts with a production-sharing agreement that most observers agree was inherently unfair to Russia - a deal signed in 1996, when oil was $22 a barrel and Russia was on its knees, that gave the Shell-controlled Sakhalin Energy Investment Corp. the right to recoup all its costs plus a 17.5% rate of return before Russia would get a 10% share of the hydrocarbons coming out of the ground.

Then there was the cost of the second phase of the project, which ballooned from $10 billion in 1997 to $20 billion in 2005, fueling a perception that the company was profligate while Russians picked up the tab. The chapters in between include a calamitous safety record, a failure to meet local expectations for new roads and schools, a fuel spill in Sakhalin's third-largest city, and environmental concerns that caused anger and resentment toward Shell's leadership, earning it a reputation for stubbornness and for consistently misreading political realities.

Gallery: Scenes from Sakhalin

"Shell is always resisting," says Tom Madderom, a veteran Sakhalin contractor who has worked on the Shell project but is now employed at another site, run by Exxon Neftgas, on the northern tip of the island. "Instead of accommodating, they come out with lawyers and try to prove their case. You can run a project in Russia and have a win-win deal - even a project of this size. But it takes engaging with these people, and Sakhalin Energy hasn't been real good at it."

Take, for instance, the ire the company has drawn in Korsakov, a small weather-beaten port city on the island's southern coast, near Sakhalin Energy's Prigorodnoye LNG plant. Residents say the company led them to believe that housing for 6,000 construction workers would be located in the town, where it could later be reused by the community, which sorely needs it. Many people in Korsakov earn less than $300 a month - a sharp contrast to the wealth of Sakhalin Energy employees, many of whom, especially those who come from other countries, make more than $1,000 a day.

But when construction began, Sakhalin Energy built its housing for workers next to the plant itself, inside a one-kilometer safety zone, where it will be illegal for people to live once operations begin. "People here could use this place for their well-being, and it will be demolished," says Elena Lopukhina, director of a Korsakov advocacy group and an assistant to a regional government official, who says that is just one of the emotional issues in the community that have swayed people against Sakhalin Energy. "The company did everything that was good for them and not good for us."

Executives at Sakhalin Energy say the production-sharing agreement would have prohibited such a promise, and they maintain that these sorts of complaints are based on unrealistic hopes. "When big projects come along, expectations are always running higher than reality," says Niven. "But clearly there are also opportunities."

Local government revenue, he says, has increased fivefold, and unemployment is just over 1%. Sakhalin Energy has contributed more than $300 million so far to roads and infrastructure. And while it's too early to offer a verdict, he believes Sakhalin is on the cusp of a four-decade period of economic development. There are at least nine major oil and gas projects planned on the island, involving many of the world's largest oil companies. Shell's problem is that its project, known as Sakhalin II, is the largest of them all - and therefore the biggest target.

Much of the ammunition for Russia's political war against Sakhalin Energy comes from the cramped Yuzhno office of an independent environmental group called Sakhalin Environment Watch. At its helm is Dmitry Lisitsyn, a sharp-witted 39-year-old who has been hounding oil companies on the island for more than a decade. "We understand that our issues are being used as leverage," Lisitsyn says, "but at the same time, real problems exist."

If the government's inspections were politically fueled, though, Lisitsyn's motivations are not. He has the respect of his foes, and as Sakhalin Energy's Hilary Mercer, who heads the LNG project, puts it, "wants what is best for this place." Lisitsyn says Sakhalin II is a "lighthouse," a template for how future projects will deal with environmental and social standards. Chief among his concerns is the impact of the LNG plant, Russia's first, and the pipeline that leads to it.

The LNG plant and export terminal lie on a 1,210-acre patch of land about eight miles from Korsakov, abutting the steel-gray Aniva Bay. To the north a wide right-of-way cut in the forest marks the gas and oil pipelines' path up over the hills to the offshore platforms. To the south a jetty sticks out into the bay like a needle, ready to inject the 156 LNG tankers expected to dock there annually with liquefied gas, before sending them off to markets in the U.S., Japan, and Korea. The plant, mostly completed, won't come online until 2008, but already its output for the next 20 years is sold out.

Inside the perimeter fencing, where roughly 10,000 of Sakhalin Energy's 18,000 employees work, is - for now - the world's largest LNG facility. What happens inside the fence is by most accounts an orderly, world-class operation and a feat of engineering in Sakhalin's near-arctic conditions. It's what happens outside the fence that has drawn the scrutiny of Sakhalin Environment Watch and fomented ill will.

In order to bring LNG tankers into Aniva Bay, Sakhalin Energy had to dredge the bottom near shore, then dump the mud - two million cubic meters of it, Lisitsyn says - farther out in the bay. The island's second-largest industry after oil is fishing, and Aniva Bay is home to a diverse ecosystem that could be threatened by the dredging.

Lisitsyn wanted the company to use a longer pier, requiring less dredging, and dump the material farther out at sea. Instead Sakhalin Energy pursued the cheaper near-shore option. Now Lisitsyn is taking Sakhalin Energy to court, seeking a full accounting of environmental damages in the bay. Among other things, he alleges some of the dredging was conducted during the summer, in violation of laws protecting salmon spawning.

In that case and in disputes over the pipeline route, Lisitsyn has been highly critical of Sakhalin Energy's oil-spill preparedness and construction techniques. He says the company spends more time talking than taking action. "Sakhalin Energy loves the dialogue - it is one of their gods," he says. "But we don't want just talk, we want solutions."

Gallery: Scenes from Sakhalin

That approach has led to delays and cost increases. In 2005, Sakhalin Energy made routing adjustments to its pipeline design to minimize risk from a possible earthquake. The company says it followed proper channels, but Oleg Mitvol, deputy director for environmental inspections at the Natural Resources Ministry, told the press that the pipeline cut into a protected nature reserve, prompting him to describe Sakhalin Energy as "a pure banana republic - colonizers in cork helmets."

The following year a controversy erupted over large piles of earth left along the pipeline, which Sakhalin Environment Watch says were never permitted and which led to the temporary revocation of construction licenses last September.

"Look, this is a huge, complex, frontier type of project," says Sakhalin Energy's Niven, explaining the slew of confrontations. "We were the first company ever to put an offshore production platform in here. These are new to Russia, so the Russians themselves have had to learn how to manage and approve them."

To be sure, Shell isn't the only culprit. Russia's own oil and timber companies have been pillaging the island for resources for more than a century, and Lisitsyn says, "There is a common perception that Gazprom will be much worse." Furthermore, it was the Kremlin, not Shell, that recently cut the island's take of oil taxes from 60% to just 5%. And Sakhalin Energy deserves credit for keeping the project afloat and providing employment through a period of unprecedented economic and political change in Russia.

But to a large extent the mood on Sakhalin Island comes down to perception, not fact. Says Oleg Yugai, deputy for economic policy and budget for the regional government: "This is all about the psychology of the people."

When Shell signed the Sakhalin production-sharing agreement in 1996, the oil company had the upper hand. The oil and gas reserves on the island had been identified, and there weren't any exploration risks, but Moscow didn't have the capital to get to them. Shell and its partners did. Details about the document are sketchy, and the company won't comment. But in effect, the agreement meant that the higher the cost of the project, the longer the Kremlin would have to wait to see any royalties.

Production-sharing agreements are common in the oil industry, but the Sakhalin contract broke new ground. "This one is particularly disadvantageous to the Russian party," Ian Rutledge, an economist with Sheffield Energy & Resources Information Services, wrote in a 2004 report. "SEIC has transferred most of the risks... to the Russian government."

At the time the deal was struck, though, says Sakhalin Energy CEO Ian Craig, Russia was too volatile an investment without the framework and the fiscal regime the agreement provided. "You can debate whether [the terms] are fair or not now," he says, pointing out that the $13 billion invested to date is all shareholder-funded. "But it's a debate about dividing up a share that simply would not exist, had we not set them up then."

Russia's patience ran out in 2005, when Sakhalin Energy announced that project costs had doubled. Much of the jump can be attributed to a 20%-a-year leap in the price of labor, rising costs of materials like the steel used for pipelines, and higher oil prices. "It cost me twice as much to fly from Moscow to Yuzhno as it did two years ago," Craig says. "We're living in a $60-a-barrel world, and that applies to everything."

But even if many of the extra costs can be rationalized, frustrated residents tend to focus on the ones that can't. Sakhalin Energy is said by contractors to be spending up to $15,000 a month to house the families of some staff. When one contractor's barge ignored storm warnings to leave port and broke apart, spilling 55,000 gallons of fuel, Madderom says the tab was about $60 million, just for the boat.

[Gallery: Scenes from Sakhalin]

And when Sakhalin Energy rerouted the underwater portion of its pipeline in response to international criticism about the threat to endangered western gray whales - environmentalists say the original route was planned without thorough review - the shift cost nearly $300 million. The company says that was the pricetag for complying with environmental demands. It also denies spending extravagantly.

Still, there are the small things - the $4 pencils and $500 space heaters a customs officer says she saw listed on a Sakhalin import form, the flaunting of money by expatriate staff in downtown nightclubs, the waxed and polished Land Cruiser fleet lined up in an island parking lot - that give Sakhaliners a feeling of watching a party in their living room to which they haven't been invited.

If Sakhaliners think spending is out of control, that could explain why prices in Yuzhno also seem divorced from reality. The town stretches just a few square miles, with a neat grid of unremarkable streets bookended by a 25-foot statue of Lenin and an imposing Victory Square. The city center is for the most part architectural remnants of the communist era, while the suburbs contain acres of new middle-class housing developments - a reflection of the oil industry's impact on Sakhalin's economy. One of these houses can cost nearly $1 million, while a one-bedroom apartment can rent for $3,000 a month, comparable to New York City prices. A five-minute taxi ride costs $12, and lunch at a casual Indian restaurant starts at about $40 per person.

"I've spent time in Moscow, Tokyo, and Hong Kong," says an oil-well engineer for services company Schlumberger, who paid a $70 cover charge to walk into Yuzhno's newest nightclub, Schastie Project, only to fork over another $19 for a whiskey. "Yuzhno-Sakhalinsk is the most expensive town I've worked in."

Whether Gazprom or Shell owns Sakhalin Energy, the culture is probably not going to change. For one thing, as an analyst pointed out, Gazprom "might be omnipotent, but they still don't make LNG." That means Shell and many of its highly paid employees will stay on to manage the project, and staff may even increase as Gazprom brings in shadow workers to watch and learn.

One thing is certain, though: The deal stinks for Royal Dutch Shell, whose top executives declined to comment for this article. Its reserves will take a big hit, a tough swallow for a company already having trouble replacing its in-ground assets. Whether renegotiating a contract with a gun to its head was the smartest move for Shell is an open question. But now that the terms are settled in Russia's favor, oil majors around the world can expect their playing fields to tilt too. ■

Exhibit 15

https://www.seattletimes.com/nation-world/ocean-salmon-seasons-off-southern-oregon-coast-in-jeopardy/

Nation & World

Ocean salmon seasons in jeopardy off southern Oregon

Originally published March 5, 2018

The Associated Press

MEDFORD, Ore. (AP) — Ongoing problems with Sacramento River salmon survival means there likely will be very little, if any, sport and commercial salmon fishing this summer off the Southern Oregon coast.

Preliminary stock assessments estimate only 229,400 Sacramento River fall chinook will be in the ocean, according to federal Pacific Fishery Management Council reports. That’s 1,300 fewer than last year’s small run, whose protection shut down sport and commercial chinook fishing off Southern Oregon.

Salmon managers heading into the Pacific Fishery Management Council’s March 8-14 meeting said they think the council will be able to propose at least possible sport and commercial seasons with as little impact to Sacramento salmon stocks as possible.

Richard Heap of Brookings-Harbor, who is vice chairman of the PFMC’s salmon advisory subpanel, remains hopeful despite the numbers. “I’m going up there with the possibility that we’ll fish this year, unlike last year.

“We’ll have to wait and see how it plays out.”

The Pacific Fishery Management Council is expected to float three sport and commercial season options for public comment. Heap said he “wouldn’t be surprised” if one of those options calls for a repeat of last year when the season failed to happen, The Medford Mail Tribune reported .

The Pacific Fishery Management Council will set its final season recommendations when it meets April 5-11 in Portland. The federal Department of Commerce has the final say in setting ocean-fishing seasons.

—

Information from: Mail Tribune, http://www.mailtribune.com/

http://theworldlink.com/news/local/west-coast-senators-join-call-for-salmon-disaster-declaration/article_3690f87f-44b8-5f19-a385-7557776543b0.html

West Coast senators join call for salmon disaster declaration

SAPHARA HARRELL The Umpqua Post
Jun 13, 2017

OREGON COAST — Some Oregon and California U.S. senators are asking for a federal salmon fishery disaster declaration to support economic recovery in coastal communities in the two states after extensive commercial fishing closures due to declining salmon populations.

In April, the Pacific Fishery Management Council, a federal body that regulates commercial and sport fishing, made its 2017 salmon season recommendations. As a result, nearly half of the Oregon coast and a 130-mile section of the California coast — from Florence to Horse Mountain- is closed to commercial fishing.

In a letter written to Commerce Secretary Wilbur Ross Friday, Oregon Sens. Ron Wyden and Jeff Merkley and California Sens. Kamala Harris and Dianne Feinstein wrote that salmon catches have consistently declined over the last decade and that the disaster designation will provide a safety net to keep fishermen in business.

The senators' request follows one made by Oregon Gov. Kate Brown and California Gov. Jerry Brown, who called for a disaster declaration in a May 24 letter to Ross.

That letter stated Oregon commercial salmon fisheries are projected to make 63-percent less this year compared to the 2012-2016 average earnings of $7.3 million.

Commercial operations aren’t the only ones that will be affected.

Recreational fishing will be closed from the Oregon and California border to just south of Eureka. Last year, the Oregon recreational Chinook salmon catch was expected to be 9,000, but fell short at 4,100.

Closures are also set to impact fish processors, fishing equipment retailers, marine repair businesses, charter boat operators, bait shops and motels.

Oregon has had four disaster declarations between 2006 and 2016. A disaster declaration in 2009 resulted in $100 million of disaster-relief aid given out by NOAA’s Fisheries Service.

Michael Milstein with NOAA fisheries said the administration has known that this was going to be a difficult year for a while.

“We’ve known that it was going to be a lean year for salmon, because we know the ocean conditions have been not as productive,” Milstein said.

He said the upwelling of deep colder water that provides the fish with nutrients has been minimal the last couple of years and that has a lot to do with salmon survival.

Milstein said the Klamath River area was closed because it’s an area where a lot of fish get caught when they’re returning from the ocean.

“It’s a management area where we know a lot of those fish sustain a lot of the fishing pressure,” he said.

To protect adult salmon returning to spawn, the California the Fish and Game Commission decided to close all in-river fishing on the Klamath-Trinity watershed from Aug. 15 through the end of the year.

California Department of Fish and Wildlife’s Wade Sinnen said in an email Monday that this is the lowest projected fall Chinook abundance on record. The projected number of fish is 54,200 compared to 142,200 last year. However, he said last year's estimate wasn't reflective of the actual outcome.

"The post-season estimate for last year was 68,438, which points out that the pre-season estimates are not always precise," Sinnen said in the email.

Knute Nemeth is a retired fisherman in Charleston.

He said some local fishermen have traveled as far as Newport to fish for salmon, but it's time-consuming and expensive. Couple that with the limit on the amount of fish that can be caught and Nemeth said it has cut back on the incentive to fish for salmon at all.

Now, most salmon fishing is out of Newport.

According to the letter written by the two governors, 74-percent of the Chinook salmon caught by the Oregon commercial fishery was in Newport.

Nemeth said fishermen in the area are focusing on other fish like cod and tuna instead. But there's not always a guarantee you'll catch anything, he adds.

"Fishing is a feast or famine type of a deal and there are people with pretty skinny stomachs right now," Nemeth said.

NOAA's Milstein echoed that sentiment.

"We've known that this is a tough year for everyone and certainly it's tough for the fleet to make it through a year like this," Milstein said.

Reach Saphara Harrell at (541) 269-1222 ext. 239 or by email at saphara.harrell@theworldlink.com

Exhibit 16

Oregon Shorebird Festival
Bird List
Compiled from all field trips
August 26-28, 2011

Loons and Grebes
Red-throated Loon
Pacific Loon
Pied-billed Grebe
Western Grebe
Red-necked Grebe

Pelagic and Herons
Black-footed Albatross
South Polar Skua
Northern Fulmar
Pink-footed Shearwater
Sooty Shearwater
Buller's Shearwater
Fork-tailed Storm-Petrel
Brown Pelican
Brandt's Cormorant
Double-crested Cormorant
Pelagic Cormorant
Great Blue Heron
Great Egret
Snowy Egret
Black-crowned Night Heron

Waterfowl
Canada Goose
Mallard
Northern Pintail
Cinnamon Teal
American Wigeon
Gadwall
Ring-necked Duck
Harlequin Duck
Surf Scoter
Hooded Merganser
Bufflehead
Ruddy Duck

Birds of Prey
Turkey Vulture
Osprey
Northern Harrier
Red-shouldered Hawk
White-tailed Kite
Sharp-shinned Hawk
Cooper's Hawk
Bald Eagle
Peregrine Falcon

Rails & Bitterns
American Bittern
American Coot
Sora

Marsh and Shorebirds
Virginia Rail
Black-bellied Plover
Pacific Golden-Plover
Semipalmated Plover
Snowy Plover
Killdeer
Black Oystercatcher
Spotted Sandpiper
Baird's Sandpiper
Western Sandpiper
Least Sandpiper
Dowitcher Sp.
Greater Yellowlegs
Lesser Yellowlegs
Whimbrel
Marbled Godwit
Wandering Tattler
Black Turnstone
Surfbird
Sanderling
Wilson's Snipe
Red-necked Phalarope
Red Phalarope
*Red-necked Stint

Gulls, Terns & Alcids
Parasitic Jaeger
Long-tailed Jaeger
California Gull
Glaucous-winged Gull
Heermann's Gull
Sabine's Gull
Western Gull
Ring-billed Gull
Caspian Tern
Arctic Tern
Common Murre
Pigeon Guillemot
Marbled Murrelet
Cassin's Auklet
Rhinoceros Auklet
Tufted Puffin

Pigeons and Doves
Mourning Dove
Band-tailed Pigeon
Rock Pigeon
Eurasian Collared-dove

Owls
Great Horned Owl

Hummingbirds
Anna's Hummingbird
Rufous Hummingbird

Kingfisher
Belted Kingfisher

Woodpeckers
Downy Woodpecker
Hairy Woodpecker
Northern Flicker
Pileated Woodpecker

Flycatchers
Black Phoebe

Corvids
Steller's Jay
American Crow

Swallows
Purple Martin
Barn Swallow

Chickadees & Bushtits
Black-capped Chickadee
Chestnut-backed Chickadee
Bushtit

Wrens
Bewick’s Wren
Marsh Wren

Kinglets
Golden-crowned Kinglet

Bluebirds & Thrushes
American Robin
Swainson’s Thrush

Babblers
Wrentit

Starlings
European Starling

Waxwings
Cedar Waxwing

Warblers
Common Yellowthroat
Wilson’s Warbler

Tanagers
Western Tanager

Sparrows
Spotted Towhee
Savannah Sparrow
Song Sparrow
White-crowned Sparrow

Blackbirds
Red-winged Blackbird
Brewer's Blackbird
Brown-headed Cowbird

Finches
House Finch
American Goldfinch
Lesser Goldfinch
House Sparrow

Exhibit 17

http://www.cbc.ca/news/canada/new-brunswick/7-500-songbirds-killed-at-canaport-gas-plant-in-saint-john-1.1857615

7,500 songbirds killed at Canaport gas plant in Saint John

Migrating birds, some possible endangered species, flew into gas flare

CBC News Posted: Sep 17, 2013 1:24 PM AT ; Last Updated: Sep 18, 2013 7:48 AM AT

About 7,500 songbirds, possibly including some endangered species, were killed while flying over a gas plant in Saint John late last week, officials have confirmed.

It appears the migrating birds flew into the gas flare at Canaport LNG between Friday night and Saturday morning, said Fraser Forsythe, the company's health, safety, security and environmental manager.

The birds were drawn to the flame like moths, an extremely unusual event, according to Don McAlpine, the head of zoology at the New Brunswick Museum.

"They would circle in around that and of course with a large flame like that and high temperatures, they wouldn't need to get terribly close to become singed or burned."

The weather conditions were foggy and overcast at the time, which may have contributed to the incident, said McAlpine.

Not much is known about how such birds navigate at night, but officials believe they are attracted to light, particularly red or flashing lights, he said.

The flare tower at the Canaport liquefied natural gas receiving and regasification terminal is about 30 metres tall and the size of the flame varies, depending on weather conditions. It is typically higher amid low-pressure systems.

Flaring is part of the standard operation at the east side plant, located on Red Head Road, and is designed as a safety release system. It is used to maintain normal operating pressure by burning off small amounts of excess natural gas.

An estimated 6,800 birds were killed, while several hundred more were injured and had to be put down. "There were too many birds to count," said McAlpine.

"A crude estimate at this stage suggests about 7,500 birds died," he said. "There's certainly more than 5,000 and probably less than 10,000 birds affected."

McAlpine is still examining several hundred of the dead birds, which are being stored in a freezer, to try to identify their species.

There were a large number of red-eyed vireos, several types of warblers, including parula, black-and-white, magnolias and redstarts, as well as a few thrushes and rose-breasted grosbeaks, he said.

It's possible there may have also been some endangered species, such as the olive-sided flycatcher and Canada warbler, which are on the federal government's species at risk registry, said McAlpine.

"There are some flycatchers involved, but I haven't identified them yet. There's very few. Likewise with the Canada warbler, I haven't seen any yet, but it doesn't mean they're not there."

Many of the birds were badly burned, but some appeared completely unscathed, said McAlpine. He suspects they became disoriented and hit the tower or the ground, but several have been sent to the Atlantic Veterinary College in Prince Edward Island for necropsies to determine if there were any underlying conditions or external factors that may have contributed to the bird deaths.

The affected birds, which are mostly insect-eating, spend their summers in New Brunswick nesting and breeding before heading to Mexico, Central and South America for the winter, he said.

Staff 'reduced to tears'

Canaport LNG employees were devastated when they discovered the dead and injured birds piled up around the base of the plant's flame on Saturday morning, said Forsythe.

"We've got people that are pretty well reduced to tears here," he said.

"It has really struck home to our employees here and they've expressed a lot of remorse to me that this would happen. It's a very unexpected event," Forsythe said, adding it was the first incident of this type at the plant.

Cleanup efforts continued into Tuesday, said Forsythe.

Staff alerted the provincial Department of Environment, the Canadian Wildlife Service and the Atlantic Wildlife Institute in Sackville about the incident immediately, he said.

Barry Rothfuss, executive director of the Atlantic Wildlife Institute, said they are still busy dealing with the "carnage."

But they hope to be able to determine the cause and make recommendations to prevent a similar occurrence. "That's going to take some time," he said.

"I don't think it could have been necessarily perceived and accidents like this do happen and so it's a learning experience for all of us," Rothfuss added.

McAlpine said there is not a lot of information about bird mortalities involving flare towers.

"There's been a recognized need recently for further monitoring of this kind of thing," he said.

Still, McAlpine, said it's important to put the incident in perspective, noting an estimated one billion birds in the U.S. are killed every year from human causes.

"Although this is certainly a tragic event and it's shocking to see 7,500 dead birds, it’s a drop in the bucket in terms of the number of birds that are killed from human actions every year," said McAlpine.

The leading cause of death is birds flying into tall office buildings, while house cats rank third, he said.

Canaport LNG, owned by Repsol and Irving Oil Ltd., lists bird monitoring as among its environmental and reporting activities on its website.

Migratory birds have been considered in previous environmental impact assessments at the terminal.

In March 2012, Canaport LNG announced plans for a $43-million upgrade to make the facility more efficient and cut down on flaring.

Exhibit 18

The Irish Times
http://www.irishtimes.com/news/ireland/irish-news/gas-flaring-at-corrib-plant-frightening-says-resident-1.2482377

Gas flaring at Corrib plant 'frightening', says resident

Clip from Shell E&P Ireland showing flaring removed from YouTube on Friday night
Fri, Jan 1, 2016
By Lorna Siggins

Eyewitness footage from the Corrib gas field in Mayo captures flames lighting up the night sky on New Years Eve. Video: Tony Bourke

Residents living close to the Corrib gas plant in north Mayo have expressed alarm over the intensity of gas flaring during New Year's Eve.

Shell E&P Ireland acknowledged on Friday evening that the flaring level was "exceptional".

"As the start up process continues ,there may be further intermittent flaring activity in the coming days," it said.

"This will not be at the same level and we will take all measures to minimise any flaring occurrences,"it said.

Gas flaring at Corrib terminal filmed on December 31st, 2015

The company had advised residents on Wednesday that flaring would take place “intermittently” as gas was brought from the field 83 km offshore to land.

Valves controlling the wells at sea were opened after final operating consent for the project was issued by Minister for Energy Alex White on December 29th.

Flaring or burning off of flammable gas is activated if there is a pressure rise within the plant, or a confirmed fire or gas release.

YouTube clip

A YouTube film with John Egan of Shell E&P Ireland showing the flaring some minutes before it reached its peak, was removed from Youtube on Friday night.

In the video clip, Mr Egan was filmed against the backdrop of the flaring stack. He said it was 8pm on New Year’s Eve at Ballinaboy, and described the arrival of first gas as an “extraordinary sight” .

He said it was a “fantastic way to spend New Year’s Eve”.

The Corrib gas plant’s emissions levels are governed by an integrated pollution prevention and control licence awarded to the project last October by the Environmental Protection Agency (EPA).

At the EPA oral hearing into its original IPPC licence, Corrib’s deputy operations manager said “a small amount of gas will be flared during a start-up until the export gas composition meets the required Bord Gais specification”.

He said volumes of gas flared and vented or released into the atmosphere are “kept as low as possible to minimise environmental impact”. Flaring worldwide is a significant contributor to greenhouse gas emissions.

Residents in the areas around Ballinaboy have witnessed flaring since November 2014, during testing of the system with gas from the existing network.

‘Nothing normal’

However, Aughoose farmer Gerry Bourke, who lives about a mile from the Ballinaboy plant, said that there was “nothing normal” about Thursday night’s flaring, and said it was far more intensive and extensive than previously witnessed.

He said it “lit up the sky” and was accompanied by a “low loud rumble like a supersonic boom”.

Diane Taylor, who lives in Glengad, said she would not normally have had a view of the test flaring at the Ballinaboy stack from her home, but witnessed the New Year’s Eve incident which she described as “frightening”.

“The sky over Broadhaven Bay was pure orange, and it seemed as if thick smoke was billowing over the hill behind me,” she said. “It looked like the hill over by Pollathomas was on fire.

“It was about 8.15pm, and I opened the door and could smell smoke which would burn your nose, so I came right back inside,” Ms Taylor said. She estimated it lasted for about a half hour to 45 minutes.

Ms Taylor and neighbours subscribe to a text alert system, which Shell has invited residents to register for.

The company issued an alert on Wednesday which stated that “the valves which control the well out at the Corrib field have now been opened up” and “as part of normal start-up activities, please expect some flaring over the next 48 hours”.

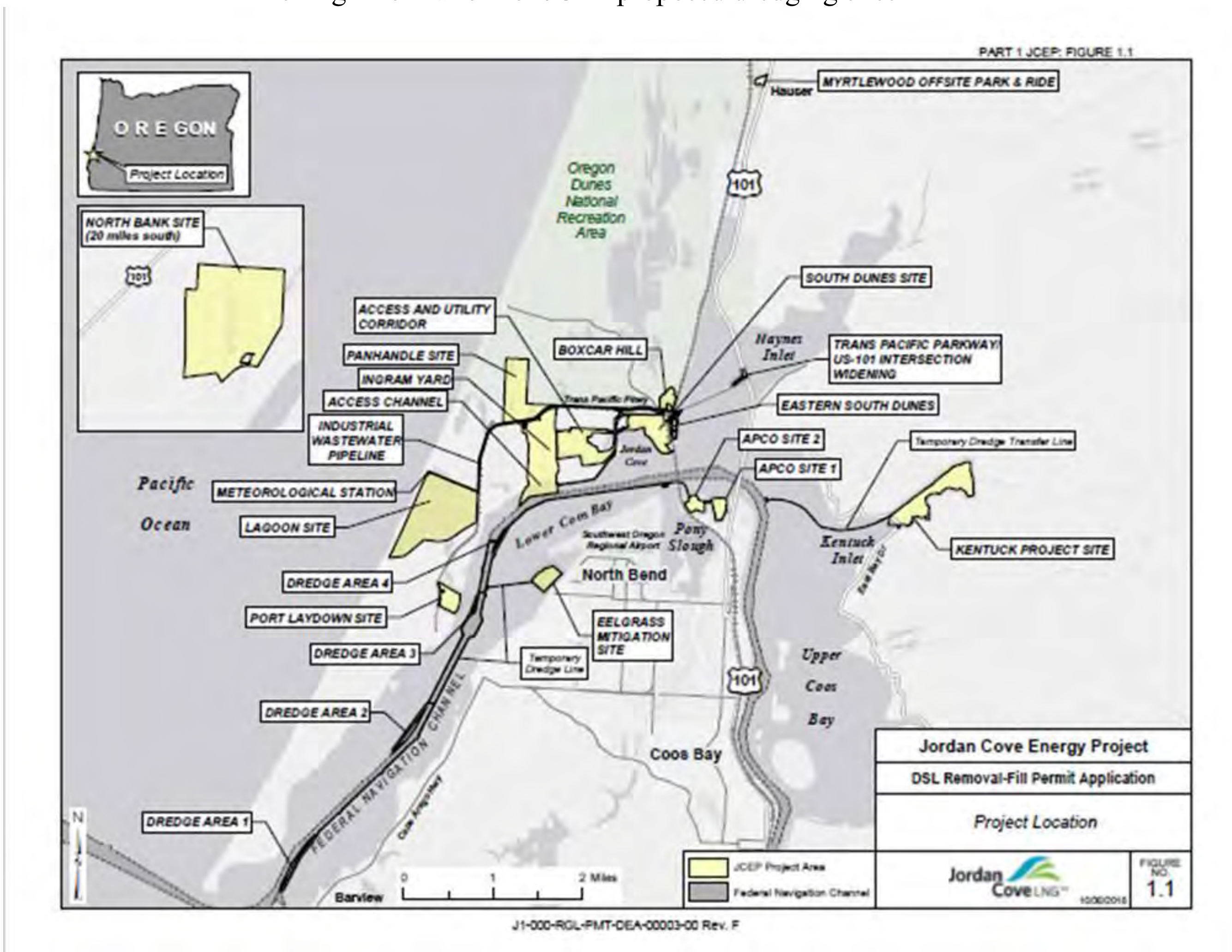
Mr Bourke said he had also received this text, but it gave no indication of the extent.

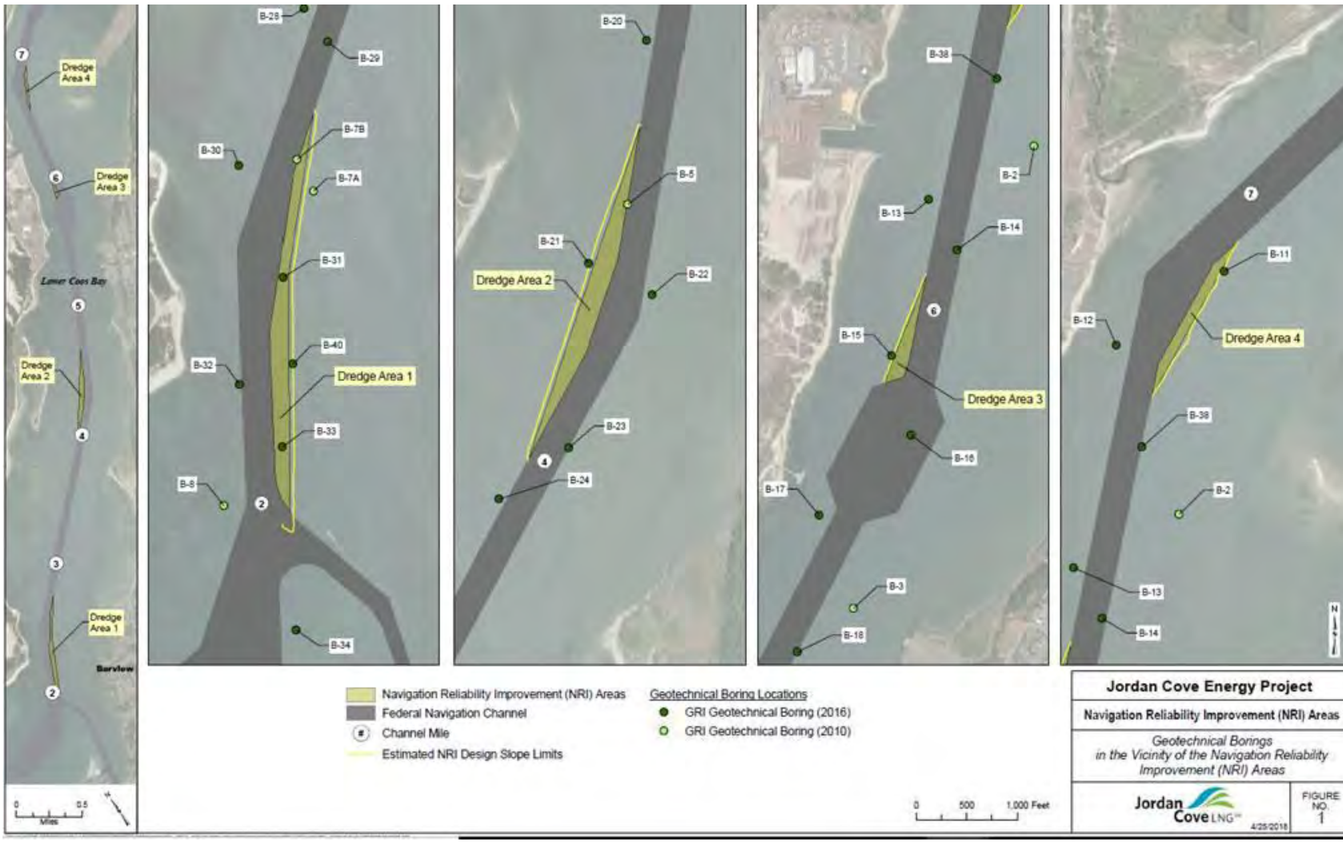
“If this is normal, as Shell is saying, I don’t want to live like this,” he said.

Flaring continued on Friday. The EPA was unavailable for comment.

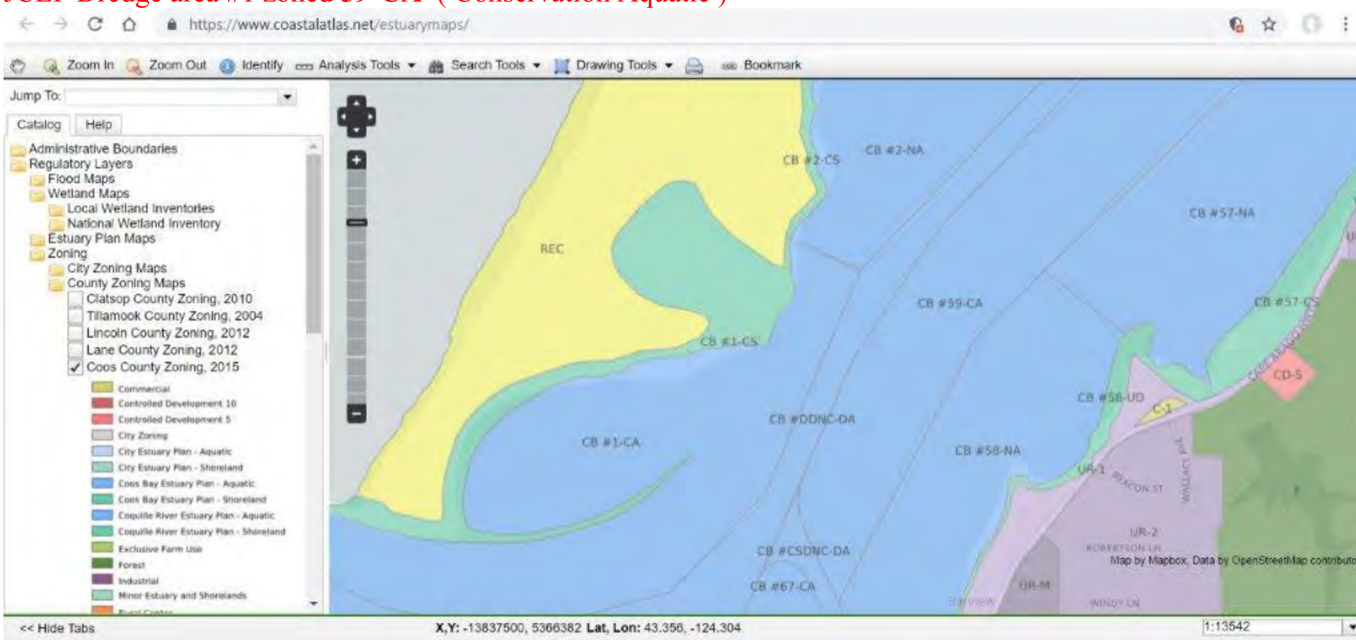
Exhibit 19

Zoning Information for JCEP proposed dredging sites




Dredge Area 4
Dredge Area 3
Lower Coos Bay
Dredge Area 2
Dredge Area 1
Barview
Dredge Area 1
Dredge Area 2
Dredge Area 3
Dredge Area 4
Navigation Reliability Improvement (NRI) Areas
Federal Navigation Channel
Channel Mile
Estimated NRI Design Slope Limits
Geotechnical Boring Locations
GRI Geotechnical Boring (2016)
GRI Geotechnical Boring (2010)
0 500 1,000 Feet
Jordan Cove Energy Project
Navigation Reliability Improvement (NRI) Areas
Geotechnical Borings in the Vicinity of the Navigation Reliability Improvement (NRI) Areas
Jordan Cove LNG
4/25/2016
FIGURE NO. 1

JCEP Dredge area #1 zoned **59-CA** (Conservation Aquatic)



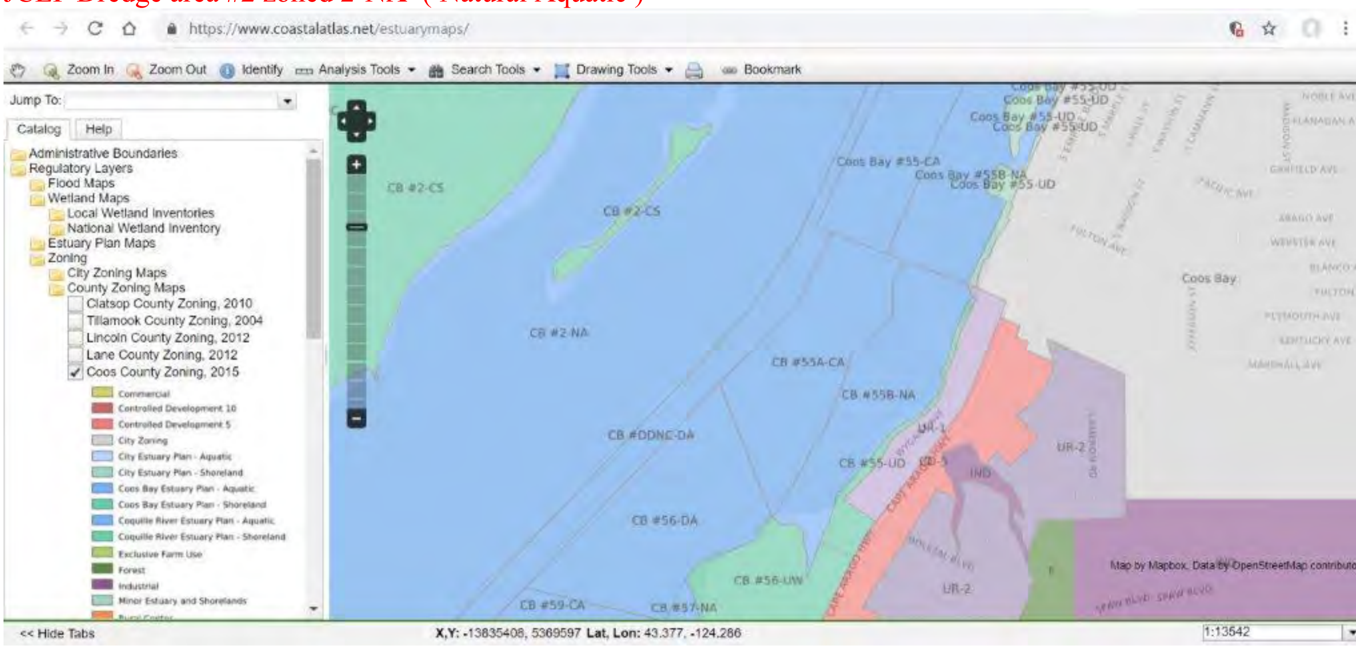
Coos County Coos Bay Estuary Management Plan Zoning District
59-CA

2. Dredging
   a. New… N [Not allowed]
   b. Maintenance dredging of existing facilities… ACU-S, G
   c. To repair dikes and tidegates… N/A

GENERAL CONDITION [G] (the following condition applies to all uses and activities):
1. Inventoried resources requiring mandatory protection in this unit are subject to Policies #17 and #18.

ACU-S
2b. This activity is only allowed subject to finding that adverse impacts have been minimized (see Policy #5); and to Policy #8 requiring mitigation.

JCEP Dredge area #2 zoned **2-NA** (Natural Aquatic)



Coos County Coos Bay Estuary Management Plan Zoning District
<u>**2-NA**</u>

2. Dredging
   a. New… N [Not allowed]
   b. Maintenance dredging of existing facilities… N
   c. To repair dikes and tidegates… N/A

JCEP Dredge area #3 zoned **3-DA** (Developmental Aquatic)

Coos County Coos Bay Estuary Management Plan Zoning District
3-DA

2. Dredging

a. New… ACU-S, G [Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions]

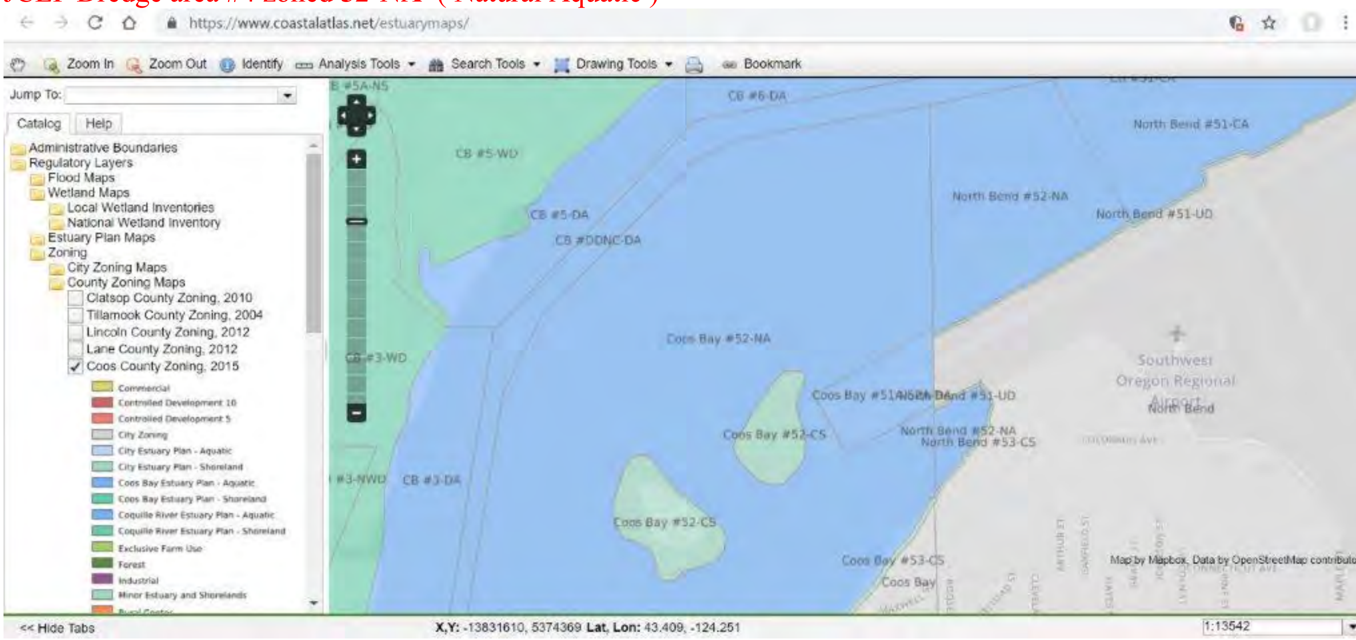
b. Maintenance dredging of existing facilities… ACU-S, G

c. To repair dikes and tidegates… N/A

GENERAL CONDITION [G] (the following condition applies to all uses and activities):
1. Inventoried resources requiring mandatory protection in this unit are subject to Policies #17 and #18.

ACU-S
2a.,2b.,3.,4.,5b.,5d. These activities are only allowed subject to finding that adverse impacts have been minimized (see Policy #5); and to Policy #8 requiring mitigation.

JCEP Dredge area #4 zoned **52-NA** (Natural Aquatic)



City of Coos Bay Estuary Management Plan Zoning District:
<u>52-NA</u>

2. Dredging
   a. New… *
   b. Maintenance Dredging of Existing Facilities… N
   c. To Repair Dikes and Tidegates… N/A

Activity
2a New dredging shall be allowed only to dredge a small channel on the north side of the proposed airport fill as necessary to maintain tidal currents. In addition, this activity is only allowed subject to a finding that adverse impacts have been minimized (see Policy #5).

JCEP Dredging area for LNG Marine Terminal zoned 6-DA (Developmental Aquatic)

Coos County Coos Bay Estuary Management Plan Zoning District

6-DA (Zoning district for JCEP Marine Terminal)

2. Dredging

a. New… ACU-S, G [Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions]

b. Maintenance dredging of existing facilities… ACU-S, G

c. to repair dikes and tidegates… N

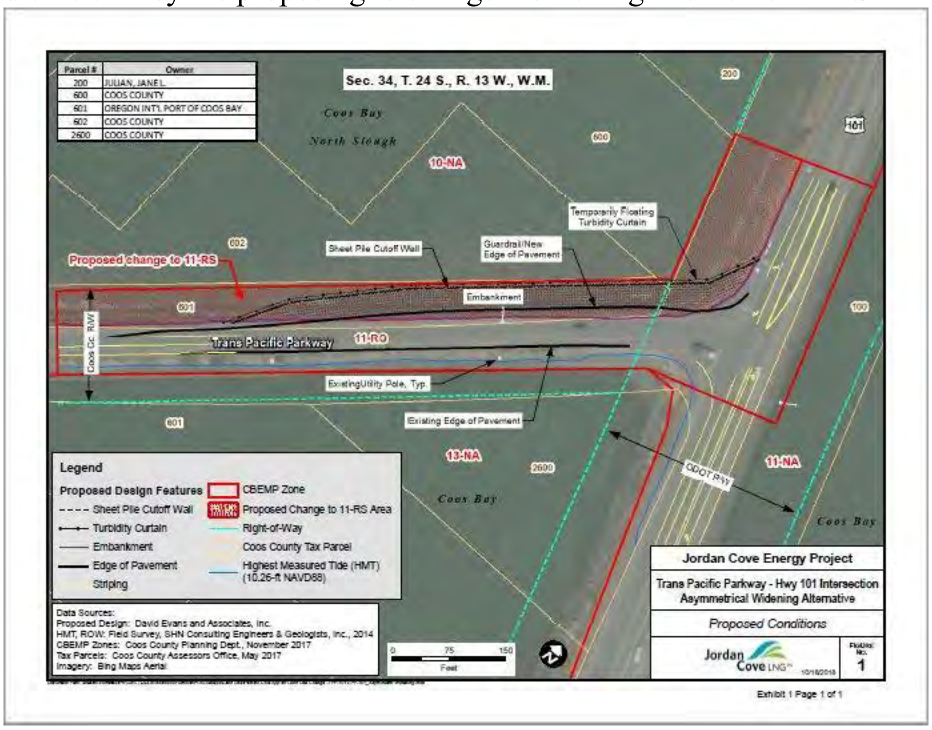
3. Dredged material disposal… N [Not allowed]

GENERAL CONDITION (the following condition applies to all uses and activities): 1. Inventoried resources requiring mandatory protection in this unit are subject to Policies #17 and #18.

2a.,2b.,5b.,5d. These activities are only allowed subject to finding that adverse impacts have been minimized (see Policy #5); and to Policy #8 requiring mitigation.

Transpacific Parkway Alignment for “Fill” in zoning district 10-NA (Natural Aquatic)

A Hearing Officer has ALREADY determined this was not an allowed use in this zoning district. They are proposing to change the Zoning District to 11-RS



Coos County Coos Bay Estuary Management Plan Zoning District:

<u>10-NA</u>

2. Dredging
    a. New… N [Not Allowed]
    b. Maintenance dredging of existing facilities… N
    c. To repair dikes and tidegates… N
3. Dredged material disposal… N [Not Allowed]
4. Fill… N [Not Allowed]

Coos County CBEMP Matrix codes – What they mean

P - means the use or activity is permitted outright subject only to the management objective.

S - indicates that the use or activity may be allowed subject to "Special Conditions" presented following the use and activity table. A few of the special conditions are non-discretionary, but most require local judgment and discretion and the development of findings to support any final decision about whether or not to allow the use or activity.

Some uses and activities may be identified as being subject to a special condition that is not discretionary or may not apply to a site-specific request. If such is the situation, the Planning Director shall make such determination and if "General Conditions" are not applicable regard the use or activity as permitted outright. Such determination shall consist of a statement of facts supporting the decision.

G - indicates the use or activity may be allowed subject to "General Conditions" presented following the use and activities table. "General Conditions" provide a convenient cross-reference to applicable Baywide Policies which may further limit or condition the uses and activities. A few "General Conditions" may not apply to a site specific request. If such is the situation, the Planning Director shall make such determination and if "Special Conditions" are not applicable, regard the use or activity as permitted outright. Such determination shall consist of a statement of facts supporting the decision.

ACU - means the use or activity may be permitted as provided above or subject to "Special" or "General" conditions pursuant to an Administrative Conditional Use.

HB - means the use or activity may be permitted except as provided above or subject to "Special" or General" conditions pursuant to a Hearings Body Conditional Use.

N - means the use or activity is prohibited.

N/A - means Not Applicable; the use or activity is not realistic considering the physical character of the district and therefore does not apply

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City of Coos Bay CBEMP Matrix Codes – What they mean (This would be for zoning district 52-NA)

3.8 USES AND ACTIVITIES MATRIX

A detailed "Uses and Activities Matrix" follows the "Management Objective" statement presented
for each respective aquatic and shoreland segment in Section 5 of this Plan. The matrix describes specific uses and activities deemed appropriate and inappropriate for each segment. To this end, the matrix further refines the "Management Objective" and Management Classification" for each segment by stipulating exactly what will and will not be allowed with each respective segment.

As policy, use and activity matrix requirements for each segment are subordinate to the "Management Objective" for the respective segments in that allowed uses and activities must be consistent with respective segments' "Management Objective" statements. (Which must in turn be consistent with Bay-wide Policies set forth in Section 3.3, above).

Interim use and activities are set forth for a few aquatic and shorelands segments. These allow temporary actions that do not preclude the ultimate use of the segment for a higher priority action - such as use as a dredged material disposal site or fulfilling mitigation/restoration projects.

Symbols denote whether or not the specific use or activity listed in the matrix is allowed, may be allowed subject to standards or special conditions or prohibited in the specific segment. The following symbols are pertinent:

"A" means the use or activity is allowed as of right, subject only to Bay-wide Policies and Management Objectives.

"*" indicates that the use or activity may be allowed subject to "Special Conditions" presented following the use and activity matrix. A few of the special conditions are non-discretionary, but most require local judgment and discretion and that development of findings to support any final decision about whether or not to allow the use or activity.

"N" means the use or activity is prohibited.

"N/A" means Not Applicable; The use or activity is not realistic considering the physical character of the segment and therefore does not apply.

In addition, "General Conditions" provide a convenient cross-reference to applicable Bay-Wide Policies which may further limit or condition allowed uses and activities in Shoreland areas.

Implementing ordinance measures are expected to further refine the general uses and activities presented in the matrices. These refinements are encouraged but must be consistent with the general matrix categories presented in the Plan.

Exhibit 20

BEFORE THE LAND USE BOARD OF APPEALS

OF THE STATE OF OREGON

OREGON SHORES CONSERVATION COALITION,
Petitioner,

and

JOHN CLARKE, DEB EVANS, RON SCHAAF,
ROGUE CLIMATE, HANNAH SOHL,
STACEY McLAUGHLIN, JODY McCAFFREE, and THE
CONFEDERATED TRIBES OF COOS, LOWER UMPQUA
and SIUSLAW INDIANS,
Intervenors-Petitioners,

vs.

COOS COUNTY,
Respondent,

and

JORDAN COVE ENERGY PROJECT L.P.,
Intervenor-Respondent.

LUBA No. 2016-095

FINAL OPINION
AND ORDER

Appeal from Coos County.

Courtney Johnson, Portland, filed the petition for review and argued on behalf of petitioner. With her on the brief was Crag Law Center.

Kathleen P. Eymann, Bandon, filed a petition for review and argued on behalf of intervenor-petitioner John Clarke.

Tonia L. Moro, Medford, filed a petition for review and argued on behalf of intervenors-petitioners Deb Evans, Ron Schaaf, Rogue Climate and Hannah Sohl.

Jody McCaffree, North Bend, filed a petition for review and argued on her own behalf.

Stacy McLaughlin, Myrtle Creek, represented herself.

Denise Turner Walsh, Carlsbad, California, filed a petition for review on behalf of intervenor-petitioner Confederated Tribes of Coos Lower Umpqua and Siuslaw Indians. Richard K. Eichstaedt argued on behalf of the Confederated Tribes.

Keith A. Leitz, Coos County Legal Counsel, Coquille, filed a response brief and argued on behalf of respondent.

Seth J. King, Portland, filed response briefs and argued on behalf of intervenor-respondent. With him on the brief was Perkins Coie LLP.

BASSHAM, Board Member; RYAN, Board Chair; HOLSTUN Board Member, participated in the decision.

REMANDED 11/27/2017

You are entitled to judicial review of this Order. Judicial review is governed by the provisions of ORS 197.850.

Opinion by Bassham.

NATURE OF THE DECISION

Petitioner appeals a county board of commissioners' decision approving a conditional use permit for a liquified natural gas (LNG) export terminal at Jordan Cove in Coos County, near the city of Coos Bay.

INTRODUCTION

Petitioner Oregon Shores and several intervenors-petitioners filed petitions for review. With minor exceptions, the five petitions for review filed do not present overlapping challenges. Therefore, we provide here only a general summary of the facts and legal context. Specific facts and legal standards relevant to particular challenges are set out under the pertinent assignments of error.

In 2015, intervenor-respondent Jordan Cove Energy Project L.P. (JCEP) applied to the county to construct an LNG export terminal at Jordan Cove, located on the North Spit at Coos Bay, located in Coos County.[1] The proposed facility would receive approximately 1.04 billion cubic feet per day of natural

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[1] JCEP had previously obtained county approvals for an LNG import terminal. *See SOPIP, Inc. v. Coos County*, 57 Or LUBA 44, *aff'd* 223 Or App 495, 196 P3d 123 (2008), and *SOPIP, Inc. v. Coos County*, 57 Or LUBA 301 (2008). The county also approved a separate application for a 49.72-mile section of a natural gas pipeline to serve the LNG import terminal. *Citizens Against LNG v. Coos County*, 63 Or LUBA 162 (2011). Various components and iterations of the project have over the years generated a number of permits and decisions from several bodies, including proceedings before the Federal Energy Regulatory Commission (FERC).

gas via pipeline, liquify the gas to produce approximately 6.8 million metric tons of LNG, and load the LNG on tanker ships for export to international or domestic markets in the non-contiguous United States.

The LNG facility consists of a number of components, including (1) the LNG export terminal, (2) a marine slip and access channel, (3) a barge berth, (4) a gas processing center, and (5) a fire station and emergency training center, along with associated roads and utilities. The project would also require significant dredging, dredge disposal, shoreline stabilization, and wetland impact mitigation.

The terminal, gas processing facility, and fire station and emergency training center will be located on upland areas zoned for industrial uses. Much of the port facilities (slip, barge berth, tugboat dock, etc.) will be located in coastal shoreland areas, which are generally zoned to allow for water-dependent uses. The marine slip and access channel will require dredging in Jordan Cove, designated a natural estuary, and Henderson Marsh, a Statewide Planning Goal 5 (Natural Resources, Scenic and Historic Areas, and Open Spaces) inventoried wetland.

The county hearings officer held a hearing on December 18, 2015, and held the record open thereafter for additional testimony and rebuttal. On May 2, 2016, the hearings officer issued a decision with recommendations to approve the applications. On August 16, 2016, the county board of commissioners held a public meeting to deliberate on the recommendations, and voted to adopt the hearings officer's findings as the county's decision, with minor modifications. The county's final decision was issued on August 30, 2016. This appeal followed.

FIRST ASSIGNMENT OF ERROR (OREGON SHORES)

The Coos Bay Estuary Management Plan (CBEMP) governs the use of the Coos Bay estuary and adjacent shorelands, implementing Statewide Planning Goal 16 (Estuarine Resources). The CBEMP designates a number of estuarine resources in the Jordan Cove area. Some are designated as "Development" zones, others as "Natural" zones in which development, including dredging and filling, is limited or prohibited.

Under the first assignment of error, petitioner Oregon Shores Conservation Coalition (Oregon Shores) cites to testimony that development of the gas processing facility will involve placement of fill in the 7-NA (Natural Aquatic) zoning district, a zone that comprises much of Jordan Cove, in which placing fill is prohibited. According to Oregon Shores, the county adopted no findings addressing the proposal to place fill in the 7-NA zone to support the gas processing facility.

Intervenor-respondent JCEP (JCEP) responds that the application did not propose placing fill anywhere in the 7-NA zone. JCEP also notes that the county rejected testimony that the application proposes to place fill in the 7-NA zone. Record 197 (findings discussing an opponents' letter "arguing, incorrectly, that the applicant's map on page 407 shows that the applicant intends to place fill in the 7-NA aquatic zone."). As far as we can tell, JCEP is correct that the application did not propose, and the decision does not approve, the placement of fill in the 7-NA zone.

The first assignment of error (Oregon Shores) is denied.

SECOND ASSIGNMENT OF ERROR (OREGON SHORES)
THIRD ASSIGNMENT OF ERROR (ROGUE INTERVENORS)[2]

The application proposes dredging within areas zoned 5-DA and 6-DA (Development Aquatic Management Units), to construct an access channel from the navigation channel to the marine slip. Such dredging is subject to CBEMP Policy 5(I),[3] which implements Goal 16, Implementation Requirement

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[2] We follow the parties in referring to intervenors-petitioners Deb Evans, Ron Schaaf, Rogue Climate, and Hannah Sohl as "Rogue Intervenors."

[3] CBEMP Policy 5(I) (Estuarine Fill and Removal) provides, in relevant part:

> "Local government shall support dredge and/or fill only if such activities are allowed in the respective management unit, and:
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> "a. The activity is required for navigation or other water-dependent use that requires an estuarine location or, in the case of fill for non-water-dependent uses, is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing, and recreation, as per ORS 541.625(4) and an exception has been taken in this Plan to allow such fill.
>
> "b. A need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights.
>
> "c. No feasible alternative upland locations exist; and

2 (Goal 16 IR2).[4] Under CBEMP Policy 5(I), dredging is allowed in the estuary only if, in relevant part, (1) it is "required for navigation or other water-dependent use that requires an estuarine location," and (2) a "need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights."

In two sub-assignments under the second assignment of error, Oregon Shores challenges the county's findings that JCEP has demonstrated that dredging required for the marine slip and access channel will (1) provide a substantial public benefit, and (2) not unreasonably interfere with public trust rights. In their third assignment of error, intervenors-petitioners Rogue Intervenors advance additional arguments under both the "substantial public benefit" and "interference with public trust rights" standards.

"d. Adverse impacts are minimized."

[4] Goal 16, Implementation Requirement 2 provides, as relevant:

"Dredging and/or filling shall be allowed only:

"a. If required for navigation or other water-dependent uses that require an estuarine location or if specifically allowed by the applicable management unit requirements of this goal; and,

"b. If a need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights; and

"c. If no feasible alternative upland locations exist; and,

"d. If adverse impacts are minimized."

A. Need/Substantial Public Benefit

Under CBEMP Policy 5(I)(a), the county found that the proposed dredging is required for a "water-dependent use that requires an estuarine location[,]" the water-dependent use being components of the LNG terminal. The Statewide Planning Goals define "water-dependent" in relevant part as "[a] use or activity which can be carried out only on, in, or adjacent to water areas because the use requires access to the water body for water-borne transportation, recreation, energy production, or source of water." *See* full quote at n 26, below. Oregon Shores does not challenge the county's finding that the LNG terminal is a "water-dependent" use for purposes of CBEMP Policy 5(I)(a) or Goal 16.[5]

With respect to CBEMP Policy 5(I)(b), Oregon Shores argues that the county misconstrued the need/substantial public benefit standard in three ways.[6] First, Oregon Shores argues that the county erred in interpreting CBEMP Policy 5(I)(b) to require evaluation only of the public benefits of the

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[5] However, as discussed below, intervenors-petitioners Rogue Intervenors challenges the conclusion that an LNG *export* terminal qualifies as a "water-dependent use" for purposes of Goal 16 and CBEMP Policy 5(I)(a).

[6] Because CBEMP Policy 5 implements Goal 16, on review the county's interpretations of the policy are not entitled to deference under ORS 197.829(1) or *Siporen v City of Medford*, 349 Or 247, 259, 243 P3d 776 (2010).

dredging activity itself, divorced from the public benefits of the land-based use that the dredging serves.[7]

We agree with Oregon Shores. If the "substantial public benefit" analysis is limited to evaluation of the public benefits of the dredge or fill activity itself, then the standard would never be met, as it is difficult to conceive of any public benefit from dredging or filling that is distinct from the use that dredging or filling serves. While the text of CBEMP Policy 5(I)(b) and Goal 16 IR2 is not entirely clear on this point, the context indicates that the four standards do not apply only to the proposed dredging or fill. We note that Goal 16 IR2(c) requires a finding that "no feasible alternative upland locations exist," which clearly contemplates evaluation of the proposed land use, not proposed dredging, since dredging does not generally take place on upland locations. We conclude that, contrary to the county's finding, CBEMP Policy 5(I)(b) requires the county to evaluate the substantiality of the public benefits provided by the use that the proposed dredging serves, in this case the LNG

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[7] The county's findings state on this point:

> "The Board concludes that the term 'need (substantial public benefit)' used in Goal 16 and CBEMP Policy #5 refers to a public benefit *for the dredging activity*, and does not require the applicant to prove that there is a public need or benefit for the underlying proposed land use (*i.e.*, a marine slip and ship terminal, or more generally, an LNG export facility.)." Record 86 (emphasis in original).

terminal, or at least those components of the terminal that are properly viewed as water-dependent uses.

Next, Oregon Shores argues that the county erred in interpreting CBEMP Policy 5(I)(b) to require evaluation only of the public benefits, and not to require any consideration of detriments or adverse impacts.[8] The county's interpretation of Policy 5(I)(b) is based on the observation that the adjoining Policy, CBEMP Policy 5(I)(a), expressly requires that the proponent of a non-water-dependent use demonstrate that there is a need for the use that "outweighs harm to navigation, fishing and recreation[.]" *See* n 3. As the findings note, this expressly required balancing test implements a statute. The county inferred that because CBEMP Policy 5(I)(b) does not expressly require a similar balancing test, the drafters of CBEMP Policy 5(I)(b) did not intend the county to engage in a similar balancing of benefits and detriments.

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[8] The county's findings state, in relevant part:

> "[T]he Board specifically rejects the argument that the [']public need/benefit' standard requires the County to balance need/benefit with (and weigh against) public detriments. In the previous sentence of Policy 5, the drafters required that an applicant for a non-water-dependent use to demonstrate that dredging and fill 'is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation.' That specific language did not come out of Goal 16, but rather is taken from ORS 196.825(4). Had the drafters of the CBEMP intended to impose a similar balancing test requirement on to the 'public need/benefit' standard, they could [] easily have done so (as they expressly did in the prior sentence), but they chose not to do so." Record 88.

As Oregon Shores argues, the question is not what the drafters of CBEMP Policy 5 intended, but what the drafters of Goal 16 IR2 intended, which CBEMP Policy 5(I)(b) implements almost verbatim. The text of Goal 16 IR2(b) does not expressly require balancing or weighing of benefits against detriments, but requires only a demonstration of a "substantial public benefit." That could be understood to represent a "net" public benefit, after consideration of both benefits and detriments. However, the fact that another implementation requirement, Goal 16 IR2(d), requires that "adverse impacts are minimized" suggests that potential adverse consequences of the proposed use are evaluated under a different standard. Given the absence of an express or a fairly implied requirement to balance or weigh benefits against adverse consequences under Goal 16 IR2(b), and the fact that adverse consequences are expressly addressed under a different standard, we decline to read Goal 16 IR(2)(b) to include an implicit requirement to balance or weigh public benefits of the proposed use against adverse consequences.

Finally, Oregon Shores challenges the county's view that the "need/substantial public benefit" standard is satisfied if the dredging activity is needed to construct a permitted or conditional use allowed on the nearby coastal shorelands or upland areas.[9] Oregon Shores argues that this

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[9] The county's findings state, in relevant part:

> "The Board believes that the 'need/substantial benefit' standard is met if the applicant demonstrates that the dredging or fill activity

interpretation conflates CBEMP Policy 5(I)(a) with 5(I)(b), and Goal 16 IR2(a) with IR2(b). According to Oregon Shores, the fact a water-dependent use is allowed on coastal shorelands under the county's zoning code does not automatically demonstrate that there is a "substantial public benefit" for purposes of CBEMP Policy 5(I)(b) and Goal 16 IR2(b).

We agree with Oregon Shores. CBEMP Policy 5(I)(a) and Goal 16 IR2(a) in relevant part require that the proposed dredging serve a water-dependent use allowed under the county's code. The county's view that the "need/substantial public benefit" standard in CBEMP Policy 5(I)(b) and Goal 16 IR2(b) is met simply by the fact that the proposed dredging serves a use allowed under the county's code, conflates CBEMP Policy 5(I)(a) and (b) and gives no independent effect to the latter. Even if the proposed dredging serves a water-dependent use allowed under the county's code, the county can allow

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is needed to enable [construction of] a permitted or condition[al] use allowed in the neighboring coastal shoreland zone and related upland zones. In other words, Coos County has, via its enactment of the CBEMP (aka: Zoning Ordinance), set forth the panoply of uses that the County believes would serve a need and/or a substantial public benefit in each particular zone (*i.e.,* it has established a list of uses that are deemed to be appropriate in each zone in question.). If the applicant is proposing one of those favored uses, and there is a need to conduct fill or dredging activity in order to facilitate that favored use, then there is, *ipso facto*, a substantial benefit to allowing the applicant to conduct that fill/removal so that it can construct and operate the use." Record 88 (emphasis in original).

the dredging only if it also finds that the use provides a substantial public benefit.

B. Interference with Public Trust Rights

CBEMP Policy 5(I)(b) and Goal 16 IR2(b) also require that the proposed dredging does not unreasonably interfere with public trust rights. The public trust doctrine protects public access to and use of navigable waters and submerged lands, for navigation, fishing and commercial uses. *See, e.g.*, *Weise v. Smith*, 3 Or 445, 450 (1869) (stating that navigable waters are "public highways" that each person has an "undoubted right to use * * * for all legitimate purposes of trade and transportation.").

1. Navigable Water

Oregon Shores first argues that the county erred by limiting the scope of public trust assets to submerged lands, and failing to include the waters overlaying those lands. JCEP responds that, while the findings cite to a circuit court case stating that the public trust doctrine protects only submerged lands, the findings in fact evaluate impacts on navigation and fishing and other uses of the navigable waters overlaying submerged lands. As discussed below, JCEP is correct that the county in fact evaluated impacts on navigation, fishing and other uses of navigable water, and did not limits its analysis to impacts on submerged lands.

2. Security Zone

Oregon Shores next challenges the county's findings regarding the impact of security zones around LNG tankers on commercial and recreational boat movements in the estuary. The application proposes that approximately 100 LNG tankers will traverse the Coos Bay Estuary to and from the LNG terminal per year. For each passage, the Coast Guard will impose a security zone extending 500 yards from the tanker in all directions, in which all other vessel movements are restricted. Oregon Shores argues that, because portions of the estuary are less than 1,000 yards wide, each tanker passage will completely halt navigation, fishing and commercial use of those portions of the estuary until the LNG tanker passes. Oregon Shores contends that the county's conclusion that the proposed security zone provisions will not unreasonably interfere with public trust rights relies on an inference from testimony in the record that is not supported by substantial evidence.

The record includes a statement from the Coast Guard that it will "allow vessels to transit the Safety/Security zone based on a case-by-case assessment conducted on scene." Record 3033. JCEP's consultant, Amergent Techs, interpreted this statement to mean that the Coast Guard would allow some boats to transit the security zone with minimal delay. Record 1817. In its findings, the county understood Amergent's testimony to be that all "known" boats would be allowed to transit the security zone without delay, presumably meaning only unknown boats will be delayed. Based on that understanding, the county concluded that tanker passage would not unreasonably interfere with navigation or public trust access to the estuary.[10]

Nothing in the record cited to us explains the distinction between a "known" and "unknown" boat. That problem aside, as Oregon Shores argues, the county's understanding that all "known" boats would be able to transit the security zone with minimal delay is not supported by the Amergent Techs memo, much less by the Coast Guard statements in the record. Neither the Amergent Techs memo nor the Coast Guard statements suggest that the Coast Guard's case-by-case evaluation would rely on a distinction between "known" and "unknown" boats, and allow the former passage through the security zone

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[10] The county's findings state, in relevant part:

> "The testimony from Amergent Techs provides clarifications regarding the limited impacts caused by LNG vessel passage and docking in Coos Bay. Importantly, the memo clarifies that the Safety/Security zones are not 'exclusion zones.' Rather, they are regulated navigation areas. Essentially, that means that the Coast Guard will control traffic near the LNG ships but will still allow boat pilots [to] transit the zone on a case-by-case basis. The Board's understanding of this explanation is that the Coast Guard will let known vessels pass but can forcibly exclude vessels or delay [vessels] that it does not recognize. As a practical matter, local commercial fishermen operating known vessels should experience no significant delays as they will receive permission from the COTP [Captain of the Port] to proceed. Less frequent users of the bay, such as recreational boaters, may experience some delay as the COTP makes efforts to identify them and conduct a threat assessment. Given that clarification, the Board believes that there will be no unreasonable interference with public trust rights. * * *" Record 100-01.

without delay, although that may well be the case. The county's findings rely on its understanding of the Amergent Techs testimony as the primary basis for its conclusion that the transit of approximately 100 LNG tankers per year through the narrow estuary will not unreasonably interfere with navigation or public trust access to the estuary. JCEP argues that there is other evidence in the record that could support that conclusion, noting testimony that delay caused to recreational or fishing vessels by an LNG vessel would last only 20-30 minutes, and that the LNG transit times would be announced in advance, so local vessels could make plans to avoid the narrow portions of the estuary at those times. Record 3764. While that evidence could lend support to a finding that LNG tanker transit will not unreasonably interfere with public trust rights, the findings do not cite that evidence, and JCEP does not argue that that evidence is sufficient, in itself, to "clearly support[]" the county's decision on this point, in the absence of adequate findings. ORS 197.835(11)(b).[11] We

[11] ORS 197.835(11)(b) provides:

> "Whenever the findings are defective because of failure to recite adequate facts or legal conclusions or failure to adequately identify the standards or their relation to the facts, but the parties identify relevant evidence in the record which clearly supports the decision or a part of the decision, the board shall affirm the decision or the part of the decision supported by the record and remand the remainder to the local government, with direction indicating appropriate remedial action."

agree with Oregon Shores that remand is necessary for the county to adopt more adequate findings, supported by substantial evidence, on this point.

3. Adverse Impacts of Climate Change

Rogue Intervenors argue in their third assignment of error that the county erred in failing to consider the adverse impacts of climate change created by LNG shipped via the LNG terminal, in evaluating whether the proposed dredging serves a use that provides "substantial public benefits" and does not unreasonably interfere with public trust rights. Rogue Intervenors contend that in evaluating both standards the county must consider the impact of greenhouse gas emissions on ocean acidification, sea level rise and other climatic changes.

We disagree with Rogue Intervenors. As discussed above, the "substantial public benefits" standard does not include an implicit requirement to balance the public benefits of the proposed LNG terminal against detriments or adverse impacts of that use, much less consider the adverse effects of greenhouse gases on climate that could be attributed to the eventual consumption of the natural gas that is shipped to markets around the world via the LNG facility. Nor have Rogue Intervenors established that the public trust doctrine requires evaluation of the contributions of greenhouse gases attributable to consumption of natural gas shipped via the terminal.

The second assignment of error (Oregon Shores) is sustained, in part.

The third assignment of error (Rogue Intervenors) is denied.

THIRD ASSIGNMENT OF ERROR (OREGON SHORES)

As noted above, CBEMP Policy 5(I)(d) allows dredging in development aquatic management units (5-DA and 6-DA) only if "[a]dverse impacts are minimized." CBEMP Policy 5(II) provides that "[i]dentification and minimization of adverse impacts as required in [Policy 5(I)(d)] shall follow the procedure set forth in Policy 4." CBEMP Policy 4(I)(d) provides in relevant part that dredging and fill in development aquatic units must be supported by findings demonstrating "the public's need and gain which would warrant any modification or loss to the estuarine system, based upon a clear presentation of the impacts of the proposed alteration, as implemented in Policy #4a."[12] CBEMP Policy 4(II) sets out standards for an impact assessment.[13] CBEMP

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[12] CBEMP Policy 4(I)(d) provides, in part"

> "Where the impact assessment requirement (of Goal #16 Implementation Requirements #1) has not been satisfied in this Plan for certain uses or activities [as identified in Policy #4] then such uses or activities shall not be permitted until findings demonstrate the public's need and gain which would warrant any modification or loss to the estuarine ecosystem, based upon a clear presentation of the impacts of the proposed alteration, as implemented in Policy #4a."

[13] CBEMP Policy 4(II) provides, in relevant part:

> "An impact assessment need not be lengthy or complex, but it should give reviewers an overview of the impacts to be expected. It may include information on:
>
> "a. the type and extent of alterations expected;

Policy 4a includes additional requirements and procedures for the impact assessment.

Oregon Shores argues that the county failed to adopt any findings addressing CBEMP Policy 4 or 4a, or provide a "clear presentation of the impacts of the proposed alteration[.]" Oregon Shores notes that the record includes an analysis of the impacts of proposed dredging, prepared by David Evans & Associates (DEA), at Record 1900-03. However, Oregon Shores argues that the county did not adopt the DEA analysis as part of its findings, and further that the DEA analysis did not follow the procedure set out in CBEMP Policy 4a.

JCEP concedes that the county did not adopt findings directly addressing CBEMP Policy 4 or 4a, but argues that the record includes evidence that "clearly supports" a finding of compliance with those policies, and therefore the decision may be affirmed on this point notwithstanding inadequate findings, pursuant to ORS 197.835(11)(b). *See* n 11. JCEP argues that the record includes ample evidence that the "public's need and gain" would

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> "b. the type of resource(s) affected;
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> "c. the expected extent of impacts of the proposed alteration on water quality and other physical characteristics of the estuary, living resources, recreation and aesthetic use, navigation, and other existing and potential uses of the estuary; and
>
> "d. the methods which could be employed to avoid or minimize adverse impacts."

warrant any modification or loss to the estuarine system, in the forms of economic gains from the proposed terminal. CBEMP Policy 4(I)(d). JCEP contends that the DEA analysis at Record 1900-03 provides the "clear presentation of the impacts" of the proposed dredging that CBEMP Policy 4 requires, and LUBA should rely on the DEA analysis to conclude that CBEMP Policy 4 is met.

The "clearly supports" standard of review at ORS 197.835(11)(b) allows LUBA to overlook nonexistent or inadequate findings only if compliance with the applicable approval standard is "obvious" or "inevitable." *Marcott Holdings v. City of Tigard*, 30 Or LUBA 101 (1995). CBEMP Policy 4 requires the county to exercise considerable subjective judgment, including identifying "the public's need and gain," and determining whether that need or gain warrants modification or loss to the estuarine system, and to ensure that impacts of the proposed alteration are minimized or mitigated. ORS 197.835(11)(b) does not authorize LUBA to affirm decisions based on LUBA's evaluation of evidence under standards such as CBEMP Policy 4, which require the exercise of significant subjective judgment. Accordingly, we agree with Oregon Shores that remand is necessary for the county to adopt findings addressing compliance with CBEMP Policy 4 and 4a.

The third assignment of error (Oregon Shores) is sustained.

FOURTH ASSIGNMENT OF ERROR (OREGON SHORES)

Proposed development in coastal shorelands, in the 6-WD (Water-Dependent Development Shorelands) and 7-D (Development Shorelands) zones, is subject to compliance with CBEMP Policy 30, which requires in relevant part that the county justify development in these areas "only upon the establishment of findings that shall include at least * * * [m]ethods for protecting the surrounding area from any adverse effects of the development[.]" CBEMP Policy 30(I)(c).[14] This language implements Statewide Planning Goal 18 (Beaches and Dunes), Implementation Requirement 1(c) (Goal 18 IR1(c)).

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[14] CBEMP Policy 30(I) provides:

> "Coos County shall permit development within areas designated as 'Beach and Dune Areas with Limited Development Suitability' on the Coos Bay Estuary Special Considerations Map only upon the establishment of findings that shall include at least:
>
> "a. The type of use proposed and the adverse effects it might have on the site and adjacent areas;
>
> "b. Temporary and permanent stabilization programs and the planned maintenance of new and existing vegetation;
>
> "c. Methods for protecting the surrounding area from any adverse effects of the development; and
>
> "d. Hazards to life, public and private property, and the natural environment which may be caused by the proposed use; and

JCEP's consultant prepared a site investigation report addressing CBEMP Policy 30(I), which identified "erosion and migration of disturbed dune sands from the site" as an adverse effect of development for purposes of CBEMP Policy 30(I)(c). To identify "methods for protecting" the surrounding beach and dune areas from those adverse impacts, the report relied on "State DEQ and FERC permits that require mitigation of erosion, re-vegetation, and monitoring of permanent stabilization measures." Record 9801.

Oregon Shores argues that the report fails to identify methods for "protecting" surrounding beaches and dunes from the identified adverse impacts. According to Oregon Shores, the term "protect[]" as used in CBEMP Policy 30(I)(c) and Goal 18 IR1(c) has the same meaning as the term "protect" as defined in the statewide planning goals, *i.e.,* "[s]ave or shield from loss, destruction, or injury for future intended use." Oregon Shores notes that LUBA has interpreted the term "protect" as used in the context of Goal 16 to require measures that will reduce the adverse impacts of development to a *de minimis* or insignificant level. *Columbia Riverkeeper v. Clatsop County*, 61 Or LUBA 96, 111, *aff'd* 238 Or App 439, 464-65, 243 P3d 82 (2010). Oregon

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> "e. Whether drawdown of groundwater would lead to loss of stabilizing vegetation, loss of water quality, or intrusion of saltwater into water supplies.
>
> "Implementation shall occur through an administrative conditional use process which shall include submission of a site investigation report by the developer that addresses the five considerations above."

Shores contends that mitigation and monitoring do nothing to reduce impacts to a *de minimis* level.

JCEP responds that the report describes more than mitigation and monitoring, but also prescribes re-vegetation and stabilization measures to reduce erosion and migration of disturbed sand. Record 9800-01. Oregon Shores does not present any argument regarding why the proposed re-vegetation and stabilization of soils are insufficient to ensure compliance with CBEMP Policy 30(I)(c). Absent a more developed argument, we agree with JCEP that Oregon Shores fails to explain why re-vegetation and stabilization measures are insufficient to satisfy CBEMP Policy 30(I)(c).

Oregon Shores also argues that the county erred in dismissing concerns raised by Oregon Shores and the State of Oregon regarding potential subsidence from dewatering activities during construction of the tank/slip facilities within the 6-WD zone. Record 7751, 8178. The county concluded that subsidence or site stability due to dewatering is not an issue that is within the scope of the only provision of the policy that explicitly addresses impacts on groundwater, CBEMP Policy 30(I)(e). *See* n 14; record 135. Oregon Shores argues, however, that subsidence due to dewatering is a potential issue under CBEMP Policy 30(I)(c), because it could constitute an "adverse effect[] of the development" on the surrounding area within the meaning of subsection (c).

JCEP responds that the county adopted an alternative finding that the proposed groundwater dewatering is "within historic levels that did not lead to the loss of stabilizing vegetation," and that Oregon Shores failed to challenge that alternative finding. Record 135. However, the quoted finding addresses "loss of stabilizing vegetation," which is an issue addressed under CBEMP Policy 30(I)(e). *See* n 14. Oregon Shores' argument is based on the language of CBEMP Policy 30(I)(c). If there are findings concluding that subsidence from proposed dewatering is not a potential issue under CBEMP Policy 30(I)(c), JCEP does not cite them. We conclude that remand is necessary to address whether subsidence is a potential issue under CBEMP Policy 30(I)(c) and, if so, adopt findings resolving that issue.

Finally, Oregon Shores argues that the finding of compliance with CBEMP Policy 30(I)(c) relies on the applicant obtaining FERC permits, but notes that FERC has denied JCEP the permits for the proposed LNG terminal. This issue is raised under the sixth assignment of error, and we address it there.

The fourth assignment of error is sustained in part.

FIFTH ASSIGNMENT OF ERROR (OREGON SHORES)

The county approved placing fill in the 7-D (Development Shorelands) zone, which is subject to "special conditions" at Coos County Land Development Ordinance (LDO) 3.2.286. Special Condition 5 states that "[t]he wetland in the southeast portion of this district can be filled for a development project contingent upon satisfaction of the prescribed mitigation described in

Shoreland District #5." The county's finding of compliance with Special Condition 5 states:

> "The Board finds that the application proposes fill in the southeast portion of this district for a development project and will mitigate in accordance with all prescribed mitigation. Therefore, the Board finds that the proposed fill is consistent with Special Condition 5." Record 70.

Oregon Shores argues that the foregoing finding is inadequate and not supported by substantial evidence, because the county failed to identify the proposed mitigation, or explain how the proposed mitigation satisfies the "prescribed mitigation described in Shoreland District #5."

JCEP does not dispute that the above-quoted finding is inadequate, but argues that no party raised any issue under Special Condition 5 during the proceedings below, and thus no party can challenge on appeal whether the county's finding of compliance with Special Condition 5 is adequate, pursuant to ORS 197.763(1).

Oregon Shores replies that a participant submitted testimony below that at one point quotes Special Condition 5 and at another point raises objections to proposed mitigation at the West Jordan Cove Mitigation Site, which is apparently where the application proposed to conduct mitigation. Record 5984. While that testimony does not advance any specific issues under Special Condition 5, it is sufficient to allow Oregon Shores to challenge the adequacy of the county's findings addressing Special Condition 5. *Lucier v. City of Medford*, 26 Or LUBA 213, 216 (1993).

On the merits, we agree with Oregon Shores that the county's only finding of compliance with Special Condition 5 is conclusory and inadequate. The findings do not identify the proposed mitigation for fill in the wetland in the southeast portion of the 7-D district, or relate it in any way to "the prescribed mitigation described in Shoreland District #5." Remand is necessary for the county to adopt more adequate findings on this point.

The fifth assignment of error (Oregon Shores) is sustained.

SIXTH ASSIGNMENT OF ERROR (OREGON SHORES)

Oregon Shores argues that the county found compliance with CBEMP Policies 5, 8 and 30 based in part on the condition that JCEP obtain and comply with state and federal permits, including FERC permits.[15] However, Oregon Shores cites testimony that on March 11, 2016, during the proceedings before the hearings officer, FERC denied JCEP's application for a permit for the proposed LNG terminal. Because the required FERC permits have been denied, Oregon Shores argues, the county erred in relying on FERC permits to demonstrate compliance with applicable approval criteria. *See Bouman v. Jackson County*, 23 Or LUBA 626, 647 (1992) (where a local government

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[15] Oregon Shores advances a similar challenge to the county's findings of compliance with CBEMP Policy 17. However, in response to intervenor's waiver challenge Oregon Shores concedes that no issues were raised below under CBEMP Policy 17. Intervenor also argues that no issues were raised below under CBEMP Policy 30, but in its reply brief Oregon Shores cites to locations in the record where issues of compliance with Policy 30 were raised.

relies on the applicant obtaining state agency permits, the record must include substantial evidence that the applicant is not precluded as a matter of law from obtaining the state agency permits).

JCEP responds that at the time of the county's decision JCEP's request for FERC to reconsider its denial was still pending, and thus the record at that time included substantial evidence that JCEP was not precluded as a matter of law from obtaining the required FERC permits. JCEP acknowledges that FERC later denied its request for reconsideration, but argues the decision denying reconsideration post-dates the county's decision and thus is not in the evidentiary record (although LUBA has taken official notice of the decision denying reconsideration). JCEP also notes that LUBA has taken official notice of the fact that JCEP has initiated a pre-filing with FERC, which is a necessary step to filing a new application for a FERC permit. Thus, JCEP argues that even if LUBA looks beyond the evidentiary record there is no reason to conclude that JCEP is precluded, as a matter of law, from obtaining FERC permits for the LNG terminal.

The county's findings observe that "[i]f it stands" FERC's March 11, 2016 permit denial decision "may very well kill the entire project, at least for the time being." Record 83. The findings note, however, that the primary basis for denial (lack of LNG contracts) could potentially be remedied, and further noted that JCEP had appealed the March 11, 2016 denial. *Id.* However, the findings do not appear to address whether or not the March 11, 2016 denial means that JCEP is precluded, as a matter of law, from obtaining FERC permits for the LNG terminal. As noted, with respect to several policies the findings expressly rely on JCEP obtaining FERC permits in order to satisfy applicable county criteria. In our view, given that the required FERC permit had, in fact, been denied during the proceeding before the county, the county erred in adopting findings of compliance with local approval standards that are unconditionally predicated on the applicant obtaining a FERC permit, without first addressing whether the denial means that JCEP is precluded, as a matter of law, from obtaining the FERC permit. Remand is necessary for the county to consider that question, and on remand the county may consider the FERC decisions or applications that post-date the county's decision in this appeal.

The sixth assignment of error (Oregon Shores) is sustained.

SEVENTH ASSIGNMENT OF ERROR (OREGON SHORES)

JCEP proposes to construct the Southwest Oregon Regional Safety Center (SORSC) on a parcel zoned for industrial and water-dependent uses.[16] The SORSC is a large "multiorganizational office complex" on eight acres that includes a fire station as one component. Record 143-44. A fire station is a permitted use in the industrial zone. Record 143. The proposed fire station would have a daily staff of four persons. Record 9826. The SORSC also

[16] Apparently, the SORSC facility is intended to meet the requirements of a 2014 Memorandum of Understanding entered into between intervenor and the State of Oregon.

includes a number of other components, including (1) offices for the Coos County sheriff, Coast Guard, and Port of Coos Bay, (2) a security center, (3) a personal safety access point (apparently a type of emergency call center), and (4) a training center for the sheriff and Southwestern Oregon Community College. Record 144. These uses would have a daily staff of approximately 12 persons. The training center includes classrooms to train up to 100 persons. Record 9826. All the latter components of the SORSC are not allowed uses in the industrial zone. However, the county approved them as "accessory uses" to the fire station.

According to the county's decision, LDO 2.1.200 defines "accessory uses" as uses that (1) are subordinate to and serve a principal use; (2) subordinate in area or purpose to that principal use; (3) contribute to the comfort, convenience, or necessity of occupants of the principal use; and (4) are located on the same unit of land as the principal use. Record 144.[17] The

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[17] The version of the LDO 2.1.200 definition of "accessory use" available on the county's website is different than the version paraphrased in the decision, perhaps reflecting an inaccurate paraphrase, or more recent amendments. The website version states:

> "ACCESSORY USE: A use, building or structure that is (1) customarily incidental and subordinate to the principal use, main building or structure, and (2) subordinate in extent, area and purpose to the principal use. A use that constitutes, in effect, conversion to a use not permitted in the district is not an accessory use."

county rejected arguments that the various SORSC components are not "subordinate" to the fire station:

> "The SORSC serves, and is subordinate in purpose to, the Fire Station because the SORSC is a training center for firefighters who will work at the Fire Station. The SORSC contributes to the comfort and convenience of the firemen who utilize the Fire Station because the SORSC offers training to current and future firefighters. * * *
>
> "* * * * *
>
> "* * * Although the SORSC will house government offices for the Coos County Sheriff, the Coast Guard, and the Port, these 'offices' are permitted in conjunction with a permitted or conditionally permitted use. [LDO] 4.4.200(26). In this regard, this is no different than a fast food restaurant that has a manager's office—the office is not a separate land use from a restaurant but is rather an inherent part of the restaurant. In this case, the offices will occur in conjunction with the Fire Station, which is a permitted use under [LDO 4.4.200(20). * * *" Record 144.

Oregon Shores argues that the county's finding that the SORSC is "subordinate" to the fire station misconstrues the applicable law and is not supported by substantial evidence. According to Oregon Shores, no reasonable person could conclude that the various government office and educational components that make up the bulk of the SORSC, including a regional training facility for up to 100 persons, are "subordinate" to a local fire station staffed by four firefighters.

JCEP responds that the county's interpretation of the code term "accessory use" is not inconsistent with the express language of that term, as defined, and must be affirmed under the deferential standard of review that

LUBA must apply to a governing body's code interpretations, under ORS 197.829(1) and *Siporen*, 349 Or at 259.[18] JCEP argues that the county viewed the SORSC office components to be an enhancement to the fire station, finding that "offices for public safety and security entities * * * will have a role in responding to fire and other natural events as service providers." Record 144. With respect to the training center, JCEP does not dispute that it will function as a training center for fire fighters and other emergency responders from around the region, not limited to training staff at the fire station, but argues that

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[18] ORS 197.829 provides:

> "1. [LUBA] shall affirm a local government's interpretation of its comprehensive plan and land use regulations, unless the board determines that the local government's interpretation:
>
> "(a) Is inconsistent with the express language of the comprehensive plan or land use regulation;
>
> "(b) Is inconsistent with the purpose for the comprehensive plan or land use regulation;
>
> "(c) Is inconsistent with the underlying policy that provides the basis for the comprehensive plan or land use regulation; or
>
> "(d) Is contrary to a state statute, land use goal or rule that the comprehensive plan provision or land use regulation implements.
>
> "2. If a local government fails to interpret a provision of its comprehensive plan or land use regulations, or if such interpretation is inadequate for review, [LUBA] may make its own determination of whether the local government decision is correct."

the LDC definition of "Accessory Uses" does not require that an accessory use serve *only* the principal use.

The county's "interpretation" is conclusory, and largely inadequate for review. The findings do not attempt to explain the meaning of "subordinate" and the other key terms in the LDO 2.1.200 definition of "accessory use," and the rationales offered for the county's conclusion are strained at best. The findings analogize the proposed government offices (sheriff, port, coast guard) to the offices for a primary business use, providing the example of an office for a restaurant. The flaw in that analogy is that the proposed government offices are not "offices" for the fire station. It may be true that staff in the government offices will occasionally provide support for the fire station, during an emergency, for example. But that is not the *function* of those government offices; any support the offices might provide to the fire station in an emergency would be, at best, ancillary to the offices' main function. Even if, as JCEP argues, the LDO 2.1.200 definition of "accessory use" does not limit an accessory use to serving *only* the primary use, it is difficult to understand how a use can be viewed as "accessory" to the primary use when any support or service it provides to the primary use is ancillary, and the purported "accessory" use has a main function that has nothing to do with the primary use.

Similarly, with respect to the regional training center, the fact that the four firefighters staffing the fire station may take classes at the 100-seat training center does little to demonstrate that the training center is "subordinate" to the fire station, under any conceivable interpretation of that term. LDO 2.1.200 requires that the accessory use be "subordinate in area or purpose to that principal use[.]" However, the findings do not discuss whether any of the SORSC components are subordinate in "area" or "purpose" to the fire station. The findings do not describe how much area is occupied by the fire station, versus the area occupied by other SORSC components, or discuss the purpose of those components, and to what extent those components "serve" the fire station, as opposed to serving other purposes.[19]

Because the findings are conclusory and do not address key language and considerations in the code definition of "accessory use," it is hard to say whether the county's conclusion that the SORSC components are accessory to the fire station embodies an interpretation of LDO 2.1.200 that is inadequate for review, or an interpretation that is simply implausible, *i.e.,* inconsistent with the express language, purpose and policy underlying LDO 2.1.200. To the extent the county's decision interprets LDO 2.1.200 to the effect that a use is "subordinate" to a primary use as long as it provides some support to the primary use, regardless of how minimal and tangential that support is compared

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[19] As far as we can tell, the findings do not discuss the proposed security center, or the personal safety access point (which we understand to be a type of emergency call center). It is possible that these uses are allowed in the industrial zone under the category of "emergency services," a permitted use that includes the proposed fire station. LDO 4.4.210(4). However, without findings about the nature of these uses, it is hard to tell.

to the putative accessory use's purpose and function, we reject the interpretation as implausible.

We do not intend to foreclose the possibility that the board of commissioners can adopt an interpretation of LDO 2.1.200 that is sustainable under the deferential standard of review we apply under ORS 197.829(1)(a), supporting a conclusion that some or all of the SORSC components are "accessory" to the fire station, as defined at LDO 2.1.200. However, the present decision includes no such interpretation. Further, any sustainable interpretation of LDO 2.1.200 must give effect to all of its applicable terms. The findings do not include an interpretation, at least one adequate for review, explaining why the proposed SORSC components are subordinate to and serve a principal use, and subordinate in area or purpose to that principal use. Or, in the words of the version of LDO 2.1.200 on the county's website, whether the SORSC uses are "customarily incidental and subordinate to the principal use," and "subordinate in extent, area and purpose to the principal use." *See* n 17. Because it may be possible on remand for the county to adopt a more sustainable interpretation under which at least some components of the SORSC can be viewed as subordinate to the fire station use, we conclude that it is appropriate to remand this issue to the county for further proceedings.

The seventh assignment of error (Oregon Shores) is sustained.

FIRST ASSIGNMENT OF ERROR (McCAFFREE)

Intervenor-petitioner Jody McCaffree (McCaffree) argues that (1) the county commission chair, Sweet, was biased in favor of the proposed LNG terminal and (2) the county commissioners failed to declare *ex parte* communications.

A. Bias

McCaffree alleges that Chair Sweet was biased in favor of the proposed LNG terminal. According to McCaffree, on April 22, 2016, Chair Sweet sent a letter, on county letterhead, to FERC expressing support for the Jordan Cove LNG terminal and Pacific Connector Pipeline Project applications then pending before FERC. Supplemental Record 527. In addition, McCaffree quotes Chair Sweet as making public statements in support of the Jordan Cove project. *Id.* at 529-30. McCaffree contends that the letter and statements demonstrate that Chair Sweet was incapable of deciding the land use application pending before the county with the requisite impartiality.

In order to succeed in a bias claim, the petitioner must first establish that the evidence of bias offered by petitioner relates to the "matter" before the tribunal. *Columbia Riverkeeper v. Clatsop County*, 267 Or App 578, 608-10, 341 P3d 790 (2014). The "matter" is "precisely and narrowly defined," as the individual land use decision that the county board of commissioners considered and decided in the local proceeding. *Id.* at 608.

Second, in order to disqualify a decision-maker from participating, a party must meet the "high bar for disqualification," demonstrating that "actual bias" has occurred, not simply an "appearance of bias." *Columbia Riverkeeper*, 267 Or App at 610; *cf. Friends of Jacksonville v. City of Jacksonville*, 42 Or LUBA 137 (2002) (finding actual disqualifying bias occurred when a city council member stated during his election campaign that he could not be objective in reviewing a pending application were he to be elected).

Finally, to demonstrate actual bias, the petitioner must establish that "the decision maker has so prejudged the particular matter as to be incapable of determining its merits on the basis of the evidence and arguments presented." *Columbia Riverkeeper*, 267 Or App at 602. To demonstrate actual bias, petitioner must identify "explicit statements, pledges, or commitments that the elected local official has prejudged the specific matter before the tribunal." *Id.* at 609-10.

We disagree with McCaffree that Chair Sweet's April 11, 2016 letter, or his public statements, demonstrate that Chair Sweet was incapable of determining the merits of the land use application based on the evidence and arguments presented. As the Court of Appeals recently explained in *Columbia Riverkeeper*, 267 Or App at 599:

> "A judge is expected to be detached, independent and nonpolitical. A county commissioner, on the other hand, is expected to be intensely involved in the affairs of the community. He is elected because of his political predisposition, not despite it, and he is expected to act with awareness of the needs of all elements of the

> county, including all government agencies charged with doing the business of the people.
>
> "* * * * *
>
> "The goal of [the *Fasano v. Washington County Commission*, 264 Or 574, 588, 507 P2d 23 (1973) impartiality requirements] is that land-use decisions should be made fairly. * * * *Fasano* cannot be applied so literally that the decision-making system is aborted because an official charged with the public duty of adjudication fears that his motivation might possibly be suspect." (Internal citations and quotation marks omitted).

As far as McCaffree has established, Chair Sweet's statements of support of the LNG terminal represent no more than the general appreciation of the benefits of local economic development that is common among local government elected officials. Those statements fall far short of demonstrating that Chair Sweet was not able to make a decision on the land use application based on the evidence and arguments of the parties.

B. *Ex Parte* Communications

McCaffree also argues that the commission erred by failing to disclose the contents of Chair Sweet's April 11, 2016 letter to FERC during the proceedings below, and by failing to disclose that Chair Sweet attended a luncheon in 2014 at which JCEP's representative offered a presentation about the proposed LNG terminal. Another commissioner, Main, also attended the luncheon, and disclosed that he had attended the luncheon and heard the presentation, which he characterized as general in nature.

ORS 215.422(3) provides:

> "No decision or action of a planning commission or county governing body shall be invalid due to ex parte contact or bias resulting from ex parte contact with a member of the decision-making body, if the member of the decision-making body receiving the contact:
>
> "(a) Places on the record the substance of any written or oral ex parte communications concerning the decision or action; and
>
> "(b) Has a public announcement of the content of the communication and of the parties' right to rebut the substance of the communication made at the first hearing following the communication where action will be considered or taken on the subject to which the communication related."

In response, JCEP argues, and we agree, that the letter from Chair Sweet to FERC does not qualify as *ex parte* contact for two reasons. First, the letter from Chair Sweet to FERC is not "*ex parte* contact" because it does not "concern[] the decision or action" made by the county commission as required by ORS 215.422(3)(a), but rather it concerns a separate decision or action by FERC. Second, the letter from Chair Sweet does not qualify as an "*ex parte* contact" because the letter was *from* Chair Sweet *to* FERC. As the text of ORS 215.422(3) indicates, the statute only governs required disclosures when the decision-maker "receiv[es] the contact." As a result, no disclosure of the April 11, 2016 letter was required pursuant to the statute.

With respect to Chair Sweet's attendance at a 2014 luncheon presentation by JCEP on the LNG project, intervenor does not dispute that Sweet failed to disclose the content of the presentation, which the other attending commissioner, Main, treated as an *ex parte* communication. It may be that the presentation does not qualify as an *ex parte* communication, or if so that Main's disclosure was sufficient for both commissioners. However, because the county's decision must be remanded for other reasons, it is appropriate to remand also to allow Chair Sweet to disclose the substance of any *ex parte* communications that occurred at the presentation.

The first assignment of error (McCaffree) is sustained, in part.

SECOND ASSIGNMENT OF ERROR (McCAFFREE)

In her second assignment of error, McCaffree argues that in the proceedings below, the county hearings officer misapplied applicable law and prejudiced McCaffree's rights due to bias against unrepresented parties. Citing to various statements by the hearings officer, McCaffree argues that the statements demonstrate a bias in favor of testimony coming from attorneys for the project applicant, over testimony from unrepresented project opponents. According to McCaffree, the hearings officer's bias against unrepresented opponents violated Statewide Planning Goal 1 (Citizen Involvement).

JCEP responds that McCaffree failed to preserve the issue by objecting before the local decision-maker. Even if the issue is preserved, JCEP argues that McCaffree has failed to demonstrate that the hearings officer was biased, or that any bias prejudiced McCaffree's procedural rights. Further, JCEP argues that McCaffree has failed to establish that any error committed by the hearings officer tainted the county commission's consideration and final decision. Finally, JCEP argues that Goal 1 is not directly applicable to the proposed permit applications.

It is not clear to us that a decision-maker's bias is properly viewed as a *procedural* error, even if evidence of the alleged bias stems from comments made by the decision-maker during a hearing. McCaffree does not identify any *procedure* that the hearings officer failed to follow. In any case, as we understand, some of the unrepresented parties below objected to the hearings officer's apparent preference for argument from represented parties.[20] To the extent preservation principles require lodging an objection to the alleged bias of the hearings officer against unrepresented parties, an objection was made.

On the merits, we have no trouble agreeing with McCaffree that the hearings officer's comments regarding the testimony were unnecessary and unfortunate. Nonetheless, we do not believe that those comments are sufficient to demonstrate that the hearings officer was biased in the sense that the hearings officer was unable to make a decision based on the arguments and evidence presented. Moreover, even if we concluded that the hearings officer was biased, JCEP is correct that the hearings officer was not the final county decision-maker. McCaffree offers no argument as to why the hearings officer's alleged bias tainted the proceedings before, or the decision of, the board of

[20] After the hearings officer expressed a preference for hearing testimony from represented parties, one participant stated: "I'm not going to waste my time [testifying before the hearings officer]. I am not an attorney and you ain't going to listen to me anyway[.]" McCaffree Petition for Review 18.

commissioners, the final decision-maker. Accordingly, McCaffree's arguments under this assignment of error do not provide a basis for reversal or remand.

The second assignment of error (McCaffree) is denied.

THIRD ASSIGNMENT OF ERROR (McCAFFREE)

In her third assignment of error, McCaffree argues that the findings adopted by the county commissioners demonstrate bias in favor of the application, because the findings generally cite and rely on evidence submitted by proponents, and ignore or erroneously discredit opposing evidence.

As an example, McCaffree argues that the county chose to rely on a report from one of JCEP's experts (Sullivan) regarding sedimentation from dredging, notwithstanding that Sullivan is a landscape architect and not an engineer, while rejecting the opponent's expert testimony (Ravens) from a licensed engineer. The Ravens testimony had been submitted in an earlier proceeding related to the LNG pipeline, but the county chose not to rely upon it in that proceeding. McCaffree submitted the Ravens testimony again in this present proceeding on the LNG terminal. According to McCaffree, the county's rejection of the Ravens testimony and reliance on a report filed by a landscape architect indicates that county decision-makers were biased in favor of the applicant.

JCEP responds that the Sullivan report was prepared by multiple authors including an environmental specialist, and a biologist. Record 1907-08. Further, JCEP argues that, while the county chided McCaffree for mischaracterizing the testimony of the opponents' engineer regarding sedimentation, the county in fact accepted and considered that testimony, and did not reject it.[21] JCEP argues that simply because the commissioners did not find the Ravens testimony persuasive does not mean that the commissioners were biased or that the Ravens testimony does not constitute substantial evidence.

Although couched as an argument regarding "bias," McCaffree's arguments can be more accurately described as a substantial evidence challenge. JCEP argues, and we agree, that McCaffree's arguments regarding how the county weighed the evidence regarding sedimentation does not demonstrate that the county was "biased" in favor of the application or, more accurately, that the county's findings regarding sedimentation are not supported by substantial evidence.

The third assignment of error (McCaffree) is denied.

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[21] The county's findings state, in relevant part:

> "On page 23 of her letter dated January 12, 2016, Ms. McCaffree cites to previously submitted testimony from Dr. Tom Ravens, and states that '[o]ur sedimentation expert actually proved [Pacific Connector] to be wrong on this issue * * *.' <u>This statement is demonstrably false</u>. In fact, the hearings officer [in a different decision] previously rejected Dr. Ravens' analysis. *See* Hearings Officer Recommendation HBCU 10-01 (Remand) at pp. 40-57, which is incorporated herein by reference." Record 107 (emphasis added).

ASSIGNMENT OF ERROR (THE TRIBES)

Intervenor-petitioner The Confederated Tribes of the Coos, Lower Umpqua & Siuslaw Indians (the Tribes) advance four sub-assignments of error, each essentially arguing that the county failed to properly apply CBEMP Policy 18, Protection of Historical, Cultural and Archaeological Sites.

CBEMP Policy 18 provides in relevant part that a development proposal involving a cultural, archeological or historical site shall include a site plan application showing all areas proposed for excavation, clearing, and construction, and submit that site plan to the Tribes for a 30-day review period.[22] The county must then conduct a review of the site plan and approve

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[22] CBEMP Policy 18 provides, in relevant part:

> "Local government shall provide protection to historical, cultural and archaeological sites and shall continue to refrain from widespread dissemination of site specific information about identified archaeological sites.
>
> "I. This strategy shall be implemented by requiring review of all development proposals involving a cultural, archaeological, or historical site to determine whether the project as proposed would protect the cultural, archaeological, and historical values of the site.
>
> "II. The development proposal, when submitted, shall include a Site Plan Application, showing, at a minimum, all areas proposed for excavation, clearing, and construction. Within three (3) working days of receipt of the development proposal, the local government shall notify [the Tribes] in writing, together with a copy of the Site Plan Application. [The Tribes] shall have the right to submit a written

or deny based in part on whether the Tribes and the applicant have agreed on "appropriate measures" to protect cultural, archeological or historical resources.[23]

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statement to the local government within thirty (30) days of receipt of such notification, stating whether the project as proposed would protect the cultural, historical, and archaeological values of the site or, if not, whether the project could be modified by appropriate measures to protect those values. [giving examples of appropriate measures]."

[23] CBEMP Policy 18 continues:

"III. Upon receipt of the statement by [the Tribes], or upon expiration of [the Tribes'] thirty day response period, the local government shall conduct an administrative review of the Site Plan Application and shall:

"a. Approve the development proposal if no adverse impacts have been identified, as long as consistent with other portions of this plan, or

"b. Approve the development proposal subject to appropriate measures agreed upon by the landowner and [the Tribes], as well as any additional measures deemed necessary by the local government to protect the cultural, historical, and archaeological values of the site. If the property owner and [the Tribes] cannot agree on the appropriate measures, then the governing body shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by preponderance of evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archaeological values of the site."

Initially, the county failed to provide notice and a 30-day comment period to the Tribes as required by CBEMP Policy 18(II). On December 18, 2015, the Tribes submitted an initial set of testimony that included information on archeological sites in the area, and noting that the Tribes had earlier designated the entirety of Jordan Cove as a site of archeological significance. The Tribes also took the position that the project would not protect the cultural and archeological values of the site, and objected that the applicant had not provided the site plan as required by CBEMP Policy18(II), which limited the Tribes' ability to provide focused objections. The county corrected its notice error and gave the Tribe 30 days to submit additional testimony, and the Tribes submitted a second set of testimony on January 12, 2016. However, the county did not initiate the administrative review process set out in CBEMP Policy 18(III), but instead apparently chose to consider the Tribes' testimony within the ongoing conditional use permit proceeding.

As noted, the county hearings officer held the only public hearing on December 18, 2015, and issued his recommendations on May 4, 2016. In his findings, later adopted by the commissioners, the hearings officer expressed skepticism about the Tribes' claim that the entirety of Jordan Cove has been designated as an archeological site, and criticized the Tribes for failing to provide site-specific objections and for failing to take a clear position on whether the proposal would protect the cultural, historical, and archaeological values of the site. With respect to the site plan required by CBEMP Policy

18(II), the hearings officer speculated that a plot plan found in the application was intended to be that site plan. Ultimately, however, the hearings officer made no findings of compliance with CBEMP Policy 18, but instead accepted JCEP's request to impose a condition of conditional use permit approval, deferring entirely consideration of CBEMP Policy 18 to a subsequent proceeding.[24] Accordingly, the county imposed Condition E.1., which provides, in its entirety:

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[24] Intervenor requested the following condition of approval:

> "Upon receipt of the statement from the Tribe(s) under CBEMP Policy 18.II, the County shall take one of the following actions: (1) if no adverse impacts to cultural, historical or archeological resources on the site have been identified, the County shall find that the Applications are consistent with CBEMP Policy 18; (2) if the Tribe(s) and the applicant reach agreement regarding the measures needed to protect the identified resources, the County shall find that the Applications are consistent with CBEMP Policy 18, subject to any additional measures the County believes are necessary to protect those resources; or (3) if the County finds that there will be adverse impacts to identified CBEMP Policy 18 resources on the site and the applicant and the Tribe(s) have not reached agreement regarding protection of such resources, then the Board of County Commissioners shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by [a] preponderance of the evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archeological values of the site. For purposes of this condition, the public hearing shall be subject to the provisions of [LDO 5.7.300] with the Board of Commissioners serving as the

> "The Board shall hold a quasi-judicial hearing to determine compliance with CBEMP Policy 18. The hearing shall be a public hearing at which the governing body shall determine by preponderance of the evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archaeological values of the site. For purposes of this condition, the public hearing shall be subject to the provisions of section 5.7.300 of the CCZLDO with the Board of Commissioners serving as the Hearings Body. The Board's decision in that matter shall constitute the Board's decision regarding the Applications' consistency with CBEMP Policy 18." Record 216.

A. Subassignments of Error A, C, and D

In these subassignments of error, the Tribes allege the county erred by deferring its CBEMP Policy 18 project review obligations by: (1) refusing to recognize and consider the Tribe's testimony regarding identified archaeological sites and districts within the project area and significant adverse impacts from the project; (2) approving the LNG Terminal without requiring the applicant to submit the site plan required by CBEMP Policy 18(II); and (3) deferring CBEMP Policy 18 determinations for an undetermined amount of time.

Hearings Body. The Board's decision in that matter shall constitute the Board's decision regarding the Applications' consistency with CBEMP Policy 18." Record 126.

1. Deferral

Because subassignments of error A, C, and D rest upon the petitioners' challenge to the county's decision to defer its CBEMP Policy 18 obligations, we begin with that issue.

The Tribes contend that, as a matter of law, the county cannot defer the procedures and determination of compliance with CBEMP Policy 18. To the extent deferral of compliance with CBEMP Policy 18 is permissible in some cases, the Tribes argue that it is not permissible in the present case.

In response, JCEP cites *Rhyne v. Multnomah County*, 23 Or LUBA 442, 447-48 (1992), for the proposition that local governments are permitted to defer a determination of compliance with a permit approval standard until a second stage in the approval process, as long as the second stage approval process provides the same notice and hearing as the initial stage:

> "Where the evidence presented during the first stage approval proceedings raises questions concerning whether a particular approval criterion is satisfied, a local government essentially has three options potentially available. First, it may find that although the evidence is conflicting, the evidence nevertheless is sufficient to support a finding that the standard is satisfied or that feasible solutions to identified problems exist, and impose conditions if necessary. Second, if the local government determines there is insufficient evidence to determine the feasibility of compliance with the standard, it could on that basis deny the application. Third, if the local government determines that there is insufficient evidence to determine the feasibility of compliance with the standard, instead of finding the standard is not met, it may defer a determination concerning compliance with the standard to the second stage. In selecting this third option, the local government is not finding all applicable approval standards are complied with,

> or that it is feasible to do so, as part of the first stage approval (as it does under the first option described above). Therefore, the local government must assure that the second stage approval process to which the decision is making is deferred provides the statutorily required notice and hearing, even though the local code may not require such notice and hearing for second stage decisions in other circumstances. *Holland v. Lane County*, 16 Or LUBA 583, 596-97 (1998)." *Id.* (Footnotes omitted).

There are several problems with JCEP's reliance on *Rhyne*. First, *Rhyne* contemplates a multi-stage approval process, where consideration of criteria that apply at the first stage can be safely deferred to the second stage, if the requisite determinations and assurances are made, because no development is possible until the final, second stage approval is obtained. However, the permit applications in the present case do not involve a multi-stage approval process. The county has, in effect, created an *ad hoc* multi-stage conditional use permit approval process, where compliance with most standards are finally determined in the first stage, leaving only compliance with one standard (CBEMP Policy 18) to be resolved at a second stage solely devoted to that purpose. That *ad hoc* approach might be permissible in some cases, with respect to some kinds of approval standards, but it requires basic assurances that Condition E.1 lacks.

Notably, nothing in Condition E.1 requires that the second stage approval be obtained prior to development, or indeed provides any assurances that there will be a second stage approval process at all. Condition E.1 is silent regarding the timing and initiation of the second stage. JCEP's request suggested that the second stage process would be initiated only when the

Tribes submitted the statement described in CBEMP Policy 18(II). *See* n 23 ("Upon receipt of the statement from the Tribe(s) * * *."). But that is not consistent with CBEMP Policy 18, which contemplates that the CBEMP Policy 18 process is initiated by the applicant filing the development application with the required site plan. The Tribes took the position that JCEP has not yet submitted the required site plan to the county, and that its efforts to provide a response to the application were hampered by the lack of the site plan. In his findings, the hearings officer identified a "plot plan" that he believed was intended to represent the site plan required by CBEMP Policy 18(II), but that issue was never resolved. Absent an adequate condition of approval that specifies how and when the CBEMP Policy 18 review process will be initiated, there is no assurance that it will ever be initiated and completed prior to development.

In addition, as a predicate to the deferral option, *Rhyne* requires that the local government determine that there is insufficient evidence to determine compliance or the feasibility of compliance with the applicable standard. *See also Gould v. Deschutes County*, 227 Or App 601, 611-12, 206 P3d 1106 (2009) (to defer a finding of compliance with first stage approval criteria to a second stage approval process, the county must find that eventual compliance with the applicable approval standards is "feasible" in the sense that the county can rule out denial as the outcome required by the hearing record). The county made none of the determinations required by either *Rhyne* or *Gould*, but simply stated that intervenor's request to defer consideration of Policy 18 "seemed reasonable." Record 126.

More fundamentally, we question whether CBEMP Policy 18 is the kind of approval standard that can be deferred. CBEMP Policy 18 is more than an approval standard, it also invokes a particular process. That process is explicitly linked to the initial development application. *See* ns 22 and 23 (requiring the county to notify the Tribes within three days of receiving the application, and providing 30 days for the Tribes to respond). CBEMP Policy 18 clearly contemplates that resolution of issues raised by the Tribes, which may change the scope, scale and footprint of the development proposal considerably, or even cause it to be denied outright, will be completed before the development is approved.

Moreover, it is important to note that CBEMP Policy 18 requires coordination with and the resolution of disputes raised by a *sovereign* government. Under CBEMP Policy 18, the Tribes are not merely another participant in the proceedings. The Tribes are entitled under CBEMP Policy 18 to special notification and consideration of issues raised, as well as the power to compel the applicant into negotiations to resolve those issues, and to compel county resolution of unsuccessfully negotiated issues. That power is considerably vitiated if the applicant can first obtain county approval of the proposed development, and only then sit down with the Tribes to negotiate changes to the approved development. Given the inertia of an existing conditional use permit approval, the county is less likely in a deferred CBEMP Policy 18 proceeding to force the applicant to accept changes to a development proposal that the county has already considered and approved. It is even less likely in such a deferred proceeding that the county would take seriously arguments that the application cannot comply with CBEMP Policy 18 and must be (retroactively) denied.

The county's findings include no interpretation of CBEMP Policy 18 explaining why it believes compliance with the policy can be deferred to a second stage proceeding, other than deferral "seemed reasonable." Record 126. It is not clear to us if the question of whether compliance with CBEMP Policy 18 can be deferred to a second stage proceeding is a matter of local or state law. Even if it is purely a matter of local law, in the absence of an adequate local interpretation, for the reasons set out above we conclude under ORS 197.829(2) that the county erred in deferring compliance with CBEMP Policy 18 to a second stage proceeding.

B. Subassignment of Error B

In this subassignment of error, the Tribes argue the county erred to the extent it rejected the Tribes' claim that the entirety of Jordan Cove is a cultural and archeological site for purposes of CBEMP Policy 18. That claim is based in part on the fact that in 2015 the Tribes designated Jordan Cove as a "significant" archaeological site under ORS 358.905(1)(b)(B).[25]

JCEP responds that the skepticism expressed in the hearings officer's findings that the entirety of Jordan Cove is a cultural or archeological site for purposes of CBEMP Policy 18 was merely nonbinding *dicta*, which would have no preclusive effect on any future proceeding to consider compliance with CBEMP Policy 18. We agree with JCEP that the challenged findings are *dicta*, given that the county completely deferred consideration of compliance with the policy to a second stage proceeding. As explained above, that deferral was erroneous, and remand is necessary for the county to conduct the proceedings required by CBEMP Policy 18, before approving the conditional use permit application. On remand, questions regarding the location and scope of archeological sites affected by the development remain issues to be resolved.

The first assignment of error (The Tribes) is sustained, in part.

FIRST ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

As noted, the application proposes development in areas designated as coastal shorelands under Statewide Planning Goal 17. OAR chapter 660, division 037 implements Goal 17 and the state policy to generally limit development of coastal shorelands to uses that are "water-dependent." The

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[25] ORS 358.905(1)(b)(B) provides that a "Site of archaeological significance" means "Any archaeological site that has been determined significant in writing by an Indian tribe."

Goals define "water-dependent" to mean "[a] use or activity which can be carried out only on, in, or adjacent to water areas because the use requires access to the water body for water-borne transportation, recreation, energy production, or source of water." Statewide Planning Goals, Definitions 8.

OAR 660-037-0040(6) provides additional definitions for purposes of the rule, which the county has implemented verbatim in LDO 2.1.200. In relevant part, OAR 660-037-0040(6)(C) defines "water-borne transportation" to mean uses of water access that fit into one of three subcategories, uses which are themselves transportation, uses which "require the receipt of shipment of goods by water," or uses which are themselves not water-borne transportation, but that are "necessary to support water-borne transportation," with the example provided of "terminal and transfer facilities."[26]

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[26] OAR 660-037-0040(6) provides, in relevant part:

"Water-Dependent Use.

"(a) The definition of 'water-dependent' contained in the Statewide Planning Goals (OAR chapter 660, division 015) applies. In addition, the following definitions apply:

"(A) 'Access' means physical contact with or use of the water.

"(B) 'Requires' means the use either by its intrinsic nature (e.g., fishing, navigation, boat moorage) or at the current level of technology cannot exist without water access.

The county concluded that the components of the LNG facility located on coastal shorelands are "water-dependent uses" as defined at LDO 2.1.200

> "(C) 'Water-borne transportation' means uses of water access:
>
> > "(i) Which are themselves transportation (e.g., navigation);
> >
> > "(ii) *Which require the receipt of shipment of goods by water*; or
> >
> > "(iii) Which are necessary to support water-borne transportation (e.g. moorage fueling, servicing of watercraft, ships, boats, etc.[, and] *terminal and transfer facilities*).
>
> "* * * * *
>
> "(b) Typical examples of water dependent uses include the following:
>
> > "(A) Industrial — e.g., manufacturing to include boat building and repair; water-borne transportation, *terminals, and support*; energy production which needs quantities of water to produce energy directly; water intake structures for facilities needing quantities of water for cooling, processing, or other integral functions.
>
> "* * * * *
>
> "(c) For purposes of this division, examples of uses that are not 'water dependent uses' include restaurants, hotels, motels, bed and breakfasts, residences, parking lots not associated with water-dependent uses, and boardwalks." (Emphasis added.)

and OAR 660-037-0040(6), because the facility involves "water-borne transportation" and is also a "terminal and support." Record 44.

On appeal, Rogue Intervenors argue that the county erred in concluding that the facility constitutes "water-borne transportation," to the extent it relied upon OAR 660-037-0040(6)(a)(C)(ii), for uses of water access "[w]hich require the receipt of shipment of goods by water[.]" Rogue Intervenors argue that "water-borne transportation" under subcategory (ii) is limited to uses related to the *import* of goods, and therefore does not include a facility dedicated to exporting LNG.

JCEP responds that Rogue Intervenors do not challenge the county's alternative conclusion that the facility is a "terminal," and therefore an express example of a water-dependent industrial use. JCEP is correct. OAR 660-037-0040(6)(a)(C)(ii) is one of three separate subcategories of uses of water access that concern "water-borne transportation." The third, OAR 660-037-0040(6)(a)(C)(iii), expressly includes "terminals and transfer facilities." *See also* OAR 660-037-0040(6)(b) (citing "terminals" as a typical example of an industrial water-dependent use). Even if the OAR 660-037-0040(6)(a)(C)(ii) subcategory is limited to import facilities, as Rogue Intervenors argue, there can be no possible dispute that a facility that loads goods onto cargo ships is a "terminal" for purposes of OAR 660-037-0040(6)(a)(C)(iii) and thus properly viewed as "water-borne transportation" for purposes of the definition of "water-dependent use."

The first assignment of error (Rogue Intervenors) is denied.

SECOND ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

The proposed LNG facility includes a 20-acre gas-processing facility, located on an industrially zoned portion of the site. The gas-processing facility first refines natural gas arriving by pipeline to remove water and carbon dioxide.[27] The refined gas is then sent through a multi-stage liquefaction process to cool and liquefy the gas. Record 18. The resulting product, LNG, is stored at a temperature of -260 degrees in large storage tanks and eventually transferred to LNG tankers via a cryogenic line. When the LNG reaches its ultimate destination, it is unloaded and converted back into gaseous form.

The industrial zone allows the processing of mineral resources as an allowed use. LDO 2.1.200 defines "Mineral Resources—Processing" as "[t]he act of refining, perfecting, or converting a natural mineral into a useful

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[27] The county's decision describes the refinement process:

> "* * * Once natural gas is transferred to the Applicant through the metering station, the gas would go through a processing plant. The processing facility would consist of two feed gas pre-treatment trains, each containing two systems in the series: a CO2 removal process which utilizes a primary amine to absorb CO2, followed by a dehydration system which uses two solid absorbents to remove water and mercury from the feed gas. The gas processing units would remove substances that would freeze during the liquefaction process, namely CO2 and water. Mercury would also be removed to prevent corrosion to downstream equipment. Trace amounts of hydrogen sulfide (H2S) would be removed as well. * * *" Record 22.

product." In this assignment of error, Rogue Intervenors argue that the county misconstrued LDO 2.1.200 in concluding that the gas-processing facility processes a mineral resource. According to Rogue Intervenors, the gas-processing facility does not convert natural gas into a "useful product," but instead takes natural gas that is of household quality, and converts it for transportation purposes only into LNG, which is not itself a "useful product." Rogue Intervenors argue that, as a matter of law, transforming a useful product into a non-useful product for transportation does not fit within the definition of "Mineral Resources—Processing" at LDO 2.1.200.

The county board of commissioners rejected that argument below:

> "* * * In its gaseous form, natural gas on the mainland of the U.S. is not a useful product for consumers living in Hawaii, for example, because there is no way to get it to that market in an unrefined form. The natural gas is refined and then converted into a liquid form so that it may be transported and used as a 'useful product' throughout the Pacific Rim." Record 141.

The county concluded that "[i]f a mineral needs to be further processed or 'perfected' to make transportation economically viable, then it follows that further processing is required to make the mineral a 'useful product' for the intended market." *Id.*

JCEP argues, and we agree, that the commissioners' interpretation of LDO 2.1.200—that processing a natural mineral into a form that allows it to be transported to markets renders that natural mineral a "useful product" for that purpose—is consistent with the express language of LDO 2.1.200's definition and accordingly must be affirmed. That the natural gas arriving at the gas-processing facility is of "household quality" and is already one form of useful product does not mean that it cannot be further processed into a different, but still useful, product, even if the usefulness of that product is to allow transportation to markets where the product will be processed further to return it to a gaseous and more useful form.

The second assignment of error (Rogue Intervenors) is denied.

FOURTH ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

Rogue Intervenors argue that the county erred in failing to impose a condition making the conditional use permit approval effective only when and if JCEP obtains all required state and federal approvals for the proposed LNG terminal, including FERC approval. In addition, Rogue Intervenors note that the gas processing facility will require a new electrical power plant, for which JCEP has not yet filed applications. Rogue Intervenors argue that the county should have made its permit decision effective only when and if the county approves the application for the new power plant.

The county's decision requires JCEP to obtain all required state and federal permits (which are required in any event by state and federal law), but does not delay the effective date of the conditional use permit approval until all required permits and approvals are obtained. JCEP responds, and we agree, that Rogue Intervenors have not identified any law that requires the county to impose a condition delaying the effectiveness of its permit approval until all other permits and approvals have been obtained. Absent a more developed argument, Rogue Intervenors' fourth assignment of error provides no basis for reversal or remand.

The fourth assignment of error (Rogue Intervenors) is denied.

FIRST ASSIGNMENT OF ERROR (CLARKE)

The proposed gas processing facility includes two "amine contactor" towers, or thermal oxidizers, that will vent heated gas into the atmosphere. The facility is located across the estuary from the Southwest Oregon Regional Airport. A portion of the LNG terminal site is within the approach surface of Runway 13, but as proposed the gas processing facility is not within the approach surface or the associated flight path.

In three sub-assignments of error, intervenor-petitioner John Clarke (Clarke) challenges the county's findings regarding compliance with LDO 4.11.445(4), which provides:

> "Industrial Emissions. No new industrial, mining or similar use * * * shall, as part of its regular operation, cause emissions of * * * steam that could obscure visibility within airport approach surfaces, except upon demonstration, supported by substantial evidence, that mitigation measures imposed as approval conditions will reduce the potential for safety risk or incompatibility with airport operations to an insignificant level. The review authority shall impose such conditions as necessary to ensure that the use does not obscure visibility."

JCEP submitted a "thermal plume" study to demonstrate compliance with LDO 4.11.445(4). The study evaluated the plumes generated by the gas processing facility, as well as the electrical power plant that is not part of this application. According to the study, the thermal oxidizers will generate only four percent of the heat plumes from both sources, and the plumes from all sources will meet applicable aviation standards. Clarke objected during the proceedings below that the thermal oxidizers will produce steam, which will obscure visibility within the airport approach surface, stating that "[b]asic physics tell you that heated air released into cool, damp air will produce steam." Record 7158. JCEP responded with a letter from Himes, a registered engineer with 46 years of experience including 10 years designing LNG facilities, who testified in relevant part that "[t]here are no visible or steam plumes from the facility." Record 3757. The county found that Himes' testimony constitutes substantial evidence and is more credible than any evidence to the contrary. Record 172.

Clarke argues that (1) Himes' statement that the thermal oxidizers will not produce visible steam plumes is not substantial evidence, given the "common knowledge" that heated air released into a cool atmosphere will produce steam; (2) although the gas processing facility is proposed to be located outside of Runway 13's surface approach area, the applicant did not seek, and the county did not approve, site plan approval, and it is possible that the gas processing facility could be moved to a location within the surface approach area; and (3) the county failed to adopt any "mitigation measures" to ensure that steam plumes will not obscure visibility within the airport surface approach area.

JCEP responds, and we agree, that Clarke's arguments do not provide a basis for reversal or remand. Himes' expert testimony is substantial evidence that the thermal oxidizers will not produce visible plumes of steam, and that testimony is not undermined by Clarke's statement, based on "common knowledge," that heated air released into cool air produces steam. In any case, LDO 4.11.445(4) is concerned only with obscured visibility within the surface approach area. Clarke's speculation that the gas processing facility could be moved from its proposed and approved location into the surface approach area is just that—speculation. JCEP proposed a specific location for the gas processing facility, and justified that facility's compliance with LDO 4.11.445(4) based in part on that proposed location, outside the surface approach area. Clarke does not explain how the gas processing facility could be relocated from that approved location west to a site within the surface approach area without modifying the conditional use permit or otherwise triggering evaluation under LDO 4.11.445(4)

The first assignment of error (Clarke) is denied.

The county's decision is remanded.

Exhibit 21

Coos County Planning Department
Land Use Application

FEE: $1450	Official Use Only
Receipt No. 189256	
Check No./Cash 1444	
Date 3/9/17	
Received By D. Brown	
File No. ACU-17-009	

Please place a check mark on the appropriate type of review that has been requested.

- [X] Administrative Review
- [ ] Hearings Body Review
- [ ] Final Development Plan (BDR)
- [ ] Variance

An **incomplete** application **will not** be processed. Applicant is responsible for completing the form and addressing all criteria. Attach additional sheets to answer questions if needed. Please indicated not applicable on any portion of the application that does not apply to your request.

A. Applicant:

Name: Oregon Dunes Sand park, LLC Telephone (541) 290-0463
Address: PO. Box 97
City: Coos Bay State: OR Zip Code: 97420

B. Owner:

Name: Oregon Dunes Sand park, LLC Telephone: (541) 290-0463
Address: 92799 Trans Pacific Parkway
City: North Bend State: OR Zip Code: 97459

C. As applicant, I am (check one): Please provide documentation.

- [X] The owner of the property (shown on deed of record);
- [ ] The purchaser of the property under a duly executed written contract who has the written consent of the vendor to make such application (consent form attached).
- [ ] A lessee in possession of the property who has written consent of the owner to make such application (consent form attached).
- [ ] The agent of any of the foregoing who states on the application that he/she is the duly authorized agent and who submits evidence of being duly authorized in writing by his principal (consent form attached).

D. Description of Property:

Township 24 / 24 Range 13 / 13 Section 34B / 34C Tax Lot 1400; 1500; 1600 / 1600; 1700
Tax Account 185603 / 185801 / 185604 & ~~185601 / 185607~~ Lot Size 17.60 / 3.53 / 6.30 / 37.50 / 19.45 Zoning District Ind

Updated 2016

E. Information (please check off as you complete)

- ☐ 1. Project Proposal. Attach description if needed. Expand existing RV park
- ☐ 2. A detailed parcel map of the subject property illustrating the size and location of existing and proposed uses, structures and roads on an 8½" x 11" paper to scale. Applicable distances must be noted on the parcel map along with slopes. (See example plot map)Covenants or deed restrictions on the property, if unknown contact title company.
- ☐ 3. Existing Use High Density Recreation / RV park / Sand Sports / ATV Rentals
- ☐ 4. Site Address 92799 Trans pacific Parkway, North Bend, OR 97459
- ☐ 5. Access Road Trans pacific Parkway
- ☐ 6. Is the Property on Farm/Forest Tax Deferral NO
- ☐ 7. Current Land Use (timber, farming, residential, etc.) Recreation
- ☐ 8. Major Topography Features (streams, ditches, slopes, etc.) Sand Dunes
- ☐ 9. List all lots or parcels that the current owner owns, co-owns or is purchasing which have a common boundary with the subject property on an assessment map.
- ☐ 10. Identify any homes or development that exists on properties identified in #9.
- ☐ 11. A copy of the current deed of record.

F. Proposed use and Justification

Please attach an explanation of the requested proposed use and **findings (or reasons)** regarding how your application and proposed use comply with the following the Coos County Zoning and Land Development Ordinance (LDO). Pursuant to the LDO, this application may be approved only if it is found to comply with the applicable criteria for the proposed use. Staff will provide you with the criteria; however, staff cannot provide you with any legal information concerning the adequacy of the submitted findings, there is no guarantee of approval and the burden rests on the applicant. (You may request examples of a finding)

☐ **List of Applicable Criteria and Justification:**

*see attached

LDO Proposed Use and Justification for Expansion of Box Car Hill Campground

92799 Trans Pacific Parkway, North Bend, Or. 97459

The Box Car Hill Campground has experienced tremendous growth since opening in 2012. We are the only privately owned full service destination RV Park Resort with a sand drag strip, store, gas, ATV Rental sales & repairs that enjoys direct access to the Oregon Dunes National Recreation Area. Our dune sand drag strip is the only one operating on the West Coast. We have hosted many group events for off road enthusiasts such as Sand Fest, Summer Fest & UTV Takeover.

These events are covered by several off road magazines and attract participants from Canada to the Mexican Border. The positive impact and exposure for our area undoubtedly benefits many of our friends in Coos Bay & North Bend. Our customers shop, eat at restaurants, gamble and plan return trips due to the convenience of our facility and its close proximity to town.

Unfortunately, we have turned down several major events due to not having enough sites to meet an event organizer's requirements. Our local area has lost out on considerable economic benefit from these events having to go elsewhere, like Winchester Bay, Sand Lake, or even out of state to California and Idaho.

Presently, we are working with the organizers of UTV Takeover to hold a Father's Day Event that will attract 600-750 people. In order to accommodate this event, the UTV Takeover Group has gained permission from Jordan Cove LNG to use the old Weyco Paper Mill Site and USFS to offer additional dry camping during this 4 day event. Go to www.utvtakeover.com and click on the camping tab to see the positive economic impact this event will have on our community.

In summary, our original application & plan envisioned RV camping sites, sand sport activities and complementary commercial operations. The only development goal in our original plan application we haven't completed yet are Zip lines. Due to the high demand for camping sites during the peak summer season, we have consistently sold out on weekends and all holidays. Demand dictates we expand or risk continual loss of business for ourselves and our community.

G. Authorization:

All areas must be initialed by all applicant(s) prior to the Planning Department accepting any application unless the statement is not applicable. If one of the statements, below is not applicable to your request indicated by writing N/A.

I hereby attest that I am authorized to make the application for a conditional use and the statements within this application are true and correct to the best of my knowledge and belief. I affirm that this is a legally created tract, lot or parcel of land. I understand that I have the right to an attorney for verification as to the creation of the subject property. I understand that any action authorized by Coos County may be revoked if it is determined that the action was issued based upon false statements or misrepresentation.

ORS 215.416 Permit application; fees; consolidated procedures; hearings; notice; approval criteria; decision without hearing. (1) When required or authorized by the ordinances, rules and regulations of a county, an owner of land may apply in writing to such persons as the governing body designates, for a permit, in the manner prescribed by the governing body. The governing body shall establish fees charged for processing permits at an amount no more than the actual or average cost of providing that service. The Coos County Board of Commissioners adopt a schedule of fees which reflect the average review cost of processing and set-forth that the Planning Department shall charge the actual cost of processing an application. Therefore, upon completion of review of your submitted application/permit a cost evaluation will be done and any balance owed will be billed to the applicant(s) and is due at that time. By signing this form you acknowledge that you are responsible to pay any debt caused by the processing of this application. Furthermore, the Coos County Planning Department reserves the right to determine the appropriate amount of time required to thoroughly complete any type of request and, by signing this page as the applicant and/or owner of the subject property, you agree to pay the amount owed as a result of this review. If the amount is not paid within 30 days of the invoice, or other arrangements have not been made, the Planning Department may choose to revoke this permit or send this debt to a collection agency at your expense.

I understand it is the function of the planning office to impartially review my application and to address all issues affecting it regardless of whether the issues promote or hinder the approval of my application. In the event a public hearing is required to consider my application, I agree I bear the burden of proof. I understand that approval is not guaranteed and the applicant(s) bear the burden of proof to demonstrate compliance with the applicable review criteria.

As applicant(s) I/we acknowledge that is in my/our desire to submit this application and staff has not encouraged or discouraged the submittal of this application.

R. Todd Goergen

Applicant(s) Original Signature

Applicant(s) Original Signature

R. TODD GOERGEN

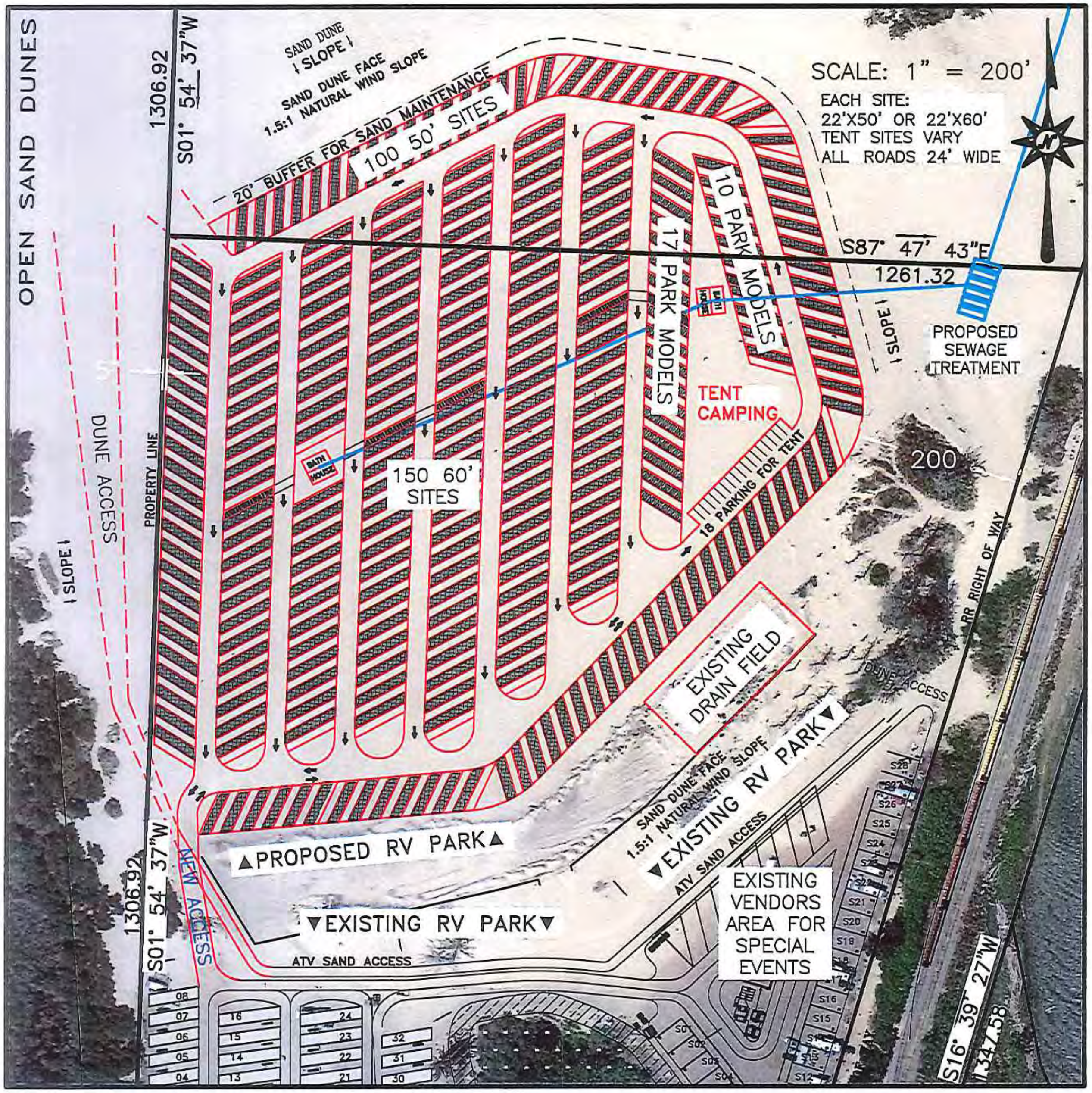
Print Name

Print Name

Updated 2016

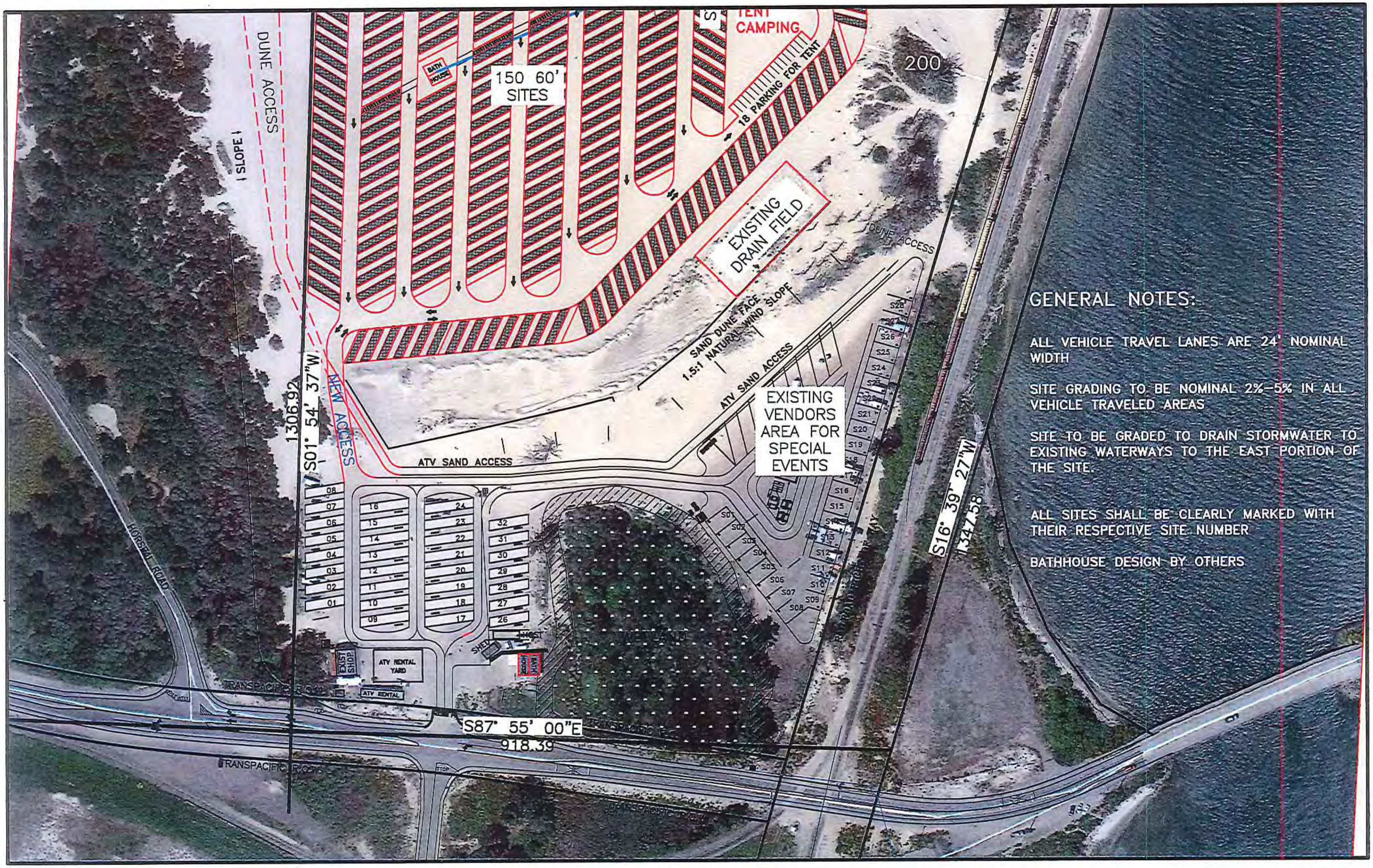
BOXCAR HILL CAMPGROUND
Site Layout & Vicinity Map
PHASE II 14.2 ACRE EXPANSION
SEC. 34, T.24S.,R.13W., W.M., COOS COUNTY, OREGON

PREPARED FOR:
TODD GOERGEN
OREGON DUNES SANDPARK, LLC
P.O. BOX 97
COOS BAY, OREGON 97420
PHONE 541-290-0463



PROJECT LOCATION

Stuntzner Engineering & Forestry, LLC ENGINEERING * LAND SURVEYING * FORESTRY LAND PLANNING * WATER RIGHTS	705 SOUTH 4TH STREET P.O. BOX 118 COOS BAY, OREGON 97420	PHONE: (541) 267-2872 FAX: (541) 267-0588 www.stuntzner.com	SITE LAYOUT JOB NAME: BOX CAR CAMPGROUND DATE: MARCH 6, 2017 JOB NO: 1112004 DESIGN BY: MEK PAGE: 1 OF 3 DRAWN BY: MEK

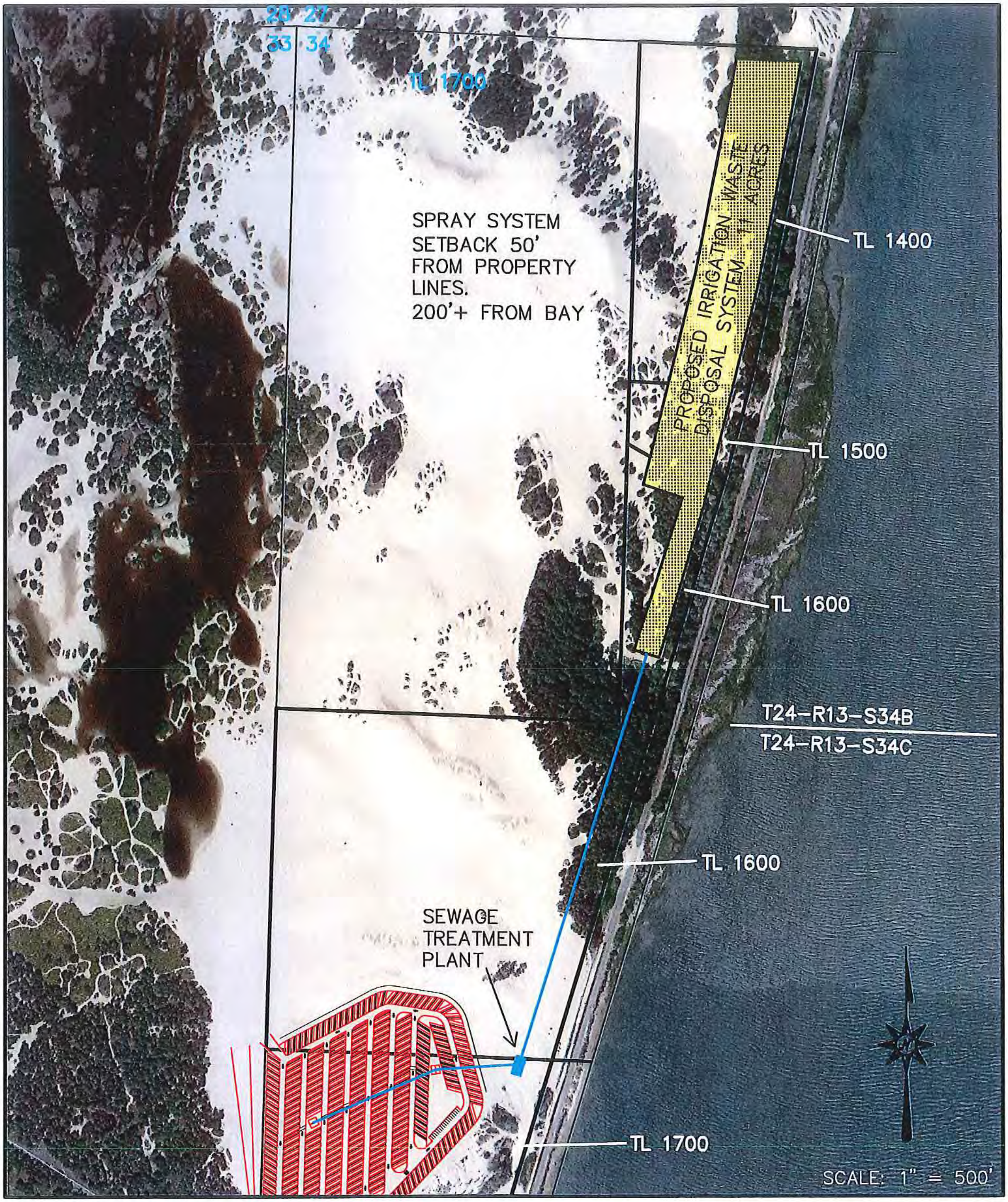


Stuntzner Engineering & Forestry, LLC
ENGINEERING * LAND SURVEYING * FORESTRY
LAND PLANNING * WATER RIGHTS

705 SOUTH 4TH STREET
P.O. BOX 118
COOS BAY, OREGON 97420

PHONE: (541) 267-2872
FAX: (541) 267-0588
www.stuntzner.com

SITE LAYOUT	
JOB NAME: BOX CAR CAMPGROUND	
DATE: MARCH 6, 2017	
JOB NO: 1112004	DESIGN BY: MEK
PAGE: 2 OF 3	DRAWN BY: MEK



Stuntzner Engineering & Forestry, LLC	Stuntzner Engineering & Forestry, LLC ENGINEERING * LAND SURVEYING * FORESTRY LAND PLANNING * WATER RIGHTS	705 SOUTH 4TH STREET P.O. BOX 118 COOS BAY, OREGON 97420	Sanitary Waste System JOB NAME: BOX CAR CAMPGROUND DATE: March 8, 2017
		PHONE: (541) 267-2872 FAX: (541) 267-0588 www.stuntzner.com	JOB NO: 1112004 · DESIGN BY: RED PAGE: 3 OF 3 · DRAWN BY: MEK

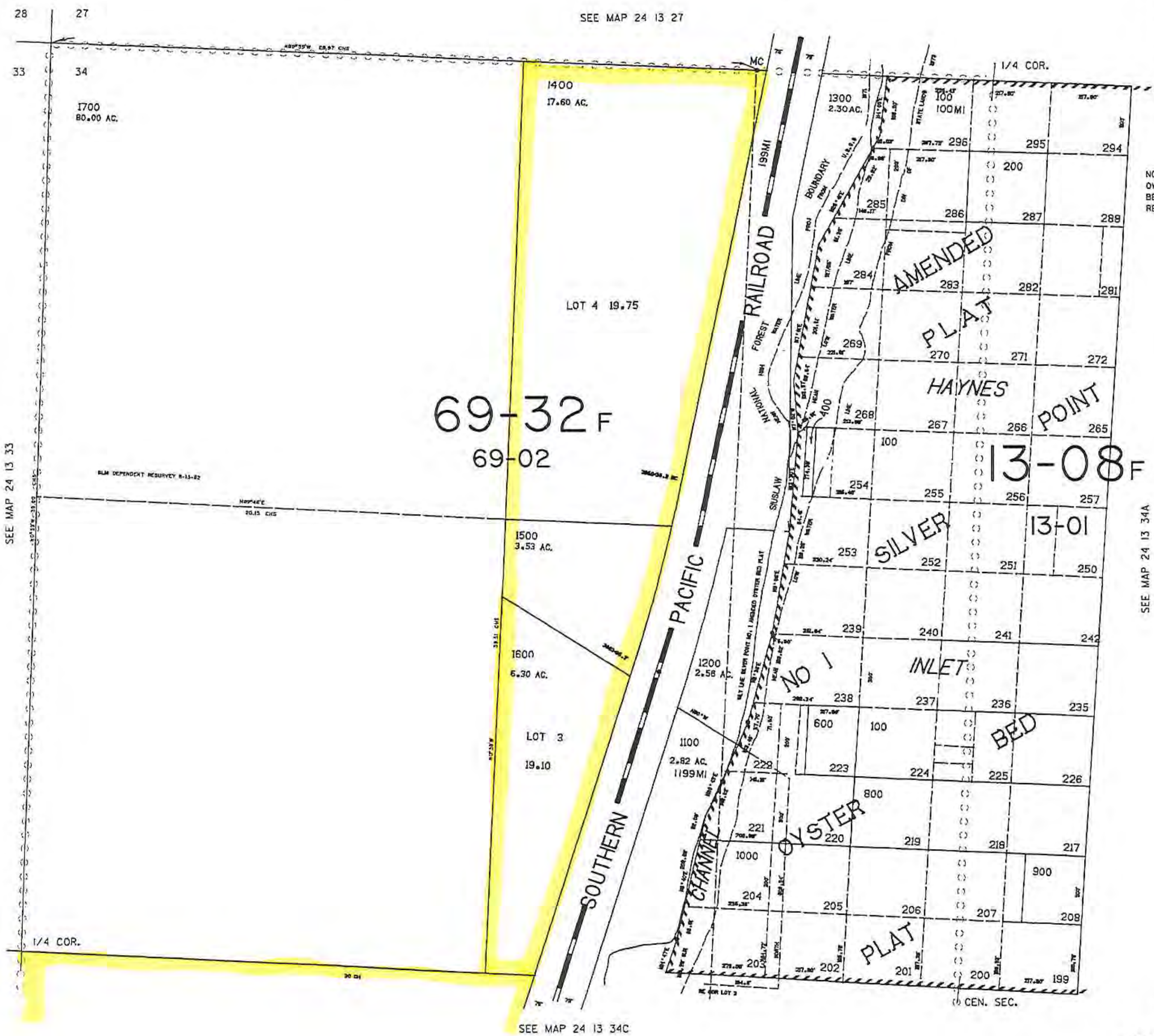
THIS MAP WAS PREPARED FOR ASSESSMENT PURPOSE ONLY

NW1/4 SEC. 34 T.24S. R.13W. W.M.
COOS COUNTY

1" = 200'

24 13 34B

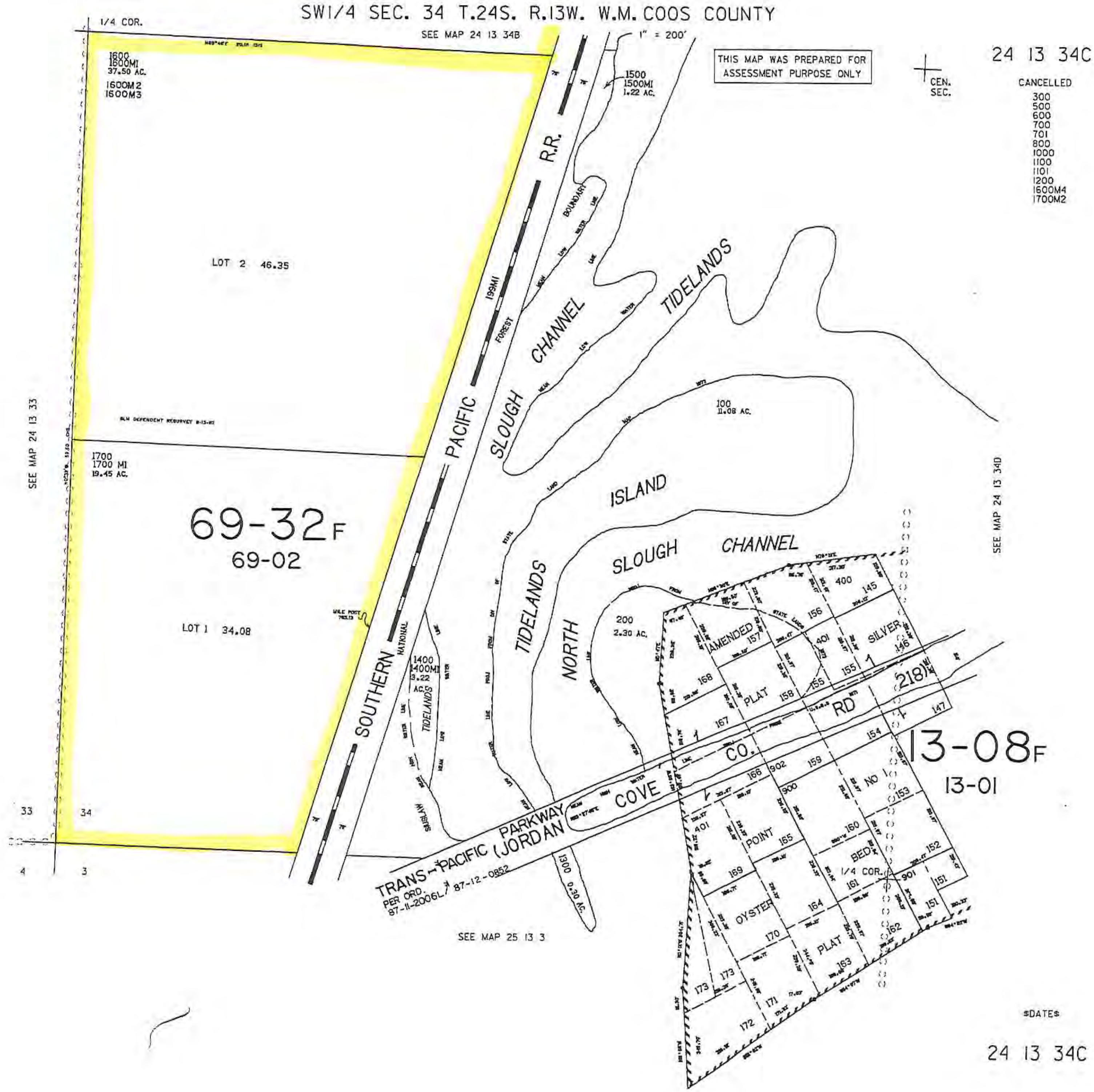
CANCELLED
300
500
700
1100MI
1200MI
1300MI
1400MI
1500MI
1600MI



NOTE:
OWNERSHIP TO OYSTER BEDS FROM TITLE CO RECORDS 10/77

$DATE$

24 13 34B



SW1/4 SEC. 34 T.24S. R.13W. W.M. COOS COUNTY
SEE MAP 24 13 34B
1" = 200'
THIS MAP WAS PREPARED FOR ASSESSMENT PURPOSE ONLY
CEN. SEC.
24 13 34C
CANCELLED
300
500
600
700
701
800
1000
1100
1101
1200
1600M4
1700M2
1/4 COR.
1600
1600MI
37.50 AC.
1600M2
1600M3
1500
1500MI
1.22 AC.
LOT 2 46.35
SEE MAP 24 13 33
1700
1700 MI
19.45 AC.
69-32F
69-02
LOT 1 34.08
SOUTHERN PACIFIC R.R.
NATIONAL
FOREST
199MI
BOUNDARY
SLOUGH CHANNEL
TIDELANDS
100
11.08 AC.
ISLAND
NORTH SLOUGH CHANNEL
TIDELANDS
SIUSLAW
1400
1400MI
3.22 AC.
TIDELANDS
200
2.30 AC.
1300 0.30 AC.
TRANS-PACIFIC PARKWAY (JORDAN COVE CO. RD 218)
PER ORD. 87-11-2006L, 87-12-0852
AMENDED PLAT
SILVER
NO
BED
1/4 COR.
OYSTER POINT PLAT
400
145
156
157
401
146
155
168
158
167
154
147
166
902
159
900
153
401
165
160
169
152
161
901
151
164
170
162
173
163
171
172
13-08F
13-01
33
34
4
3
SEE MAP 25 13 3
SEE MAP 24 13 34D
$DATE$
24 13 34C

Richard L. Goergen, Richard T. Goergen and Mathew G. Goergen
PO Box 97
Coos Bay, OR 97420
Grantor's Name and Address
Oregon Dunes Sand Park, LLC
PO Box 97
Coos Bay, OR 97420
Grantee's Name and Address

After recording return to:
Anthony J. Motschenbacher
117 SW Taylor Street, Suite 200
Portland, OR 97204-3029

Until requested otherwise send all tax statements to:
Oregon Dunes Sand Park, LLC
PO Box 97
Coos Bay, OR 97420

Space Reserved For Recorder's Use

COOS COUNTY CLERK, OREGON
TERRI L. TURI, CCC, COUNTY CLERK
TOTAL $46.00

05/16/2011 11:07:05AM
PAGE 1 OF 2

2011 3747

STATUTORY WARRANTY DEED

KNOW ALL MEN BY THESE PRESENTS, that Richard L. Goergen, Richard T. Goergen and Mathew G. Goergen, each as to an undivided 1/3 (one-third) interest, Grantor, convey and warrant to Oregon Dunes Sand Park, LLC, Grantee, the real property located in Coos County, State of Oregon, and described on Exhibit A attached hereto, free of all encumbrances except those encumbrances of record.

Grantor hereby covenants to and with Grantee and Grantee's heirs, successors and assigns, that Grantor is lawfully seized in fee simple of the above granted premises, free from all encumbrances, except those encumbrances of record. Grantor will warrant and forever defend the premises and every part and parcel thereof against the lawful claims and demands of all persons whomsoever, except those claiming under the above described encumbrances.

The true and actual consideration paid for this transfer, stated in terms of dollars, is $other than dollars.

In Witness Whereof, the Grantor has executed this instrument this 3 day of May 2011; if a corporate grantor, it has caused its name to be signed and its seal, if any, affixed by an officer or other person duly authorized to do so by order of its board of directors.

BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON TRANSFERRING FEE TITLE SHOULD INQUIRE ABOUT THE PERSON'S RIGHTS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, AND SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009. THIS INSTRUMENT DOES NOT ALLOW USE OF THE PROPERTY DESCRIBED IN THIS INSTRUMENT IN VIOLATION OF APPLICABLE LAND USE LAWS AND REGULATIONS. BEFORE SIGNING OR ACCEPTING THIS INSTRUMENT, THE PERSON ACQUIRING FEE TITLE TO THE PROPERTY SHOULD CHECK WITH THE APPROPRIATE CITY OR COUNTY PLANNING DEPARTMENT TO VERIFY THAT THE UNIT OF LAND BEING TRANSFERRED IS A LAWFULLY ESTABLISHED LOT OR PARCEL, AS DEFINED IN ORS 92.010 OR 215.010, TO VERIFY THE APPROVED USES OF THE LOT OR PARCEL, TO DETERMINE ANY LIMITS ON LAWSUITS AGAINST FARMING OR FOREST PRACTICES AS DEFINED IN ORS 30.930 AND TO INQUIRE ABOUT THE RIGHTS OF NEIGHBORING PROPERTY OWNERS, IF ANY, UNDER ORS 195.300, 195.301 AND 195.305 TO 195.336 AND SECTIONS 5 TO 11, CHAPTER 424, OREGON LAWS 2007, AND SECTIONS 2 TO 9 AND 17, CHAPTER 855, OREGON LAWS 2009.

Richard L. Goergen

Richard T. Goergen

Mathew G. Goergen

STATE OF OREGON) ss. County of Coos)

This instrument was acknowledged before me on May 3, 2011 by Richard L. Goergen, Richard T. Goergen and Mathew G. Goergen.

Rosanne D Wales
Notary Public for Oregon
My commission expires: 3/20/14

OFFICIAL SEAL
ROSANNE D WALES
NOTARY PUBLIC-OREGON
COMMISSION NO. 446902
MY COMMISSION EXPIRES MARCH 20, 2014

H:\Tony\OREDUN.2101\LLC.001\Corporate Documents\Warranty Deed.doc

EXHIBIT A
Legal Description

PARCEL 1: That portion of Government Lot 3, Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon, lying North of the following described line and West of the Westerly right of way line of the Southern Pacific Company railroad right of way: Beginning 9.14 chains (603.24 feet) North and 2.8 chains (184.8 feet) East of the Southeast corner of said Government Lot 3; thence North 60° West to the West line of said Government Lot 3.

PARCEL 2: That portion of Government Lot 1 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon, lying Westerly of the right of way line of the Southern Pacific Company railroad right of way.

PARCEL 3: Government Lot 3 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon.

SAVING AND EXCEPTING THEREFROM: A parcel deeded to N. G. Ostrom, recorded in Book 28, Page 52, Deed Records of Coos County, Oregon, described as follows: Beginning 9 chains and 14 links North and 2 chains and 80 links East of the Southeast corner of Government Lot 3 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon; thence North 60° 00' West to the West line of said Government Lot 3; thence North to the Northwest corner of said Government Lot 3; thence East to the high water line of Coos Bay;
thence Southerly along the high water line to a point due East of the point of beginning; thence West to the point of beginning.

SAVING AND EXCEPTING THEREFROM: Any portion of Government Lot 3 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon, lying within the Southern Pacific Company railroad right of way.

PARCEL 5: Government Lot 4 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon.

SAVING AND EXCEPTING THEREFROM: Any portion of Government Lot 4 of Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon, lying within the Southern Pacific Company railroad right of way.

After Recording, return to:
Anthony J. Motschenbacher
117 S.W. Taylor Street, Suite 200
Portland, OR 97204

COPY

Grantor's Name and Address:
Oregon Dunes Sand Park, LLC
PO Box 97
Coos Bay, OR 97420

Beneficiary's Name and Address:
Cedar Valley, Inc.
PO Box 1210
North Bend, OR 97459

Deed of Trust

THIS DEED OF TRUST, made this 4th day of December, 2014, between Oregon Dunes Sand Park, LLC ("Grantor"), and Anthony J. Motschenbacher, ("Trustee"), whose address is 117 SW Taylor Street, Suite 200, Portland, Oregon, and Cedar Valley, Inc. ("Beneficiary") whose address is PO Box 1210, North Bend, Oregon 97459.

WITNESSETH: Grantor hereby bargains, sells and conveys to Trustee in Trust, with power of sale, the real property in Coos County, Oregon, described as follows:

> All that part of Government Lot 2 in Section 34, Township 24 South, Range 13 West of the Willamette Meridian, Coos County, Oregon, lying Westerly of the Westerly line of the South Pacific Railroad right-of-way

("Property") which real property is not used principally for agricultural or farming purposes, together with all the tenements, hereditament, and appurtenances now or hereafter thereunto belonging or in any wise appertaining, and the rents, issues and profits thereof.

This Deed of Trust is for the purpose of securing performance of each agreement of Grantor herein contained, and the payment by Grantor of all amounts due in satisfaction of each obligation of Grantor in its Promissory Note in the principal amount of $206,250, payable to Beneficiary. The date of maturity of the Promissory Note is due on Demand.

TO PROTECT THE SECURITY OF THIS DEED OF TRUST, GRANTOR COVENANTS AND AGREES:

1. To keep the property in good condition and repair; permit no waste thereof; to complete any building, structure or improvement being built or about to be built thereon; to restore promptly any building, structure or improvement thereon which may be damaged or destroyed; and to comply with all law, ordinances, regulations, covenants, conditions and restrictions affecting the Property.

2. To pay before delinquent all lawful taxes and assessments upon the Property; to keep the Property free and clear of all other charges, liens or encumbrances impairing the security of this Deed of Trust.

3. To keep all buildings now or hereafter erected on the Property described herein continuously insured against loss by fire or other hazards in an amount not less than the total debt secured by this Deed of Trust. All policies shall be held by the Beneficiary, and be in such companies as the Beneficiary may approve and have loss payable first to the Beneficiary as its interest may appear and then to the Grantor. The amount collected under any insurance policy may be applied upon any indebtedness hereby secured in such order as the Beneficiary shall determine. Such application by the Beneficiary shall not cause discontinuance of any proceedings to foreclose this Deed of Trust. In the event of foreclosure, all rights of the Grantor in insurance policies then in force shall pass to the purchaser at the foreclosure sale.

4. To defend any action or proceeding purporting to affect the security hereof or the rights or powers of Beneficiary or Trustee, and to pay all costs and expenses, including cost of title search and attorney's fees actually incurred, as provided by statute.

5. Should Grantor fail to pay when due any taxes, assessments, insurance premiums, liens, encumbrances or other charges against the Property hereinabove described, Beneficiary may pay the same, and the amount so paid, with interest at the rate set forth in the note secured hereby, shall be added to and become a part of the debt secured in this Deed of Trust.

IT IS MUTUALLY AGREED THAT:

1. In the event any portion of the Property is taken or damaged in an eminent domain proceeding, the entire amount of the award or such portion thereof as may be necessary to fully satisfy the obligation secured hereby, shall be paid to Beneficiary to be applied to said obligation.

2. By accepting payment of any sum secured hereby after its due date, Beneficiary does not waive its right to require prompt payment when due of all other sums so secured or to declare default or failure to so pay.

3. The Trustee shall reconvey all or any part of the Property covered by this Deed of Trust to the person entitled thereto, on written request of the Grantor and the Beneficiary, or upon satisfaction of the obligation secured and written request for reconveyance made by the Beneficiary or the person entitled thereto.

4. Upon any default by Grantor hereunder, Beneficiary may, at any time without notice, either in person, by agent, or by a receiver to be appointed by a court, and without regard to the adequacy of any security for the indebtedness hereby secured, enter upon and take possession of the property or any part thereof, in its own name, sue or otherwise collect the rents, issues and profits, including those past due and unpaid, and apply the same, less costs and expenses of operation and collection, including reasonable attorney fees, upon any indebtedness secured hereby, and in such order as Beneficiary may determine.

5. Upon default by Grantor in payment of any indebtedness secured hereby or in Grantor's performance of any agreement hereunder, time being of the essence with respect to such payment and/or performance, the Beneficiary may declare all sums secured hereby immediately due and payable. In such event, the Beneficiary may elect to proceed to foreclose this trust deed in equity as a mortgage or direct the Trustee to foreclose this trust deed by advertisement and sale, or may direct the Trustee to pursue any other right or remedy, either at law or in equity, which the beneficiary may have. In the event the Beneficiary elects to foreclose by advertisement and sale, the Beneficiary or the Trustee shall execute and cause to be recorded a written notice of default and election to sell the property to satisfy the obligations secured hereby whereupon the Trustee shall fix the time and place of sale, give notice thereof as then required by law and proceed to foreclose this trust deed in the manner provided in ORS 86.735 to 86.795.

6. After the Trustee has commenced foreclosure by advertisement and sale, and at any time prior to five (5) days before the date the Trustee conducts the sale, the Grantor or any other person so privileged by ORS 86.753 may cure the default or defaults. If the default consists of a failure to pay, when due, sums secured by the trust deed, the default may be cured by paying the entire amount due at the time of the cure other than such portion as would not then be due had no default occurred. Any other default that is capable of being cured may be cured by tendering the performance required under the obligation or trust deed. In any case, in addition to curing the default or defaults, the person effecting the cure shall pay to the Beneficiary all costs and expenses actually incurred in enforcing the obligation of the trust deed, together with Trustee and attorney fees not exceeding the amounts provided by law.

7. Otherwise, the sale shall be held on the date and at the time and place designated in the notice of sale or the time to which the sale may be postponed as provided by law. The Trustee may sell the property either in one parcel or in separate parcels and shall sell the parcel or parcels at auction to the highest bidder for cash, payable at the time of sale. Trustee shall deliver to the purchaser its deed in form as required by law conveying the property so sold, but without any covenant or warranty, express or implied. The recitals in the deed of any matters of fact shall be conclusive proof of the truthfulness thereof. Any person, excluding the Trustee, but including the Grantor and Beneficiary, may purchase at the sale.

8. When Trustee sells pursuant to the powers provided herein, Trustee shall apply the proceeds of sale to payment of: (1) the expenses of sale, including the compensation of the Trustee and a reasonable charge by Trustee's attorney; (2) to the obligation secured by the trust deed; (3) to all persons having recorded liens subsequent to the interest of the Trustee in the trust deed as their interests may appear in the order of their priority; and (4) the surplus, if any, to the Grantor, or to any successor in interest entitled to such surplus.

9. In the event of the death, incapacity, disability or resignation of Trustee, Beneficiary may appoint in writing a successor Trustee, and upon the recording of such appointment in the mortgage records of the county in which this Deed of Trust is recorded, the successor Trustee shall be vested with all powers of the original trustee. The Trustee in not obligated to notify any party hereto of pending sale under any other Deed of Trust or of any action preceding which Grantor, Trustee or Beneficiary shall be a party unless such action or proceeding is brought by the Trustee.

10. This Deed of Trust applies to, inures to the benefit of, and is binding not only on the parties hereto, but on their heirs, devisees, legatees, administrators, executors, successors and assigns. The term Beneficiary shall mean the holder and owner of the note secured hereby, whether or not named as Beneficiary herein.

11. This Deed of Trust shall be payable in full in the event of any sale or other transfers of premises by Grantor.

WARNING: Unless Grantor provides Beneficiary with evidence of insurance coverage as required by the contract or loan agreement between them, Beneficiary may purchase insurance at Grantor's expense to protect Beneficiary's interest. This insurance may, but need not, also protect Grantor's interest. If the collateral becomes damaged, the coverage purchased by Beneficiary may not pay any claim made by or against Grantor. Grantor may later cancel the coverage by providing evidence that Grantor has obtained property coverage elsewhere. Grantor is responsible for the cost of any insurance coverage purchased by Beneficiary, which cost may be added to Grantor's contract or loan balance. If it so added, the interest rate on the underlying contract or loan will apply to it. The effective date of coverage may be the date Grantor's prior coverage lapsed or the date Grantor failed to provide proof of coverage. The coverage Beneficiary purchases may be considerably more expensive than insurance Grantor might otherwise obtain alone and may not satisfy any need for property damage coverage or any mandatory liability insurance requirements imposed by applicable law.

The Grantor warrants that the proceeds of the loan represented by the above-described note and this trust deed are for an organization, or (even if Grantor is a natural person) are for business or commercial purposes.

This deed applies to, inures to the benefit of, and binds all parties hereto, their heirs, legatees, devisees, administrators, executors, personal representatives, successors and assigns. The term Beneficiary shall mean the holder and owner, including pledgee, of the contract secured hereby, whether or not named as a beneficiary herein.

In construing this trust deed, it is understood that the Grantor, Trustee and/or Beneficiary may each be more than one person; that if the context so requires, the singular shall be taken to mean and include the plural, and that generally all grammatical changes shall be made, assumed and implied to make the provisions hereof apply equally to corporations and to individuals.

IN WITNESS WHEREOF, the Grantor has executed this instrument the day and year first written above.

OREGON DUNES SAND PARK, LLC

By: ______________________

R. Todd Goergen, Manager

STATE OF OREGON)
) ss.
COUNTY OF COOS)

On this day personally appeared before me R. TODD GOERGEN, AS MANAGER OF OREGON DUNES SAND PARK, LLC, to me known to be the individual described in and who executed the within and foregoing instrument, and acknowledged that he signed the same as his free and voluntary act and deed, for the uses and purposes therein mentioned.

GIVEN under my hand and official seal this 4th day of December, 2014.

NOTARY PUBLIC in and for the State of Oregon
Commission Expires: 9-29-18

OFFICIAL STAMP
DENISE ALTHEA MATESKI
NOTARY PUBLIC-OREGON
COMMISSION NO. 932623
MY COMMISSION EXPIRES SEPTEMBER 29, 2018

Exhibit 22

NOTICE OF LAND USE DECISION BY THE COOS COUNTY PLANNING DIRECTOR

Coos County Planning
225 N. Adams St.
Coquille, OR 97423
http://www.co.coos.or.us/
Phone: 541-396-7770
Fax: 541-396-1022

Date of this Decision:	April 21, 2017
File Number:	ACU-17-009
Applicant:	Oregon Dunes Sand Park, LLC
Account Number:	185603, 185601, 185604, 185607,
Map Number:	Township 24S Range 13 Sections 34B/34C Tax Lots 1400, 1500, 1600/1600, 1700
Property Owner:	OREGON DUNES SAND PARK, LLC PO BOX 97 COOS BAY, OR 97420-0010
Situs Address:	92799 Transpacific Parkway
Acreage:	84.38 total acres
Zoning:	INDUSTRIAL (IND)
Special Considerations:	AIRPORT - NORTH BEND - CONICAL SURFACE (NBCS) COASTAL SHORELAND BOUNDARY (CSB) FLOODPLAIN (FP) NATIONAL WETLAND INVENTORY SITE (NWI)
Proposal:	Request for Planning Director Approval for an alternation of a non-conforming use within the Industrial Zone as provided by Coos County Zoning and Land Development Ordinance (CCZLDO) § 5.6.120 Alterations, Repairs or Verification and § 5.6.125 Criteria For Decisions.
Decision:	This request meets the criteria subject to conditions of approval found at Exhibit A. Approval is based on findings and facts represented in the staff report.

This notice is to serve as public notice and decision notice and if you have received this notice by mail it is because you are a participant, adjacent property owner, special district, agency with interest, or person with interest in regard to the following land use application. Please read all information carefully as this decision may affect you. (See attached vicinity map for the location of the subject property).

Notice to mortgagee, lien holder, vendor or seller: ORS Chapter 215 requires that if you receive this notice, it must be forwarded to the purchaser.

The purpose of this notice is to inform you about the proposal and decision, where you may receive more information, and the requirements if you wish to appeal the decision by the Director to the Coos County Hearings Body. Any person who is adversely affected or aggrieved or who is entitled to written notice may appeal the decision by filing a written appeal in the manner and within the time period as provided below pursuant to Coos County Zoning and Land Development Ordinance (CCZLDO) Article 5.8. If you are mailing any documents to the Coos County Planning Department the address is 250 N. Baxter, Coquille OR 97423. Mailing of this notice to you precludes an appeal directly to the Land Use Board of Appeals.

The application, staff report and any conditions can be found at the following link: http://www.co.coos.or.us/Departments/Planning/PlanningDepartment-Applications2016.aspx . The application and all documents and evidence contained in the record, including the staff report and the applicable criteria, are available for inspection, at no cost, in the Planning Department located at 225 North Adams Street, Coquille, Oregon. Copies may be purchased at a cost of 50 cents per page. The decision is based on the application submittal and information on record. The name of the Coos County Planning Department representative to contact Jill Rolfe, Planning Director and the telephone number where more information can be obtained is **(541) 396-7770**.

This decision will become final at 12 P.M. on May 8, 2017 unless before this time a completed **APPLICATION FOR AN APPEAL OF A DECISION BY THE PLANNING DIRECTOR** form is submitted to and received by the Coos County Planning Department.

Failure of an issue to be raised in a hearing, in person or in writing, or failure to provide statements of evidence sufficient to afford the Approval Authority an opportunity to respond to the issue precludes raising the issue in an appeal to the Land Use Board of Appeals.

Reviewed by: Crystal Orr **Date:** April 21, 2017
Crystal Orr, Planning Specialist

Authorized by: Jill Rolfe **Date:** April 21, 2017
Jill Rolfe, Planning Director

EXHIBITS

Exhibit A: Conditions of Approval
Exhibit B: Vicinity Map

The Exhibits below are mailed to the Applicant only. Copies are available upon request or at the following website: http://www.co.coos.or.us/Departments/Planning/PlanningDepartment-Applications2016.aspx or by visiting the Planning Department at 225 N. Baxter, Coquille OR 97423. If you have any questions please contact staff at (541) 396-7770.

Exhibit C: Staff Report
Exhibit D: Comments received (There were no comments received on this application)

EXHIBIT "A"
CONDITIONS OF APPROVAL

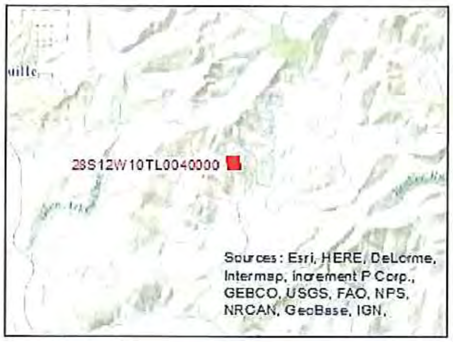
1. Alteration of the non-conforming commercial use within the industrial zone may be permitted subject to Sections 5.6.120 and 5.6.125 of the CCZLDO. Alteration of this use shall be permitted when necessary to comply with any lawful requirement for alteration in the use.

2. Conditions are only allowed to be placed on non-conforming use when necessary to comply with state or local health or safety requirements, or to maintain in good repair the existing structures associated with the use. A change of ownership or occupancy shall be permitted.

EXHIBIT "B"
Vicinity Map

COOS COUNTY PLANNING DEPARTMENT

Mailing Address: 250 N. Baxter, Coos County Courthouse, Coquille, Oregon 97423
Physical Address: 225 N. Adams, Coquille Oregon
Phone: (541) 396-7770
Fax: (541) 396-1022/TDD (800) 735-2900



File:	HBCU-16-013
Applicant/ Owner:	R & M Quarries, LLC / Peter Billeter
Date:	July 13, 2016
Location:	Township 28S Range 12W Section 10 TL 400
Proposal:	Hearings Body Conditional Use

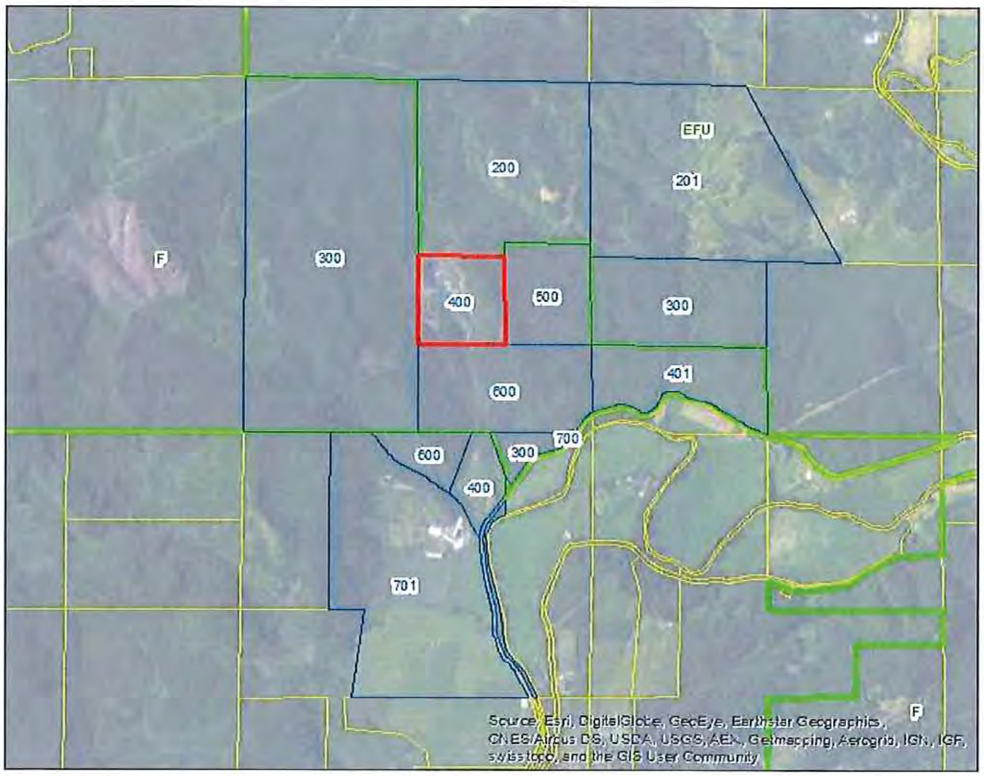


EXHIBIT "C"
Staff Report

File Number:	ACU-17-009
Applicant:	Oregon Dunes Sand Park, LLC
Account Number	185603, 185601, 185604, 185607,
Map Number	Township 24S Range 13 Sections 34B/34C Tax Lots 1400, 1500, 1600/1600, 1700
Property Owner	OREGON DUNES SAND PARK, LLC PO BOX 97 COOS BAY, OR 97420-0010
Situs Address	92799 Transpacific Parkway
Acreage	84.38 total acres
Zoning	INDUSTRIAL (IND)
Special Considerations	AIRPORT - NORTH BEND - CONICAL SURFACE (NBCS) COASTAL SHORELAND BOUNDARY (CSB) FLOODPLAIN (FP) NATIONAL WETLAND INVENTORY SITE (NWI)

Reviewing Staff: Crystal Orr
Date of Report: April 21, 2017

I. PROPOSAL:

Request for Planning Director Approval for an alternation of a non-conforming use within the Industrial Zone as provided by Coos County Zoning and Land Development Ordinance (CCZLDO) § 5.6.120 Alterations, Repairs or Verification and § 5.6.125 Criteria For Decisions. The applicant has requested approval to expand an existing Recreational Vehicle park.

II. BACKGROUND INFORMATION

- Township 24S Range 13 Section 34B Tax Lot 1400: No development has occurred on this tax lot.
- Township 24S Range 13 Section 34B Tax Lot 1500: No development has occurred on this tax lot.
- Township 24S Range 13 Section 34B Tax Lot 1600: No development has occurred on this tax lot.
- Towuship 24S Range 13 Section 34C Tax Lot 1600: No development has occurred on this tax lot.
- Township 24S Range 13 Section 34C Tax Lot 1700: This tax lot currently has a high intensity RV park, a host dwelling, and a sand park permitted in 2006.

III. PROPERTY DESCRIPTION AND PROPOSAL

LAWFULLY CREATED: This property is lawfully created pursuant to § 6.1.125.8. The 1968 entry in the assessment records shows deeds described the property as it is currently configured.

LOCATION: The subject property is located north of the city of North Bend on Trans Pacific Parkway.

SITE DESCRIPTION AND SURROUNDING USES:

a. **SITE DESCRIPTION AND SURROUNDING USES:** The subject property contains a RV/ campground and sand park that has been in existence since 2006. The property is mostly sand dunes with a small amount of trees on the eastern side and an asphalt parking lot on the south end of the property. The properties surrounding this property appear to be used for dune access or recreational camping.

b. **PROPOSAL:** The applicant requests to expand the RV campground which is an expansion or alteration of a non-conforming use.

IV. APPROVAL CRITERIA & FINDINGS OF FACT

- ***SECTION 5.6.120 ALTERATIONS, REPAIRS OR VERIFICATION:***

Alterations, repairs or verification of a nonconforming use requires filing an application for a conditional use (See CCZLDO Article 5.2). All such applications shall be subject to the provisions of Section 5.6.125 of this ordinance and consistent with the intent of ORS 215.130(5)-(8). Alteration of any nonconforming use shall be permitted when necessary to comply with any lawful requirement for alteration in the use. The County shall not condition an approval of a land use application when the alteration is necessary to comply with State or local health or safety requirements, or to maintain in good repair the existing structures associated with the use.

Finding: In 2006 an application was approved for a sand park including an RV Park under the listed use of High Intensity Recreation. Since that time revisions have been done to the Coos County Zoning and Land Development Ordinance that changed the uses making the current use a nonconforming use. The proposal is to expand the use which required the applicant to file a conditional use application.

- ***SECTION 5.6.125 CRITERIA FOR DECISION:***

When evaluating a conditional use application for alteration or repair of a nonconforming use, the following criteria shall apply:

1. *The change in the use will be of no greater adverse impact to the neighborhood;*

2. *The change in a structure or physical improvements will cause no greater adverse impact to the neighborhood; and*

3. *Other provisions of this ordinance, such as property development standards, are met.*

For the purpose of verifying a nonconforming use, an applicant shall provide evidence establishing the existence, continuity, nature and extent of the nonconforming use for the 10-year period immediately preceding the date of the application, and that the nonconforming use was lawful at the time the zoning ordinance or regulation went into effect. Such evidence shall create a rebuttable presumption that the nonconforming use lawfully existed at the time the applicable zoning ordinance or regulation was adopted and has continued uninterrupted until the date of the application.

Finding: The property is located in a mixed zoned area with Recreational to the west, northwest and east of the property and Industrial to the northeast and south. The IND zoned properties to the south are buffered by a road named Transpacific Parkway. The property to the west is in federal ownership and is used for recreational purposes. The property consists mostly of sand dunes and the surrounding properties are mainly sand dunes; therefore, this expansion will not be of any greater adverse impact to the neighbor. The proposal is to include an addition to the RV Park and expansion of recreational activities supported by the sand dunes. The park expansion seems justified given the growth of this use on and adjacent to this property.

The applicant provided a plot plan of the expansion area and it meets the property development standards. The plans are consistent with the original approval and phased planning.

Therefore, this expansion application meets the criteria.

VI. DECISION:

There is evidence to adequately address the criteria for an expansion of a non-conforming use (RV Park expansion and expansion of recreational activities supported by the sand dunes); therefore, this request has been approved. There are conditions that apply to this use that can be found at Exhibit "A".

VII. EXPIRATION AND EXTENSION OF CONDITIONAL USES

This is a non-conforming use the conditional use remains valid unless the use has been discontinued for more than one (1) year. If the use has been discontinued for more than one (1) year this use will be considered abandoned and the property owner will be required to comply with the current regulations of the Coos County Zoning and Land Development Ordinance.

Exhibit 23

Jordan Cove Energy Project, L.P.

Pacific Connector GAS PIPELINE

December 4, 2018

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Pacific Connector Gas Pipeline, LP* and *Jordan Cove Energy Project L.P.*
Docket Nos. CP17-494-000 and CP17-495-000
Request to Update Service Lists

Dear Ms. Bose:

Pursuant to Rule 2010 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, 18 C.F.R. § 385.2010 (2018), Jordan Cove Energy Project L.P. ("JCEP") and Pacific Connector Gas Pipeline, LP ("PCGP") respectfully request that the Commission update the official service lists in the captioned dockets as shown below.

Please **add** the following individuals to the service lists:

Natalie Eades
Manager, Environment
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: 832-255-3841
Email: NEades@pembina.com

Michael Koski
Senior Manager, External Affairs
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: 971-940-7800
Email: MKoski@pembina.com

Please **remove** the following individuals from the service lists:

Elizabeth Spomer
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: espomer@vereseninc.com

Rose Haddon
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: rose.haddon@jordancovelng.com

JCEP and PCGP respectfully request that the Commission waive Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), in order to allow all designated representatives to be included on the Commission's official service lists. In addition to changing the service list, please direct future correspondence to me at the address written above. Should you have any questions, please contact me at neades@pembina.com or 832-255-3841.

Sincerely,

/s/ Natalie Eades
Natalie Eades
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP

CERTIFICATE OF SERVICE

I hereby certify that I have this 4th day of December, 2018, served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

/s/ Victoria R. Galvez
Victoria R. Galvez
Attorney for
Jordan Cove Energy Project L.P.
Pacific Connector Pipeline, LP

Exhibit 24

The Following from – http://timrileylaw.com/LNG.htm
January 19, 2004
LNG BLAST

LNG Explosion In Algeria Industrial Zone

Port was designed to load only small LNG Tankers for short distances
Death Toll Currently: 27
Workers Injured: 74
Blast Felt Miles Away
Facility Destroyed
Fires Raged For 8 Hours
Property Damage: Approx. $ 1 Billion
Cause: Initially: "Defective Boiler" Which Had Earlier Received "Superficial Repairs"
Cause: Currently: Liquefied Natural Gas Leak in Pipe

SEE NEWS STORY EXCERPTS ABOUT THE ACCIDENT FURTHER BELOW

BBC NEWS

Four killed in Algeria gas blast

Monday, 19 January, 2004, 21:35 GMT
Full Story: http://news.bbc.co.uk/1/hi/world/africa/3411651.stm
ABSTRACTS:

An explosion at a natural gas complex in Algeria has killed at least four people and injured about 60 others. The blast took place at a state-owned liquefied natural gas unit in the industrial zone of the north-eastern coastal town of Skikda.

"We're still fighting the fires but we have yet to determine the cause of the explosion," a civil defense official in Skikda told Reuters news agency.

One witness told Reuters the explosion was felt miles away.

Reuters

At least 27 dead in Algeria blast, refinery shut

January 20, 2004
By Zohra Bensemra
Full Story:
http://www.reuters.com/locales/newsArticle.jsp;:400d65e8:2f1f10da5ee06141?type=worldNews&locale=en_IN&storyID=4165226

SKIKDA, Algeria (Reuters) - At least 27 workers died when a gas plant blew up...
The powerful blast and consequent fires devastated...
It was the worst LNG accident since 1975 when about 40 people died in an explosion in Staten Island, U.S., according to Andrew Flower, an independent gas consultant...

Channelnewsasia.com

Algerian gas plant explosion kills 27, injures 72

21 January 2004 0044 hrs (SST)
Full Story: http://www.channelnewsasia.com/stories/afp_world/view/67231/1/.html

ALGIERS : At least 27 people were killed and 72 injured when a huge explosion, apparently caused by a defective boiler, ripped through a liquefied natural gas plant ...

He said specialists had filed a report "more than a year ago" indicating that the boiler in question was defective. "Superficial repairs" had been carried out on the boiler, he said.

A woman living close to the plant, about 10 kilometres (six miles) outside Skikda, said: "There was a heavy blast and everything started to shake and the windows of my apartment were blown out."

Speaking haltingly, she said the complex was engulfed in smoke and flames. "We all ran out, we helped the handicapped and the old people," she said, adding: "Many of them were in shock and the children were crying."

... fire at the plant had been brought under control early Tuesday after raging for almost eight hours. (*Emphasis added*)

1/21/04
MOBILE REGISTER

More bodies found at LNG blast scene

At least 27 dead at facility similar to terminals proposed for Mobile Bay
Full Story: http://www.al.com/news/mobileregister/index.ssf?/base/news/1074680100132040.xml

Searchers discovered 10 more bodies at a liquefied natural gas complex in Algeria leveled by an explosion, raising the death toll to at least 27... Seventy-four people were injured... dozen workers were believed missing...

Information available from the Halliburton Co. of Texas shows that the oil construction giant had in recent years revamped the Algerian facility to the latest performance standards...

Industry officials and some government officials have said that such facilities have a spotless safety record, could not explode, and would pose little risk to surrounding communities. But in recent months, the Mobile Register has reported that government officials have sometimes used faulty studies to make their case to the public...

LNG industry officials maintained that the accident in Algeria should not affect how the public perceives LNG terminals in the United States.

"I would not make a direct link between the accident and any U.S. site, Mobile included," said ExxonMobil spokesman Bob Davis in Houston. "As tragic as the Algerian accident is, I don't think it negates the outstanding 40-year safety record of LNG in the world."

Davis said that the Algerian facility is "one of the oldest LNG facilities in the world, vintage 1970s. I think certainly from our point of view, the technology on these facilities has advanced substantially in that 30-year period."

But a Halliburton Co. Web site states that its engineering branch, KBR, updated the entire Skikda terminal as recently as 1999. The Web site touts the project as a model of modern American workmanship.

"Halliburton Company is pleased to announce that its recently completed Liquefied Natural Gas Revamp Project at Skikda, Algeria, has passed all its performance tests," reads the **company press release announcing the project's completion. "KBR's work included extensive revamp of the three LNG trains and associated utilities and auxiliaries and a complete revamp of the complex's electrical power and control systems. ... Over 9,000,000 construction man-hours were expended. "**

Lyons said the reports he read Tuesday claim a high-pressure boiler in need of maintenance was the cause of the accident.

"They wouldn't have high-pressure boilers at an LNG receiving terminal. I don't see any parallel in any respect to what is being contemplated anywhere along the Gulf Coast as far as LNG receiving terminals," Lyons said.

Register research, however, indicates that most existing LNG receiving terminals employ numerous boilers, many of them generating high pressure. For instance, a newly proposed LNG terminal in Freeport, Texas, would use six high-pressure vaporizers connected to 12 boilers, according to documents posted on a U.S. Environmental Protection Agency Web site.

Most LNG tankers are also powered by steam turbine engines that require large high-pressure boilers. Scientists say that an accident or terrorist attack involving a tanker could produce a fire that is much larger than an LNG fire on land... (*Emphasis added*)

(Mobile Register Staff Reporters Bill Finch, Ben Raines and Lee Davidson contributed to this article.)

UpstreamOnline.com
February 3, 2004

Industry opponents have a field day

Full Story: http://www.upstreamonline.com/news/article.jsp?Id=EPS_52937
By Dann Rodgers

Opponents of LNG import projects in the US have wasted no time in pointing to last week's tragedy in Algeria as highlighting safety concerns about such facilities

"The Algerian explosion destroyed more than an LNG facility -- it destroyed the industry myth that LNG is safe," said consumer protection advocate Tim Riley, who hosts the website TimRileyLaw.com that documents what he sees as the dangers of the fuel.

"Quite simply, LNG is too damn dangerous and the energy industry has always known it. The American communities facing LNG proposals have listened to the LNG 'safety spin' but have now heard the explosive truth, galvanizing opposition.

"The blast was felt around the world and serves as a wake-up call to private investors, financial institutions and insurance carriers who would risk major losses from another inevitable LNG disaster," Riley declared.

In Weaver's Cove, Massachusetts, Mayor Edward Lambert opposes a local LNG import terminal proposal precisely because of the Algerian disaster.

"This speaks to the credibility of those people who are running around saying how safe this stuff is, saying it doesn't explode. It clearly points to the safety concerns that these terminals don't belong in populated areas."

Local Fire Chief Ed Dawson noted that fires at LNG import terminals are rare but that the Algerian situation illustrates the danger they present. "The chances of it happening here are very remote. But the reality of it is we just had an incident in Algeria. The devastation speaks for itself." (*Emphasis added*)

April 14, 2004

Report sheds new light on LNG blast in Algeria

Full Story: http://www.al.com/news/mobileregister/index.ssf?/base/news/1081934271102960.xml
Document suggests that deadly explosion was caused by gas vapor, not boiler
By BEN RAINES

"A newly released document provides important insights into the chain of events that led to the January explosion of a liquefied natural gas facility in the African nation of Algeria."

"Several scientists who specialize in LNG research said the document indicates that a similar accident could occur at LNG plants like those proposed for Mobile Bay and elsewhere in the United States."

"Initial reports blamed a faulty steam boiler for the massive explosion and fire at the government-owned Skikda, Algeria, plant. Those reports were incorrect, according to the new document presented by Sonatrach, owner of the destroyed LNG plant."

"A PowerPoint display titled "„The Incident at the Skikda Plant: Description and Preliminary Conclusions‟ indicates, instead, that **a large amount of liquid gas escaped from a pipe and formed a cloud of highly flammable and explosive vapor that hovered over the facility. The cloud exploded after coming into contact with a flame source.**"

"Most of the 27 people who died were killed by the force of the blast, according to the report. The report lists a "„few casualties by fire,‟ though the fire burned for eight hours."

"But several scientists who examined the new report told the Mobile Register that the type of accident described in it could occur at an LNG facility in this country, regardless of the type or number of boilers present. Almost any source of ignition, from a cigarette lighter to a pilot light, could have ignited a vapor cloud."

"„I think this tells us that dealing with LNG is a tricky and dangerous business,‟ said James Fay, professor emeritus at the Massachusetts Institute of Technology and one of the nation's leading LNG scientists. „It was apparently a very large gas leak that went on for a while before the explosion. That certainly doesn't give you a lot of faith in their gas detection equipment, with all this gas leaking out. I guess this means sometimes that equipment doesn't work.‟"

"„The fact that there was a vapor cloud is huge," said Bill Powers, an engineer based in California who has studied LNG terminals, siting issues for both onshore and offshore proposals. "We don't know if it was an LNG vapor cloud or an LPG cloud or a mix of both, but, either way, it means it is the kind of accident that could happen here.‟"

"Powers also felt it was noteworthy that Halliburton had conducted a major renovation of the Skikda plant in 1999, updating all of the key safety equipment and computer systems."

"A Halliburton Co. Web site touts the revamped LNG terminal as a model of modern American workmanship."

"„Halliburton Company is pleased to announce that its recently completed Liquefied Natural Gas Revamp Project at Skikda, Algeria, has passed all its performance tests," reads the company news release announcing the project's completion. "KBR's work included extensive revamp of the three LNG trains and associated utilities and auxiliaries and a complete revamp of the complex's electrical power and control systems. ... Over 9,000,000 construction man-hours were expended.‟"

"The three separate LNG regasification plants or "trains" that were revamped by Halliburton were destroyed in the explosion."

"Powers said Halliburton's engineers had missed a weak link in their safety planning for the facility." (*Emphasis added*)

Five killed in Connecticut power plant blast

February 7, 2010 10:06 p.m. EST

STORY HIGHLIGHTS

- Mayor: Workers were purging natural gas pipeline when the explosion occurred
- Explosion happened at about 11:30 a.m. Sunday at Kleen Power Plant in Middletown, Connecticut
- Plant was under construction, about 95 percent complete
- "It was almost like an earthquake," nearby resident tells CNN affiliate WTNH

Middletown, Connecticut (CNN) -- Five people were killed and at least 12 were injured in a gas explosion Sunday at an under-construction power plant in central Connecticut, local officials said.

Residents up to 20 miles away reported hearing the blast at about 11:19 a.m. at the Kleen Power Plant in Middletown, a suburb of Hartford, Connecticut.

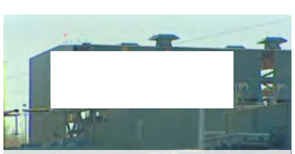
"There is no present or continuing threat to anybody from either substances getting into the atmosphere or of a possible subsequent explosion," Middletown Mayor Sebastian Giuliano said, adding terrorism has been ruled out.

He said plant workers were purging a natural gas pipeline when the explosion occurred.

"Urban search-and-rescue teams are on the premises ... with dogs, attempting to locate and account for further victims," Giuliano said.


Video: Fire official discusses blast


Video: Explosion rocks Middletown


Video: Witnesses describe blast

It's unknown how many people were working in the plant, which was about 95 percent complete, at the time of the explosion. Multiple contractors were involved in the project, Giuliano said, complicating efforts to account for those who may have been on the site.

"[Each contractor] has their own foreperson, their own employee list, so we're trying to sort that out," Giuliano said.

Deputy Fire Marshal Al Santostefano said later Sunday that no one has come forward with any names of missing people and dogs have not detected signs of life beneath the rubble left by the explosion.

The plant was expected to go online this summer, Giuliano said.

Santostefano initially said about 50 people, most of them construction workers, were working at the time, but Giuliano said "we don't know that as a hard number right now."

Map: Blast in Middletown, Connecticut

"What I've been told by the owners of the project is that there could be anywhere from 100 to 200 people working on the site on any given day," Giuliano said.

But Santostefano later said the numbers Giuliano cited were weekday figures, and he repeated his estimate of 50 to 60 people at the site Sunday when the explosion occurred. He said he thought most of those escaped the blast.

A no-fly zone was established over the site because of the unstable structure, Gov. Jodi Rell announced Sunday night.

Middlesex Hospital in Middletown said it received 11 patients from the explosion. One patient with serious injuries was flown to a hospital in Hartford, and another was transferred to Yale New Haven Hospital, according to a statement on Middlesex's Web site. Two others had minor injuries and were treated and released. The remaining seven patients sustained injuries "mainly to the extremities, including broken bones, blunt trauma and abdominal pains," the statement said.

Emergency room physician Dr. Jonathan Bankoff told reporters that some patients reported being thrown 30 or 40 feet by the blast.

Two people were airlifted directly to the Hartford hospital from the scene, Middlesex spokesman R. Brian Albert said. A center was being set up at Middletown's City Hall for relatives of plant workers, he said.

As of late Sunday afternoon, the hospital said it was not expecting more patients from the plant.

After the explosion, it took a while for emergency crews to get into the plant, Santostefano said, because the plant was on fire and the natural gas had to be turned off at the source. No major incidents at the site had been reported since construction began there a couple of years ago, he said.

People miles away reported hearing or feeling the blast.

"It felt like the house was shaking," Peter Moore, who lives about 10 miles away in Durham, told CNN. He said he thought at first there had been a traffic accident on his street or there was a problem with his house.

Moore said his mother, who lives in Woodbridge, about 20 miles away from the plant, also said she heard the explosion, and said it "sounded like someone pounded on the back door a couple of times."

"It was almost like an earthquake," nearby resident Lynn Townsend told CNN affiliate WTNH. She said she heard the explosion and went outside to see "a very big, bright orange flame" between the plant's two smokestacks, and immediately dialed 911.

"It really shook the house," she said. "Everybody was scared. The kids started to cry."

WTNH.com coverage of Middletown explosion

Connecticut State Police Lt. J. Paul Vance told WTNH his agency has received "an immense amount of inquiries" from residents who heard or felt the explosion.

The site is a 620-megawatt gas-fired power plant, according to plant manager Gordon Holk.

We recommend

Suspect in Connecticut murder leaves hospital
Actor Rip Torn posts bail in Connecticut bank case
Murder defendant reportedly in coma; trial delayed

More U.S.

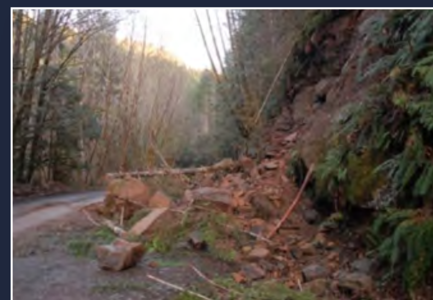
Talk of the town: Who's on 'The List' of alleged sex clients?
U.S. motorist wounds Canadian border officer in shooting, then kills self

Exhibit 25

Geology of the Coos Estuary and Lower Coos Watershed

Summary:

- *Tectonic interactions between the Pacific, Gorda, Juan de Fuca, and North American plates, and the Juan de Fuca and Gorda oceanic ridges are the source of incremental , long-term coastal uplift and infrequent earthquakes when coastal lands suddenly subside.*
- *Tectonic processes, along with long-term cyclical changes in climate and related glacial spread and retreat, have created the bedrock and soil formations found in the project area.*



Landslide along the Smith River in the Oregon coast range.

Local geologic formations are revealed at Coos Head.

What's happening?

This summary describes local geology (e.g., soil and bedrock types), in the context of larger geological processes (e.g., plate tectonics) in four sections:

1. Plate Tectonics – which examines interactions between continental plates, faults, and folds, as well as earthquakes and tsunamis affecting the project area;
2. Geologic Formations – which describes the project area's geologic formations, superficial deposits, and geologic age;
3. Soils – which provides information on soil types within the project area; and
4. Landslides – which describes areas within the project area most at risk for landslides and debris flows.

These four sections are followed by a Background section which provides more in-depth information for each of the sections in this data summary.

Plate Tectonics

Plate Movement: The underlying geology of the Coos estuary and surrounding watershed results from the tectonic interactions between the Pacific, Gorda, Juan de Fuca, and North American (i.e., North American continent) tectonic plates, and oceanic spreading from two ridges (Juan de Fuca and Gorda) (Figure 1)(see also Geology Terminology sidebar). Large-scale plate movements (e.g., slip of the Juan de Fuca plate along the Blanco Transform Fault, and subduction of the Juan de Fuca plate beneath the North American plate) have been coupled with localized sea floor spreading along two ridges: the Gorda Ridge at a rate of 2.3-5.5 cm (0.9-2.2 in) per year, and the Juan de Fuca Ridge at a rate of 4.0 cm (1.6 in) per year (Komar 1997; Clague 1997). Along the Oregon coast, pressure from these tectonic movements of the earth's crust have resulted in the folded and warped outer continental shelf margin and cycles of long-term, incremental uplift of the coastal lands followed by rapid subsidence events (i.e., earthquakes)(Rumrill 2006).

Stratigraphic (i.e., study of rock layers) investigations of rock outcroppings by Nelson et al. (1996, 1998) and analysis of the composition and age of buried microfossils indicate that the South Slough tidal basin has undergone catastrophic subsidence of 0.50-1.0 m (1.64-3.28 ft) at least three times over the past 4,000 years, and possibly as many as nine times.

Geology Terminology

Tectonic Plate – The rigid outermost shell of the planet (crust and upper mantle), is broken into major (e.g., continental plates) and minor tectonic "plates".

Ocean Ridge – Underwater mountain range formed by rising magma in a zone on the ocean floor where two tectonic plates are moving apart.

Subduction Zone – An area where two tectonic plates converge causing one plate to slide beneath the other.

Cascadia Subduction Zone – The area where the Juan de Fuca Plate slides beneath the North American Plate.

Faults – Fractures in the earth's crust caused by compression, tensional, or shearing forces, often associated with the boundaries between tectonic plates.

Slip or Strike-slip Fault – Vertical fractures in the earth's crust where the blocks of land have mostly moved horizontally.

Paleoseismic Faults – Faults that were the source of significant earthquakes (magnitude 6.0 or greater) in the past 1.6 million years

Sources: USGS 2014a; DOGAMI 2009; PNSN n.d.

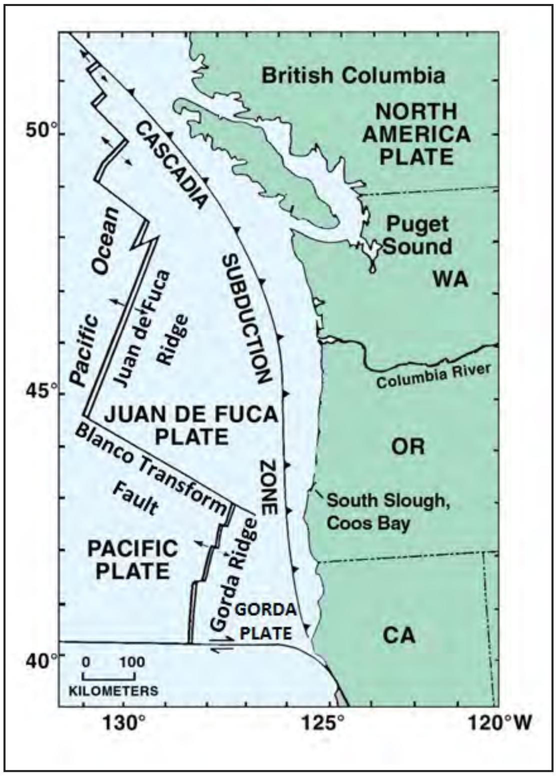


Figure 1: Tectonic components (ridges and plates) in the Pacific Northwest. Arrows on ridges indicate direction of spread. Cascadia Subduction Zone is where the Juan de Fuca Plate is pushed under the North American Plate. Amended from Rumrill 2006

<u>Faults and Folds</u>: The chief geological feature of the Coos estuary is the South Slough Syncline, which is an asymmetric fold with steep sandstone and shale on its western side and gently sloping marine terraces on its eastern side, all of which are offset by several minor cross faults (Rumrill 2006; McInelly and Kelsey 1990)(Figure 2). According to Rumrill (2006), “South Slough marks the point where the Cascadia fold and thrust belt comes onshore; north of Coos Bay most compressional structures occur offshore on the continental shelf and slope”.

Paleoseismic faults in the project area – or faults that were the source of significant earthquakes (magnitude 6.0 or greater) in the past 1.6 million years – were found almost exclusively in the South Slough subsystem (Figure 2). Similarly, nearly all non-paleoseismic faults and folds in the project area are found

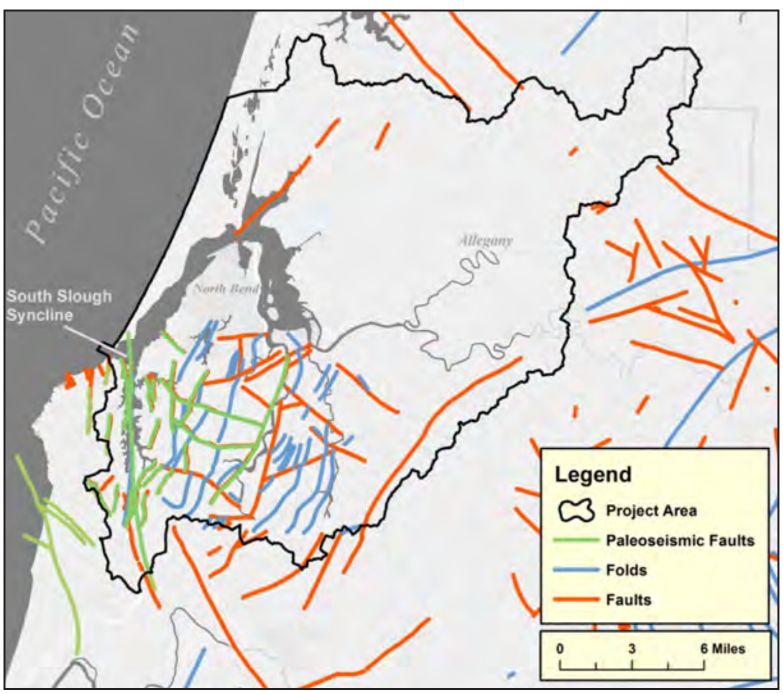


Figure 2: Faults and folds occurring within project boundaries. Paleoseismic faults are highlighted, designating faults that were the source of significant earthquake (6.0 or greater) in the past 1.6 million years. Data: USGS 2005; DOGAMI 2009.

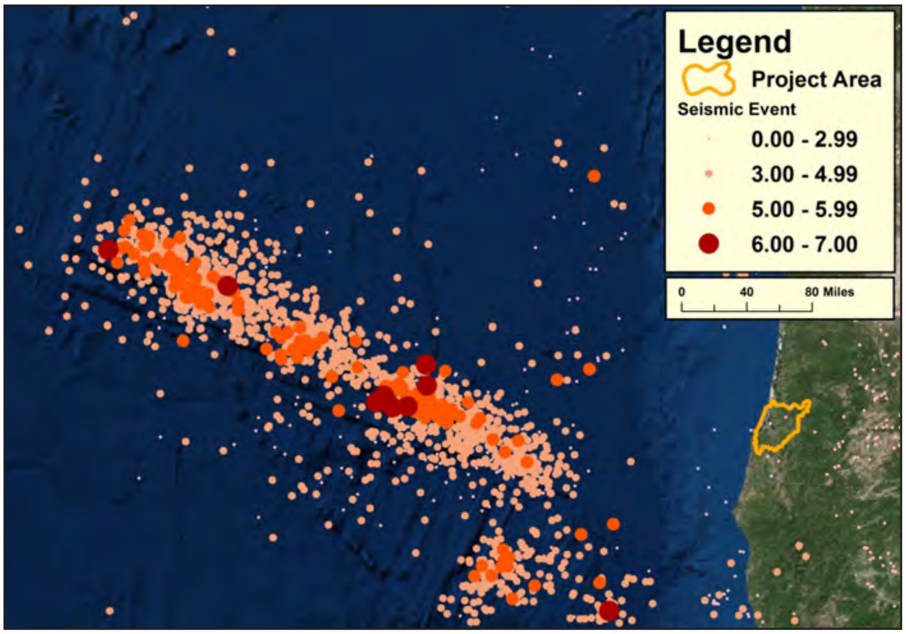


Figure 3: Seismic events between 1969 and 2015.
Data USGS 2015

Year	Month	Magnitude	Depth	Latitude	Longitude
1991	July	6.9	11	42.182	-125.641
1985	March	6.5	10	43.51	-127.561
2008	January	6.3	13	43.785	-127.264
2003	January	6.3	10	44.284	-129.024
1994	October	6.3	20	43.515	-127.427
2000	June	6.2	10	44.513	-130.081
1981	November	6.2	10	43.542	-127.706
2000	January	6.1	10	43.649	-127.257
2012	April	6.0	8	43.584	-127.638

Table 1: Seismic events (between 1969 and 2015) with magnitudes 6.0 or higher. Depth is kilometers below the earth's surface. Data USGS 2015

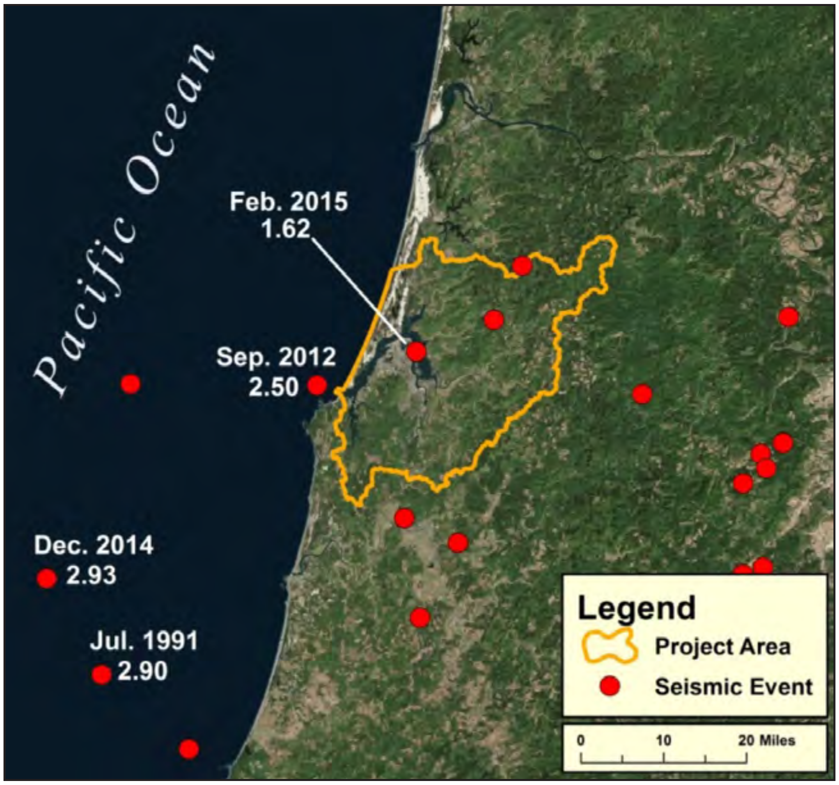


Figure 4: Seismic events (occurring between 1969 and 2015) closest in proximity to the project area. Dates and strength of the highest magnitude events are labeled. Data USGS 2015

in its southern portions (i.e., South, Isthmus and Catching Slough subsystems).

<u>Earthquakes and Tsunamis</u>: Of the over 2,100 earthquakes measured off the Oregon coast since 1965, only nine have been a magnitude 6.0 or higher (Figure 3). The strongest of these (magnitude 6.9) occurred in July 1991 (Table 1). The average magnitude of all earthquakes during that time period was 3.5 and the average depth was 10.7 km (6.6 mi) below the earth's surface. Many earthquakes were concentrated around the Blanco Transform Fault. In contrast, only a few earthquake events were located in close proximity to the project area and those were much smaller in magnitude during the same time period (Figure 4). The largest of these closer proximity earthquakes (2.5 magnitude) occurred just off Cape Arago in September 2012.

Stratigraphic investigations conducted over the past few decades have provided evidence that much of the Pacific Northwest coast has experienced significant (magnitude greater than 8) Cascadia megathrust earthquakes and accompanying tsunamis repeatedly over the past 5,500-6,500 years. These earthquakes occurred every 500-600 years on average (varying from a few hundred years to almost 1,000 years)(Kelsey et al. 2002; Witter et al. 2003). For example, soil cores provide evidence for historically reoccurring rapid coastal subsidence events. Cores taken from current-day tidal marshes in the project area show ancient marsh soils (full of organic materials such as march plant roots) abruptly buried by fine intertidal mud when the coastal land mass rapidly subsided during historic earthquakes. Often these abrupt transitions in the soil cores include a coarse sandy layer full of woody debris deposited during earthquake-generated tsunamis.

The most recent Cascadia megathrust earthquake (magnitude 9) and tsunami on the Oregon coast (including the Coos estuary) occurred on January 29, 1700, caused by a sudden slip of the Juan de Fuca plate beneath the North America plate along the 1,000 km (621 mi) long Cascadia subduction zone (Satake et al. 1996; Rumrill 2006). This caused the land mass to subside an estimated 0.6 m (2.0 ft) (Leonard et al. 2004). Estimates of subsidence from future mega-thrust earthquakes in Coos Bay range from 0-1.5 m (0-4.9 ft) (Leonard et al. 2004) while maximum subsidence, modeled for this area, could be as high as 2 m (7 ft)(Witter et al. 2011). According to Rumrill (2006), “the probability of a future earthquake and coastal subsidence event is conservatively estimated at 10-20% within the next 50 years (or 20-40% within the next 100 years)”.

Lately, seismic activity along the subduction zone appears to have fallen off, leaving the zone “eerily quiet” (Banse 2014). Quoted in several northwest media outlets in December, 2014, Doug Toomey, a geophysics professor at the University of Oregon, said, “all of Cascadia is quiet. It’s extraordinarily quiet when you compare it to other subduction zones globally” (Banse 2014). In 2011, Toomey and other scientists began the Cascadia Initiative, a four-year study in which seismometers were deployed at 160 sites along the entire Cascadia subduction zone to help determine what that silence means. If they find the boundary between the two plates is fully locked, pressure will continue to build until another serious earthquake occurs. “If it is completely locked, it means [the Cascadia subduction zone] is increasingly storing energy and that has to be released at some point.” (Toomey, on Banse 2014).

Geologic Formations and Deposits

Tyee and Coaledo formations make up the vast majority of the underlying bedrock in the project area (71% combined)(Figure 5). Both formations are sandstones with minor siltstone embedded within (Beaulieu and Hughes 1975)(see definitions in sidebars and in Table 2). Landforms surrounding most of the South Slough shoreline and eastern portions of the lower bay are composed primarily of marine terrace deposits (Figure 5). The remainder of the lower bay is made up of eolian deposits (wind-generated deposits: in this case, dune sand) and beach deposits, while alluvial deposits (river-formed) are found under and along each major tributary to the Coos estuary. Man-made fill deposits can be found under most of the project area’s low-lying urban centers.

The Coos Bay Coal Field (oriented north to south and roughly 30 mi long by 12 mi wide, overlaps the Coaledo formation), lies under North Bend, Coos Bay, Isthmus Slough and Catching Slough (and their tributaries), and the Lower Coos River, and extends down to the Coquille River (DOGAMI n.d.)(Figure 5). From the late nineteenth century through the mid-twentieth century extensive coal mining and geologic testing occurred in the Coos

Geologic Formation

A geological formation is a rock unit that is distinctive enough in appearance that a geologic mapper can tell it apart from the surrounding rock layers. It must also be thick enough and extensive enough to plot on a map.

Source: Wilkerson 2001

Geologic Deposits

Geologic deposits (superficial) are recent (quaternary: 2.6 million years old or less) unconsolidated sediments, soil or rocks added to a landform, generally named according to their origin (e.g., beach deposit, landslide deposit). Older deposits are referred to as bedrock.

Source: Wikipedia 2015b

Sandstone

Sandstone (sometimes known as arenite) is a medium-grained sedimentary rock composed primarily of minerals or rock grains cemented together.

Siltstone

Siltstone is sedimentary rock made up of cemented together silt particles, similar to shale, but does not demonstrate fissility (breaking along planes into sheets).

Source: USGS 2014b

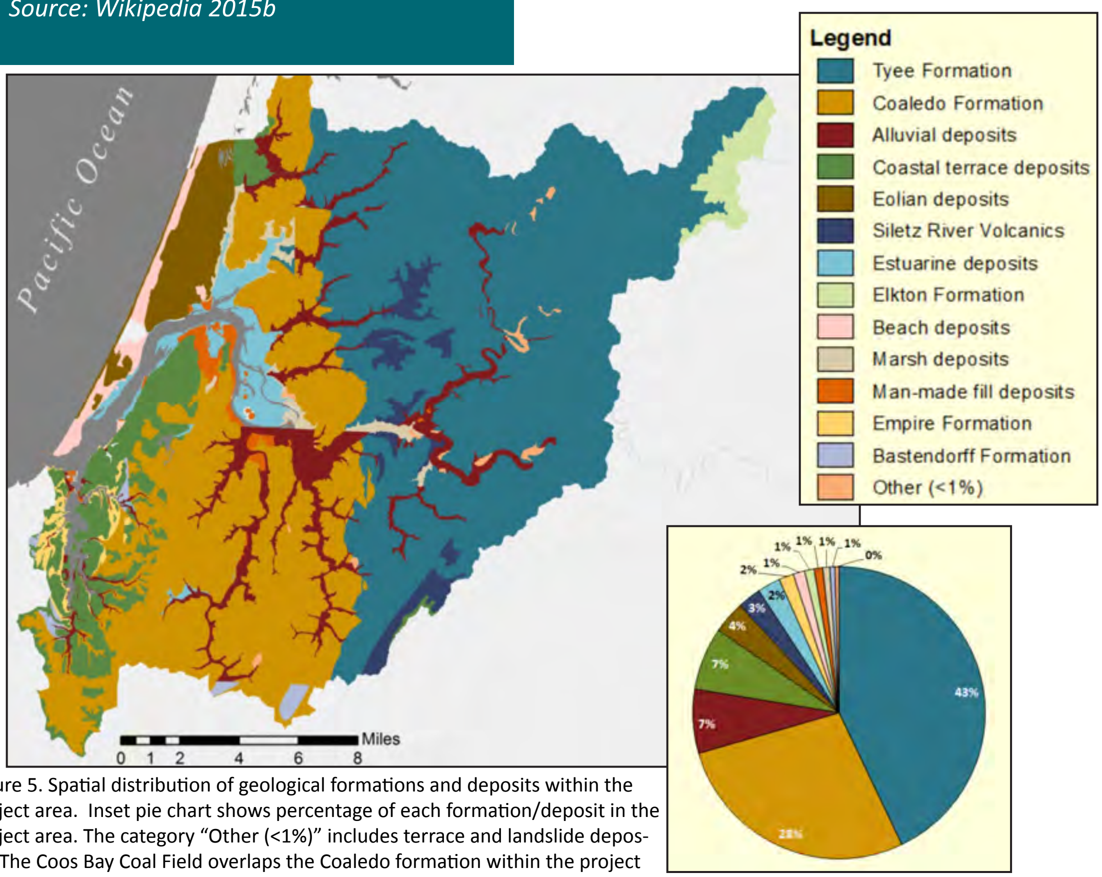


Figure 5. Spatial distribution of geological formations and deposits within the project area. Inset pie chart shows percentage of each formation/deposit in the project area. The category "Other (<1%)" includes terrace and landslide deposits. The Coos Bay Coal Field overlaps the Coaledo formation within the project area, but the coal field is not shown in its entirety. Data: DOGAMI 2009

Geologic Unit	Bedrock Description	Age	Structure
Alluvial deposits	Silt, sand, and gravel filling channels of present day streams/rivers.	Quaternary	
Bastendorff Formation	3,000 ft of shale and siltstone with thin (50') sandstone	Late Eocene	Major synclines
Beach deposits	Fine-grained sand	Holocene-present	
Coaledo Formation	Coarse to fine-grained cross-bedded, deltaic sandstone and minor siltstone	Late Eocene	Moderately to tightly folded with steep dips
Coastal terrace deposits	Compact, horizontally bedded, deeply weathered silt, sand and clay	Quaternary	
Elkton Formation	Thousands of feet of clayey siltstone with minor beds of	Mid-Eocene	Gently folded and
Empire Formation	Thick sandstone beds with very minor quantities of siltstone	Pliocene	Gently dipping folds
Eolian deposits	Fine-grained sand	variable	
Estuarine deposits	Horizontally bedded sand, silt, and clay, rich in organic material	Holocene-present	
Landslide deposits*	Unstratified mixture of bedrock fragments	Holocene	
Man-made fill deposits	Dredge spoils, sand, silt, clay, woodchips	<100 years	
Marsh deposits	Horizontally bedded sand, silt, and clay, rich in organic material	Holocene-present	
Siletz River volcanics*	Basaltic pillow lava flows composed of basaltic siltstone, sandstone, tuff and conglomerate. Originated from oceanic crust.	Eocene	
Terrace deposits	Sand, silt, clay gravel, cross-bedded	Quaternary	
Tyee Formation	Thousands of feet of thick-bedded sandstone and minor rhythmically bedded siltsone	Mid-Eocene	Gently folded

Table 2: Descriptions of geological formations and deposits in the project area. Source: Beaulieu and Hughes 1975; except those marked with an asterisk* sourced from USGS 2014b

Bay Coal Field. Nearly 2.5 million tons of coal were extracted from this coal field between 1882 and 1918 (Duncan 1953; DOGAMI n.d.). Mining ceased in the 1920's primarily due to competition from California fuel oils and higher grade coal from Utah and Wyoming (Duncan 1953; DOGAMI n.d.). Although coal mining no longer occurs in the project area, in the mid-2000s, portions of the coal field were explored to determine its potential for natural gas production using hydraulic fracturing techniques.

Geologic Age of the Project Area

The project area is composed of bedrock formed in the Cenozoic era (65 million years ago-present), most of which was created during its Eocene epoch (Figure 6; Table 3). According to Rumrill (2006), sandstone, siltstone, and shale were deposited deep in the Pacific ocean and in shallow coastal waters over the past 50 million years, from the Eocene epoch through the Quaternary period. During the marine regression in the middle to late Eocene epoch (38-45 million years ago), sea level dropped, which allowed Coos Bay to emerge as a distinct, wave-dominated (as opposed to river-dominated) deltaic coastal basin.

Beginning in the middle Eocene epoch (about 40-48 million years ago), sediments that largely form the present-day bedrock were laid down during repeating marine transgressions (period of high sea level) and regressions (period of low sea level)(Rumrill 2006). These fluctuations were caused primarily by

Geological Time Scale

Span of time since the Earth's creation, divided by major geological events, strata composition, or radiometric dating. Eon is the largest division, followed by Era, Period, Epoch and finally Age.

Source: Wikipedia 2015a

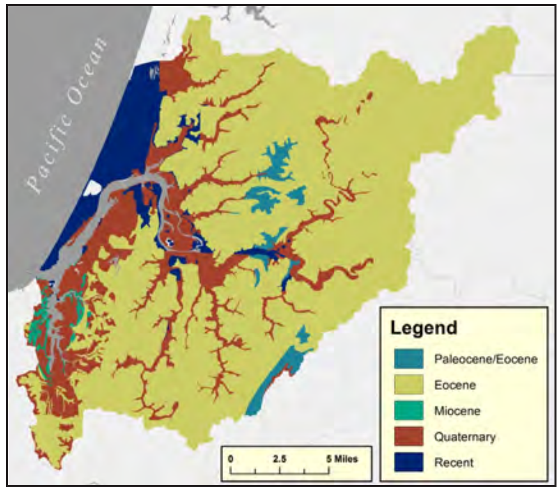


Figure 6: Spatial distribution the project area's geologic time scale. Legend ordered from oldest to most recent. Data: DOGAMI 2009

cyclical changes in climate that led to advances and retreat of continental glaciers, and subsequent rise and fall of sea level. These periods of major seal level fluctuations caused the continental shoreline to migrate back and forth tens of kilometers between the sea level extremes.

For example, beds of siltstone, mudstone, and sandstone formed in the middle Coaledo Formation beds (see "Formations" above) were laid down in deeper coastal waters during a marine transgression, while upper Coaledo beds (siltstone, mudstone, coal, and conglomerate) were deposited in shallow water during a subsequent regression (Rumrill 2006).

According to Rumrill (2006), absence of sediments for nearly 30 million years, dating from the Oligocene and early Miocene (8-36 million years ago), indicates a significant period of non-deposition, probably related to a combination of the onset of "tectonic plate deformation along the Cascadia subduction zone", glacial advance, and periods of low sea level. Rumrill (2006) discusses another gap of about four million years long occurring 6-2 million years ago, separating older formations

Era	Period	Epoch	Geologic Age (million years ago)
Cenozoic	Quaternary	Holocene	0.01-present
		Pleistocene	2.6-0.01
	Neogene	Pliocene	5.3 - 2.6
		Miocene	23.0-5.3
	Paleogene	Oligocene	33.9-23.0
		Eocene	56.0 -33.9
		Paleocene	65.0-56.0

Table 3: Definition of geological ages in the Cenozoic era.

such as the Miocene epoch's Empire formation from more recent Pleistocene marine terraces and Holocene estuarine and sand deposits.

Soils

This section discusses soil types found in the project area. Definitions of soil types discussed in this section can be found in Table 4.

<u>Estuarine Soils</u>
Sediments in the estuarine tidal channel vary from coarse-grained sand to fine-grained sand, silt and clay (Rumrill 2006). See "Sediment Composition" summary in "Chapter 10: Sediment" for more detail on estuary sediments.

Tide flat sediments are primarily open sand flats and mudflats, which are composed of Udorthents, a combination of sand, silt, mud or organic materials, largely devoid of emergent vegetation (Haagen 1989). Mudflats typically occur in regions of the estuary that experience low tidal energy while sand flats occur in areas of high tidal energy (Rumrill 2006).

In the South Slough estuary, sand flats frequently occur on the inside of major bends in the tidal channel. These sand flats frequently have sand ripples or waves, the patterns of which are directly related to water velocity (Rumrill 2006).

According to Rumrill (2006) tidal beaches within South Slough are generally steep (9-15% slope) and sediments increase in mean grain size with depth, and decrease in mean grain size along the estuarine gradient (i.e., sediment is more fine further away from the mouth of the estuary). Most beach sediments are well-sorted. The decrease in mean sediment grain size along the estuarine gradient (from the high-energy estuary mouth to the low-energy upper estuary) is most likely a result of the gradual decrease in velocity of tidal currents, which in turn reduces their capacity to carry larger sediment particles (Arkett 1980, in Rumrill 2006).

<u>Tidal Wetland Soils</u>
Soils in the tidal wetlands of the Coos estuary are predominately Fluvaquents-Histosols, which, typical of permanently or frequently saturated soils, are particularly rich in organic matter (Haagen 1989).

Rumrill (2006) described surface soils within South Slough riparian areas, forested wetlands, and emergent freshwater marshes as typically sandy loams, also rich in organic matter.

Soil Complex

Soil complex is defined as two or more soils which are so integrated that they cannot be separated at the map scale.

Soil Association

Soil association is defined as two or more soils that are intricately mixed but could still be separated at the map scale (although it's not practical to do so).

Source: Haagen 1989

Soils	Abridged Definition (Haagan 1989)
Bandon Sandy Loam	Deep, well drained soils, with a thick (1") covering of organic litter, found on dissected marine terraces. Top 5" is dark gray/brown sandy loam, followed by 25" dark red/brown sandy loam subsoil, 13" pale brown cemented sandy material and a substratum of yellow/brown loam.
Bullards-Bandon-Blacklock	Loamy and sandy soils derived from marine sediment and found on marine terraces.
Bullards (58%)	See Bullards Sandy Loam above
Bandon (20%)	See Bandon Sandy Loam above
Blacklock (18%)	Poorly drained, nearly level (0-3%) soils on depression areas of marine terraces. Black fine sandy loam surface (9") soil, with upper subsoil (2") black mucky loam, and lower subsoil (37") with a yellow/brown cemented sand. Base substratum is light olive/red or brown sand.
Bullards Sandy Loam	Deep, well drained soils, with a thick (3") covering of organic litter, found on dissected marine terraces. Surface soil (7") is dark gray/brown sandy loam, with 34" dark red/brown gravelly sandy loam subsoil beneath, under which is yellow/brown sand.
Coquille-Nestucca-Langlois	Poorly drained, silty and clayey soils found on flood plains; formed from alluvial processes.
Coquille (22%)	See Coquille Silt Loam below.
Nestucca (19%)	Poorly drained soils found in depressions with mottled dark brown silt loam on the surface (14"). Subsoil is mottled dark gray/brown silty clay loam (26"). Substratum is mottled olive brown silty clay.
Langlois (14%)	Very poorly drained soils found in depressions and old tide flats. A thick (5") dark gray/brown peat layer sits atop surface soils. Surface soils are mottled dark gray/brown silty clay loam (10") and dark gray/brown silty clay upper subsoil (20") with dark gray clay lower subsoil (60").
Other minor soils (45%)	Combination of minor elements.
Coquille Silt Loam	Deep, poor draining soils, found primarily on flood plains (formed from alluvium). Thick (14") surface layer is dark gray/brown silt loam with gray/olive silty clay loam subsoil. Substratum is dark gray silty clay loam.
Dement Silt Loam	Deep, well drained soils derived from silt or sandstone, frequently found on ridgetops. Surface is dark gray/brown silt loam (7"), followed by red/brown silty clay loam subsoil (38"). Under this is found weathered sedimentary rock.
Dune Land	Shifting fine and medium grained sand, extremely permeable.
Dune Land-Waldport-Heceta	Sandy soils found on sand dunes and deflation plains.
Dune Land (30%)	See Dune Land above
Waldport (29%)	Found on stabilized sand dunes (leeward side of deflation plains). Surface 4" is dark gray/brown fine sand with dark yellow/brown fine sand beneath.
Heceta (18%)	Deep poorly drained soils found in deflation plains and depressions between dunes. Surface layer (4") is dark gray/brown fine sand with mottled gray/brown sand beneath.
Other minor soils (23%)	Combination of minor elements.
Fluvaquents-Histosols Complex	Level (slope ≤ 1%) tidelands of bays, inlets and estuaries
Fluvaquents (50%)	Covered by mean high water. Layers of mineral and organic material in varying thicknesses. Surface layer is generally sandy, silty or clayey depending on tidal currents.
Histosols (40%)	Covered by mean higher high water. Thick (16") organic layer over alternating layers of mineral and organic matter.
Geisel Silt Loam	Deep, well drained soil found on side slopes, derived from sedimentary rock. Surface layer is dark red/brown silt loam (4" thick). Upper subsoil (26") is dark red/brown silt loam and silty clay loam, while lower subsoil (24") is dark red/brown silty clay. Weathered siltstone forms base rock.
Milbury-Bohannon-Umpcoos Association	Moderately deep and shallow, gravelly loamy soils, derived from sedimentary rock
Milbury (40%)	Derived from sandstone, moderately deep well drained soil with very gravelly black sand loam on surface (10") and dark gray brown very cobbly loam subsoil (26"). These sit atop consolidated sandstone.
Bohannon (27%)	Moderately deep, well drained soil derived from arkosic sandstone. Surface (11") is very dark brown loam and gravelly loam; subsoil is dark yellow/brown gravelly loam (20"). Base substratum is weathered fractured sandstone.
Umpcoos (22%)	Shallow, well drained soils derived from sandstone, found on rock outcrops and ridgelines. Surface (3") is dark gray/brown very gravelly sand loam. Subsoil is brown very gravelly sandy loam (13"). Hard sandstone is underneath.
Other soils (11%)	Combination of minor elements.
Millicoma-Templeton Complex	Found on ridgetops and side slopes
Millicoma (55%)	Deep well drained, derived from sandstone. Surface layer is very dark/gray brown gravelly loam (18") with very gravelly dark brown loam subsoil (17"). Underneath that is partially weathered sandstone.
Templeton (25%)	Deep well drained, derived from sandstone. Surface layer is very dark brown silt loam (16") with red/brown/yellow silty clay loam subsoil (26"). Weathered fractured siltstone is under that.
Salander and other soils (20%)	Salander - see Salander Silt Loam below; small areas of clay loam or soils with ≤ 35% rock fragment.
Preacher-Blachly Association	Found on broad ridgetops and benches.
Preacher (50%)	Found in concave areas, deep, well drained soil derived from arkosic sandstone. Surface is organic litter (4") with dark gray/brown loam (14"). Subsoil is dark yellow/brown clay loam (34"). Base substratum is yellow brown clay loam.
Blachly (35%)	Deep, well drained soil, derived from basalt or sedimentary rock. Surface is red/gray or dark red/brown silty clay loam (7"). Upper subsoil (45") is dark red or yellow/red silty clay; lower subsoil (8") is yellow/red silty clay loam.
Bohannon, Digger (15%)	See Bohannon in Milbury-Bohannon-Umpcoos above.
Preacher-Bohannon Loams	Deep gravelly and loamy soils found on broad ridgetops, benches and steep side slopes.
Preacher (50%)	See Preacher in Preacher-Blachly Association above.
Bohannon (30%)	See Bohannon in Milbury-Bohannon-Umpcoos above.
Milbury, Digger, Blachly (20%)	Milbury - see Milbury-Bohannon-Umpcoos above. Blachly - see Preacher-Blachly Association above. Digger soil is moderately deep well drained derived from sedimentary rock. Organic layer (1") thick on top has dark brown gravelly loam (6") underneath. Upper subsoil (3") is dark yellow/brown gravelly loam; bottom 18" is brown very gravelly and cobbly loam. Base rock is brown extremely cobbly loam (4") with weathered, fractured sandstone beneath.
Rinearson Silt Loam	Deep, well drained soil, found on ridgetops and side slopes, derived from sedimentary rock. Surface soils are dark red/brown silt loam (6"). Upper subsoil (12") is dark/red brown silt loam; lower subsoil (24") is red/brown silty clay loam. Base substratum is weathered sandstone.
Salander Silt Loam	Deep, well drained soil, found on side slopes, derived from sedimentary rock. Surface layer (26") and top layer of subsoil (14") is dark red/brown silt loam. Lower subsoil (25") is dark red/brown silty clay loam.
Templeton Silt Loam	Deep, well drained soil, found on ridgetops and benches, derived from sedimentary rock. Surface layer is very dark brown silt loam (16") with red/brown/yellowish red silty clay loam subsoil (26"). Soft weathered fractured siltstone makes up the base substratum.
Udorthents	Level (slope ≤ 1%) flood plains, marshes, and tidal flats on major water bodies (including filled and leveled areas). Soils are a mixture of sand, silt or clay materials; dredge spoils also consist of dune sand and wood chips.
Wintley Silt Loam	Deep well drained souls found on high terraces, derived from alluvial processes. Surface is topped with 1" undecomposed organics, followed by 4" dark brown silt loam. Upper subsoil (12") is dark brown silty clay loam; lower subsoil (31") is brown silty clay and silty clay loam. Base substratum is dark yellow/brown very gravelly loam.

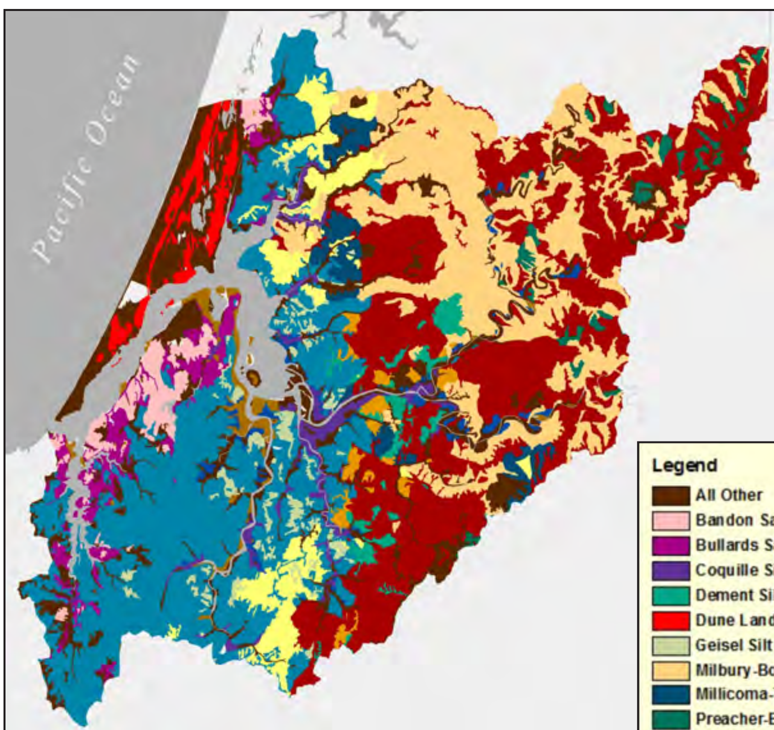
Table 4: Most common soil types, soil complexes, and soil associations found in the project area.

Dune Soils

The Coos Bay Dune Sheet is a mass of sand that extends, unbroken but for the mouths of rivers and streams, from Haceta Head to Cape Arago, making it the largest dune sheet in North America and the only 'oblique-ridge dune' in the world (Cooper 1958; Crook 1979). Dune lands in Coos County are generally made up of DuneLand-Waldport-Heceta soil types. Extensive portions of the dunes have been stabilized by plantings of the invasive European beachgrass (*Ammophila arenaria*), which began in 1910 (for more information on this, see "Vegetation" summary in "Chapter 18: Non-Native/Invasive Spp.").

Upland and Lowland Soils

Fifteen principle soil types are found in the lower Coos basin (Figure 7). Of those, three predominate and are found in distinctly different areas of the landscape. Most common are Preacher-Bohannon loams (24% of total soil cover), found in a patchy, north-south oriented band of uplands east of the bay, along the western slopes and foothills of Blue Ridge, and in the Millicoma highlands. Templeton silt loam (23% of soil cover) extends from the uplands of the South Slough basin east through the drainages of Isthmus and Catching Sloughs, across the highlands of Pony Creek Reservoir, along the eastern slopes of Coos Bay and across the uplands between North



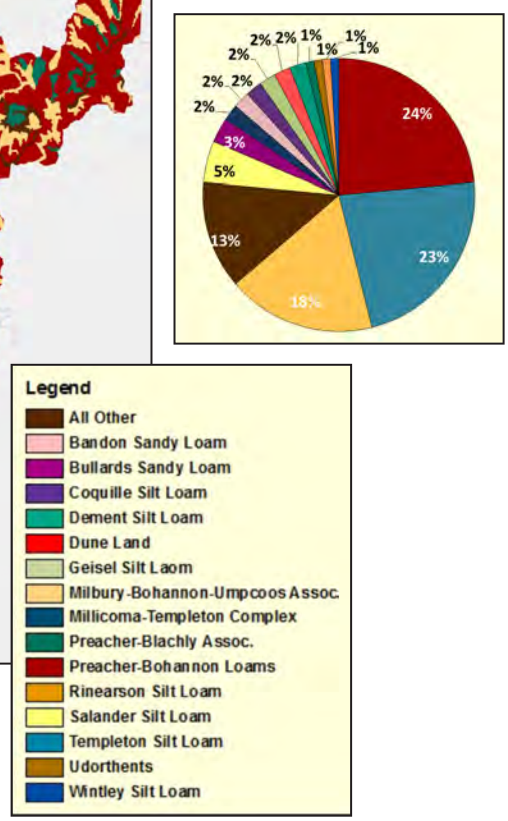


Figure 7: Distribution of different soil types in the project area. Inset pie chart shows percentage of each soil type that makes up the project area. Soil types for both figures were grouped by series (e.g., Bandon Sandy loam 0-7% slopes and Bandon Sandy Loam 7-12% slopes were grouped as Bandon Sandy Loam). Data: USDA 2000

Slough and Haynes Inlet. The Milbury-Bohannon-Umpcoos association (18% of cover) is interspersed with the Preacher-Bohannon series in the upper watershed.

Except where otherwise noted, the following soil descriptions for several major sub-basins, are taken from an assessment of Coos estuary tributary basins conducted by the Coos Watershed Association (CoosWA 2006).

<u>North Slough</u>
North Slough differs in its soils from other sub-basins in that it is dominated by the very soft, highly erosive sandstones of Dune Land-Waldport-Heceta and Bullards-Bandon-Blacklock soils.

<u>Palouse and Larson Sloughs</u>
Three general soil types dominate the Palouse and Larson Slough sub-basin: Dune land-Waldport-Heceta, which is common to dune areas, Templeton and Salander loams, common to the lowland area, and Milbury-Bohannon-Umpcoos, found in the uplands.

<u>Kentuck Slough</u>
Soils in the Kentuck Slough sub-basin consist of Templeton and Salander loams in the lowlands, and Preacher-Bohannon loams in the uplands. The headwaters of Kentuck Creek are on the Milbury-Bohannon-Umpcoos soil type.

<u>Willanch Slough</u>
General soil types in the Willanch Slough sub-basin are Templeton and Salander loams (lowlands) and Preacher-Bohannon loams, (uplands).

<u>Echo Creek</u>
The Echo Creek sub-basin hosts three general soil types: the Coquille-Nestucca-Langlois soil, found in level areas, areas along the bay, and Coos River; Templeton and Salander loams (lowlands), and the Preacher-Bohannon loams (uplands).

<u>Lower Millicoma and South Fork Coos Rivers</u>
According to CoosWA (2008), Preacher-Bohannon loams are the most prevalent soils in Lower Millicoma and South Fork Coos River sub-basin. Other soils include Milbury-Bohannon-Umpcoos on steep slopes and poorly draining, clay Coquille-Nestucca-Langlois soils along floodplains.

<u>South Slough</u>
Haagen (1989) shows the primary soils in this sub-basin as Templeton loams, with some Bullards-Bandon-Blacklock group.

Landslides

According to Wang et al. (2002), Oregon economic losses due to landslides exceed $10 million/year. In years with heavy storm events, losses can exceed $100 million. These losses are expected to increase as the state’s human population increases, expanding current land uses.

Landslides occur frequently in the Coos region, as they do throughout much of the central Coast Range. The Oregon Department of Geology and Mineral Industries (DOGAMI) has compiled an inventory of historic landslide locations, which helps identify areas potentially prone to future land failures (Figure 8).

Oregon Department of Forestry (ODF) developed debris flow (a type of landslide – see Background below) hazard maps, based on slopes derived from USGS digital elevation models. Slopes >40% and an area greater than 150,000 ft^2 were considered moderately hazardous. Tyee Formation slopes >65% over an area of 100,000 ft^2 or >60% for more than ⅓ the total basin area were considered a high risk for debris flows. Other formations were considered a high risk if they had a slope >70% and an area exceeding 150,000 ft^2 or ¼ total basin area. Extreme hazard values were assigned to locations where debris flows have occurred frequently over the past 35 years.

Areas of high and moderate debris flow risk have been mapped for the project area using these data (Figure 9). The hills east of the main Coos estuary are at considerably higher risk for debris flow occurrences than lands closer to the ocean. In fact, the Coos River subsystem has the highest percentage of both high (9.5%) and moderate (18%) lands at risk for debris flow events (Figure 10). When taken as a whole, 33% and 12% of the entire project area is at moderate and high risk, respectively, for debris flows.

Background

Plate Tectonics

Rumrill (2006) describes the Coos estuary as being formed by the interactions of "several coastal geomorphic processes in the recent geologic past" (thousands to tens of thousands of years ago), including "slow coastal uplift and sudden subsidence" (driven by tectonic movement of offshore crustal plates); "regional transgression and regression of the sea as a result of ice-age glacial advance and retreat"; and "fluvial erosion of a major riverine drainage system caused by differential coastal uplift".

Folds and faults

Long-term seismic shifting of the North America and Juan de Fuca plates contributed to east-west compression that formed the South Slough syncline and other folds throughout the southern Oregon coastal region. Folding and faulting cause different areas of the coast to rise at different rates, significantly altering the topography of the Coos drainage basin (Kelsey et al. 2002). For example, before the creation of the current coastal terraces (which were created by folding and faulting processes), the Coquille River drained into the Pacific Ocean through Isthmus and South Sloughs (Baldwin 1945; Nyborg 1993 as cited in Rumrill 2006). Evidence of this can be seen along several outcrops in the South Slough where Pleistocene alluvial floodplain materials (including aquatic invertebrate fossil assemblages) are identical to those found at the mouth of the Coquille River (Nyborg 1993 as cited in Rumrill 2006).

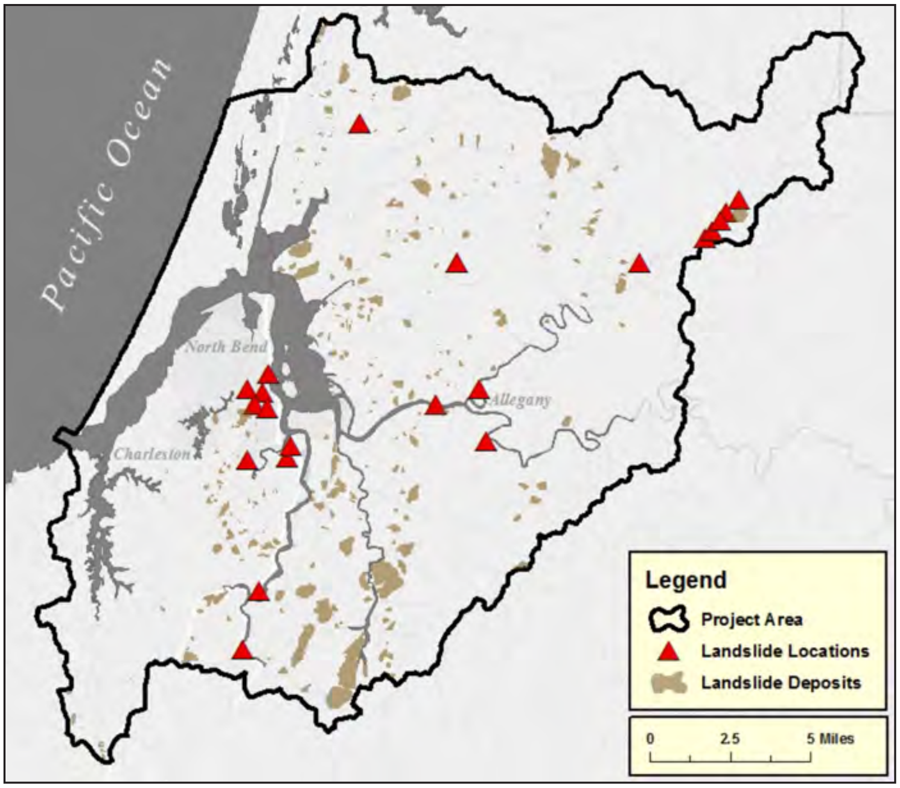


Figure 8: Inventory of historic landslides (1849-2013), identifying landslide-prone areas, which may be susceptible to future landslides. Landslide deposits include debris flow fans and talus extent. Data: DOGAMI 2014

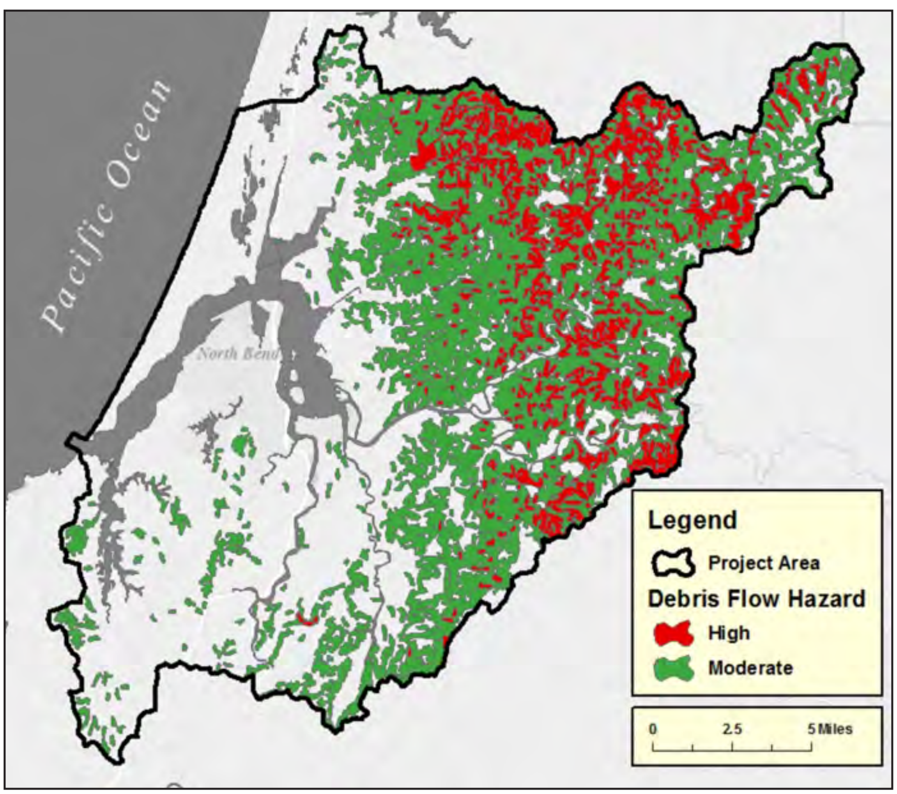


Figure 9: Distribution of lands that are highly or moderately at risk of debris flows in the project area. Data: ODF 2000.

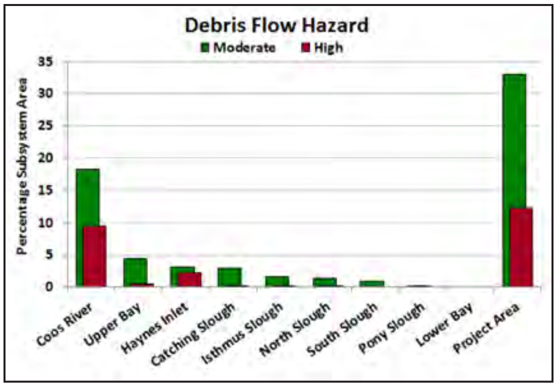


Figure 10: Percentage of each subsystem and entire project area that is at high and moderate risk for debris flow. Data: ODF 2000.

Other evidence of subduction processes were described by Witter et al. (2003), who found that stepped marine terraces occurring in the hills surrounding the Coos estuary are a result of ocean-derived sediments scraped off the Juan de Fuca plate as it slid down under the North American Plate.

Earthquakes

Pressure that accumulates in the earth as a result of forces and movements of plates is released episodically during earthquakes. Three types of earthquakes affect coastal Oregon: Cascadia megathrust, deep intraplate, and crustal earthquakes (see sidebar). The most frequently occurring of these are crustal earthquakes, which occur along active fault lines (Rumrill 2006). Seismic studies conducted near the Coos estuary's Jordan Cove indicate fewer deep intraplate earthquakes occur in the Coos Bay area compared with areas to the north and south (GRI 2013). The largest earthquakes in our area tend to occur along the Cascadia Subduction Zone boundary and can cause sudden coastal subsidence of from 0.5-2 m (1.64-6.56 ft)(Darienzo and Peterson 1990 as cited in Rumrill 2006).

According to NOAA's Pacific Northwest Seismic Network (PNSN n.d.), the Cascadia Subduction Zone is locked by friction at depths shallower than 30 km (16.6 mi). Strain continues to build slowly as the tectonic forces act (including expansion at the Juan de Fuca Ridge). Eventually, when the frictional strength is exceeded, the plates will slip past each other, causing a megathrust earthquake. The fault's frictional properties change with depth, such that immediately below the locked part is a strip (called the transition zone) that slides slowly and slips a few centimeters every year or so. These small slips relieve the stress on the plate boundary in one location, but add to the stress on the fault elsewhere. Below the transition zone geodetic evidence suggests that the faults slide continuously and silently past one another.

Tsunamis

Tsunamis are triggered when the elevation of the coastal margin suddenly changes, displacing a large volume of water. Tsunami waves propagate rapidly through the open ocean and can reverberate throughout the entire Pacific Ocean basin in the 24-hour period following a sufficiently strong earthquake. In the Pacific Ocean, tsunamis move at speeds of ~435 mph, losing little energy as they travel (Petroff n.d.).

Geologists examined sediments deposited in the Coquille River estuary (Witter et al. 2003) and those of coastal lakes (Kelsey et al. 2005)

Local Earthquake Types

<u>Cascadia Megathrust</u> – The most powerful recorded earthquakes in the area (magnitude 8-9 or higher), Cascadia megrathrust earthquakes are caused the by sudden release of built-up energy when the Juan de Fuca Plate (locked against the North American Plate) is suddenly released and the plates slip past each other.

<u>Deep Intraplate</u> – Deep intraplate earthquakes occur when the Juan de Fuca plate cracks as it is bent deep underneath the North American Plate (at depths from 30-70 km [19-43 mi]). Deep intraplate earthquakes occur about every 30 years at magnitudes as high as 7.5. Because they usually occur under the Cascade and Coastal ranges, these earthquakes can be the most damaging to population centers.

<u>Crustal</u> – Crustal earthquakes occur on shallow faults (to 35 km [22 mi] deep) in the North American Plate and are relatively common off the southern Oregon coast (maximum magnitudes <7).

<u>Earthquake Magnitude</u> (i.e., strength), originally based on the Richter Scale but now based on the moment magnitude scale (MMS), quantifies the energy released by an earthquake.

Sources: PNSN n.d.; DOGAMI 1996

for evidence of periodic tsunamis, and to improve their understanding of the impact of movements and interactions of crustal plates of the Cascadia Subduction Zone on the landforms and elevation of the southern Oregon coast, including the Coos estuary. Witter and colleagues traced 12 cycles of uplift and subsidence in the record of low-lying forests and tidal wetlands over the last 6,700 years while Kelsey and colleagues found a record of repeated local tsunamis in the sediments of Bradley Lake in Curry County.

Soils

<u>Tidal Areas</u>

According to Rumrill (2006), tide flats in the Coos estuary likely formed during the past 1,000-2,000 years as estuarine sediment eroded from marine terraces, filling in the Coos estuary tidal basin and creating the tide flats we see today.

Other sources of tide flat sediments are terrestrial runoff, oceanic deposition, and biotic material (Rumrill 2006). For example, much of the mud, silt, and clay within the estuarine tidal basin enters South Slough from Coos Bay and the nearshore Pacific Ocean during flood tides (Wilson 2003 in Rumrill 2006).

Sand flats are created largely from land sources, including erosion of nearby cliffs, then transported by high velocity tidal currents (Rumrill 2006).

Tide flats are often highly channelized with shallow drainage channels, which facilitate a continued cycle of erosion and deposition as sediments are re-suspended, transported, and deposited with every tidal cycle (Rumrill 2006).

Tidal Wetlands

Tidal wetland soils can inform us about sea level rise rates. For example, Rumrill (2006) explains that "Prevalence of peat layers in the upper 1.0-1.5 m (3.28-4.92 ft) of sediment cores taken from brackish marshes in many parts of the Coos estuary suggests a reduction in the rate of sea-level rise or an increase in the rate of sedimentation over the past 1,000-1,500 years".

Landslides

Landslides are typically triggered by heavy rain. Less commonly they are caused by earthquakes, road construction, rapidly melting snow, or a combination of these and other events (DOGAMI 2008).

A particularly damaging landslide is known as a debris flow. A debris flow (synonymous with mudslide, mudflow, or rapidly moving landslide) is a fast moving (exceeding 30 mph) mixture of water, rock, soil, and vegetation. Debris flows begin as small landslides, and then, upon entering a steep sloping stream channel, gain momentum and more debris, until they finally end as massive deposits at the outlet of the channel (DOGAMI 2008; ODF 2012).

Debris flows can travel long distances, sometimes scour the channel down to bedrock, and frequently cause major structural damage to houses and roads. They are extremely hazardous, especially in populated areas (Robison et al. 1999; ODF 2012). It should be noted, however, that debris flows also deliver large wood to streams where they add complex structure that provide high quality fish habitat (ODF 2012).

In 1996, two very large storms severely affected western Oregon, one of which was a 100-year rain event that set an all-time one-day precipitation record at North Bend (6.67 inches in 24 hrs)(Robison et al. 1999). Both storms triggered large numbers of landslides in western Oregon, prompting ODF to take a closer look at activities, such as forest-road building and logging, that were thought to play a role in landslides. This report (Robison et al. 1999) examined eight locations affected by these two storms and found that lands with the highest hazards for landslides were found on slopes >70-80% steepness (depending on surface geology and landform). For example, Tyee Core formations are very susceptible to debris flows generally due to steep slopes, shallow low-cohesion soils, with an impermeable layer beneath. Lands with moderate hazard were found on slopes 50-70%. In addition, concave shaped landforms with large drainage areas were most frequently associated with landslides.

Robison et al. (1999) determined that forest cover and time since last timber harvest also influenced landslide occurrence, with lands 0-10 years post-harvest being most susceptible to landslides. However, forest stand age did not appear to affect the size of landslides.

Further, road-associated landslides were found to be four times larger (volume of earth moved) than landslides not occurring near roads. Landslides associated with abandoned logging roads ("legacy" roads) were smaller in size than those associated with active logging roads. Roads where drainage water was diverted (e.g., culvert or other relief structure), had higher landslide occurrences if the water exited on fill slopes. Roads carved out of slopes often deposit excavated fill on the downslope edge of the road, further influencing landslide hazards.

Rain-induced landslides are also thought to be more frequent during La Niña years, when the Pacific Northwest experiences increased storminess, increased precipitation and more days with measurable precipitation (UO 2012; NOAA 2002).

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Exhibit 26

News and Research Communications

13-year Cascadia study complete – and earthquake risk looms large

08/01/2012

CORVALLIS, Ore. – A comprehensive analysis of the Cascadia Subduction Zone off the Pacific Northwest coast confirms that the region has had numerous earthquakes over the past 10,000 years, and suggests that the southern Oregon coast may be most vulnerable based on recurrence frequency.

Written by researchers at Oregon State University, and published online by the U.S. Geological Survey, the study concludes that there is a 40 percent chance of a major earthquake in the Coos Bay, Ore., region during the next 50 years. And that earthquake could approach the intensity of the Tohoku quake that devastated Japan in March of 2011.

"The southern margin of Cascadia has a much higher recurrence level for major earthquakes than the northern end and, frankly, it is overdue for a rupture," said Chris Goldfinger, a professor in OSU's College of Earth, Ocean, and Atmospheric Sciences and lead author of the study. "That doesn't mean that an earthquake couldn't strike first along the northern half, from Newport, Ore., to Vancouver Island.

"But major earthquakes tend to strike more frequently along the southern end – every 240 years or so – and it has been longer than that since it last happened," Goldfinger added. "The probability for an earthquake on the southern part of the fault is more than double that of the northern end."

The publication of the peer-reviewed analysis may do more than raise awareness of earthquake hazards and risks, experts say. The actuarial table and history of earthquake strength and frequency may eventually lead to an update in the state's building codes.

"We are considering the work of Goldfinger, et al, in the update of the National Seismic Hazard Maps, which are the basis for seismic design provisions in building codes and other earthquake risk-mitigation measures," said Art Frankel, who has dual appointments with the U.S. Geological Survey and the University of Washington.

The Goldfinger-led study took four years to complete and is based on 13 years of research. At 184 pages, it is the most comprehensive overview ever written of the Cascadia Subduction Zone, a region off the Northwest coast where the Juan de Fuca tectonic plate is being subducted beneath the continent. Once thought to be a continuous fault line, Cascadia is now known to be at least partially segmented.

This segmentation is reflected in the region's earthquake history, Goldfinger noted.

"Over the past 10,000 years, there have been 19 earthquakes that extended along most of the margin, stretching from southern Vancouver Island to the Oregon-California border," Goldfinger noted. "These would typically be of a magnitude from about 8.7 to 9.2 – really huge earthquakes.

"We've also determined that there have been 22 additional earthquakes that involved just the southern end of the fault," he added. "We are assuming that these are slightly smaller – more like 8.0 – but not necessarily. They were still very large earthquakes that if they happened today could have a devastating impact."

The clock is ticking on when a major earthquake will next strike, said Jay Patton, an OSU doctoral student who is a co-author on the study.

"By the year 2060, if we have not had an earthquake, we will have exceeded 85 percent of all the known intervals of earthquake recurrence in 10,000 years," Patton said. "The interval between earthquakes ranges from a few decades to thousands of years. But we already have exceeded about three-fourths of them."

The last mega-earthquake to strike the Pacific Northwest occurred on Jan. 26, 1700. Researchers know this, Goldfinger said, because written records in Japan document how an ensuing tsunami destroyed that year's rice crop stored in warehouses.

How scientists document the earthquake history of the Cascadia Subduction Zone is fascinating. When a major offshore earthquake occurs, Goldfinger says, the disturbance causes mud and sand to begin streaming down the continental margins and into the undersea canyons. Coarse sediments called turbidites run out onto the abyssal plain; these sediments stand out distinctly from the fine particulate matter that accumulates on a regular basis between major tectonic events.

By dating the fine particles through carbon-14 analysis and other methods, Goldfinger and colleagues can estimate with a great deal of accuracy when major earthquakes have occurred over the past 10,000 years.

Going back further than 10,000 years has been difficult because the sea level used to be lower and West Coast rivers emptied directly into offshore canyons. Because of that, it is difficult to distinguish between storm debris and earthquake turbidites.

"The turbidite data matches up almost perfectly with the tsunami record that goes back about 3,500 years," Goldfinger said. "Tsunamis don't always leave a signature, but those that do through coastal subsidence or marsh deposits coincide quite well with the earthquake history."

With the likelihood of a major earthquake and possible tsunami looming, coastal leaders and residents face the unenviable task of how to prepare for such events. Patrick Corcoran, a hazards outreach specialist with OSU's Sea Grant Extension program, says West Coast residents need to align their behavior with this kind of research.

"Now that we understand our vulnerability to mega-quakes and tsunamis, we need to develop a culture that is prepared at a level commensurate with the risk," Corcoran said. "Unlike Japan, which has frequent earthquakes and thus is more culturally prepared for them, we in the Pacific Northwest have not had a mega-quake since European settlement. And since we have no culture of earthquakes, we have no culture of preparedness.

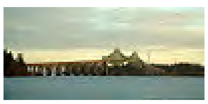
"The research, though, is compelling," he added. "It clearly shows that our region has a long history of these events, and the single most important thing we can do is begin 'expecting' a mega-quake, then we can't help but start preparing for it."

STORY BY:

Mark Floyd,
541-737-0788

SOURCE:
Chris Goldfinger, 541-737-5214

AVAILABLE PHOTO(S):
(click to download)



Coos Bay bridge

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Exhibit 27

The Oregon Resilience Plan

Reducing Risk and Improving Recovery for the Next Cascadia Earthquake and Tsunami

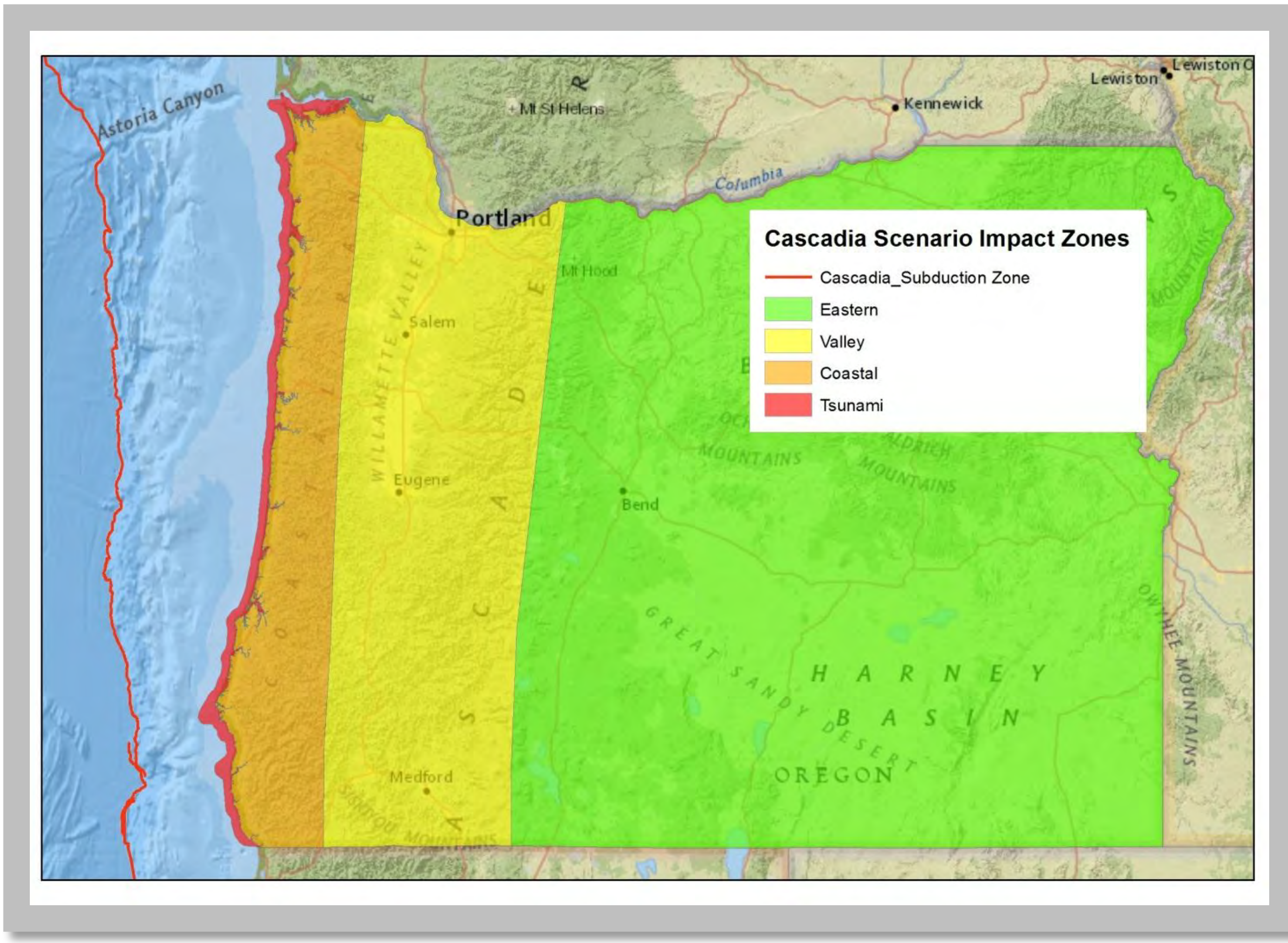
Report to the
77th Legislative Assembly

from
Oregon Seismic Safety Policy
Advisory Commission (OSSPAC)

Salem, Oregon
February 2013

Executive Summary

Very large earthquakes will occur in Oregon's future, and our state's infrastructure will remain poorly prepared to meet the threat unless we take action now to start building the necessary resilience. This is the central finding of the *Oregon Resilience Plan* requested by Oregon's 76th Legislative Assembly.



Impact zones for the magnitude 9.0 Cascadia earthquake scenario. Damage will be extreme in the Tsunami zone, heavy in the Coastal zone, moderate in the Valley zone, and light in the Eastern zone.

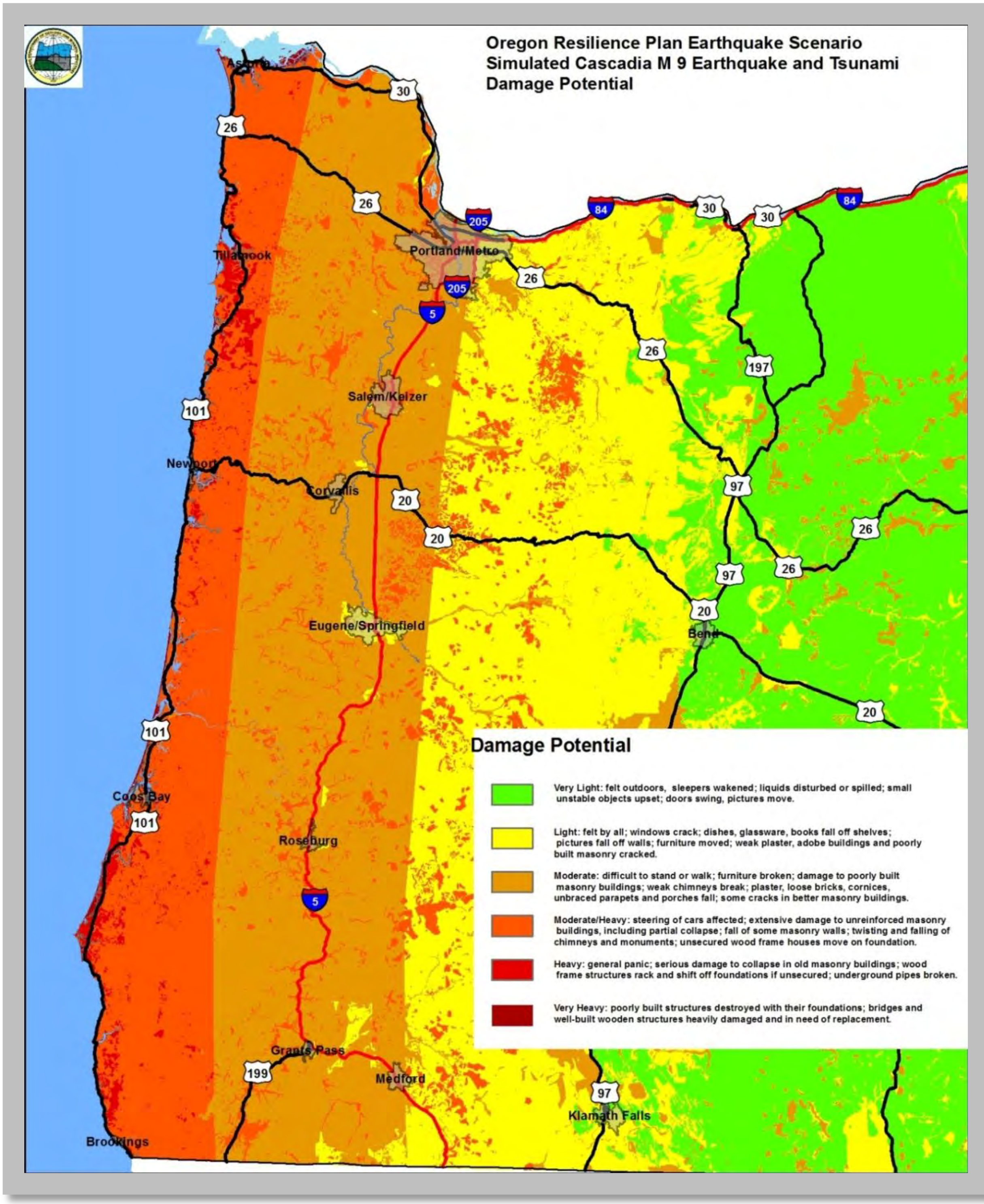


Figure 1.4: Simulated shaking for the magnitude 9.0 Cascadia scenario.

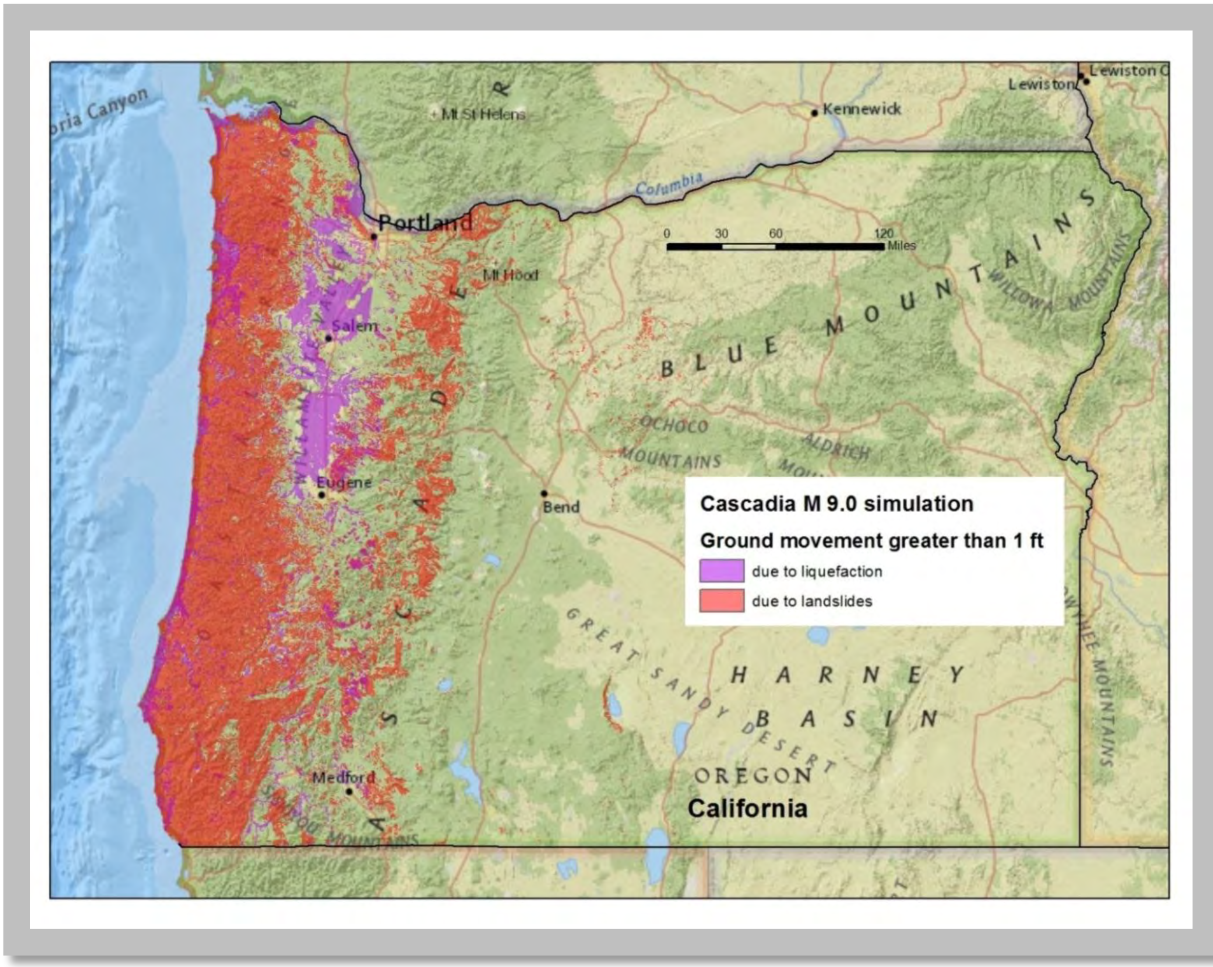


Figure 1.6: Ground failure and movement for the magnitude 9.0 Cascadia earthquake scenario. Colored areas could experience more than one foot of ground movement due to earthquake-induced landslides in steep areas and liquefaction failure in lowlands. Both forms of ground failure can cause severe damage.

The amount of tsunami inundation that would be experienced along the coast due to the scenario magnitude 9.0 earthquake is quite variable and depends on local topography. Large parts of many low-lying communities, such as Warrenton, Seaside, Rockaway Beach, and Neskowin (see Figure 1.7), will be inundated.

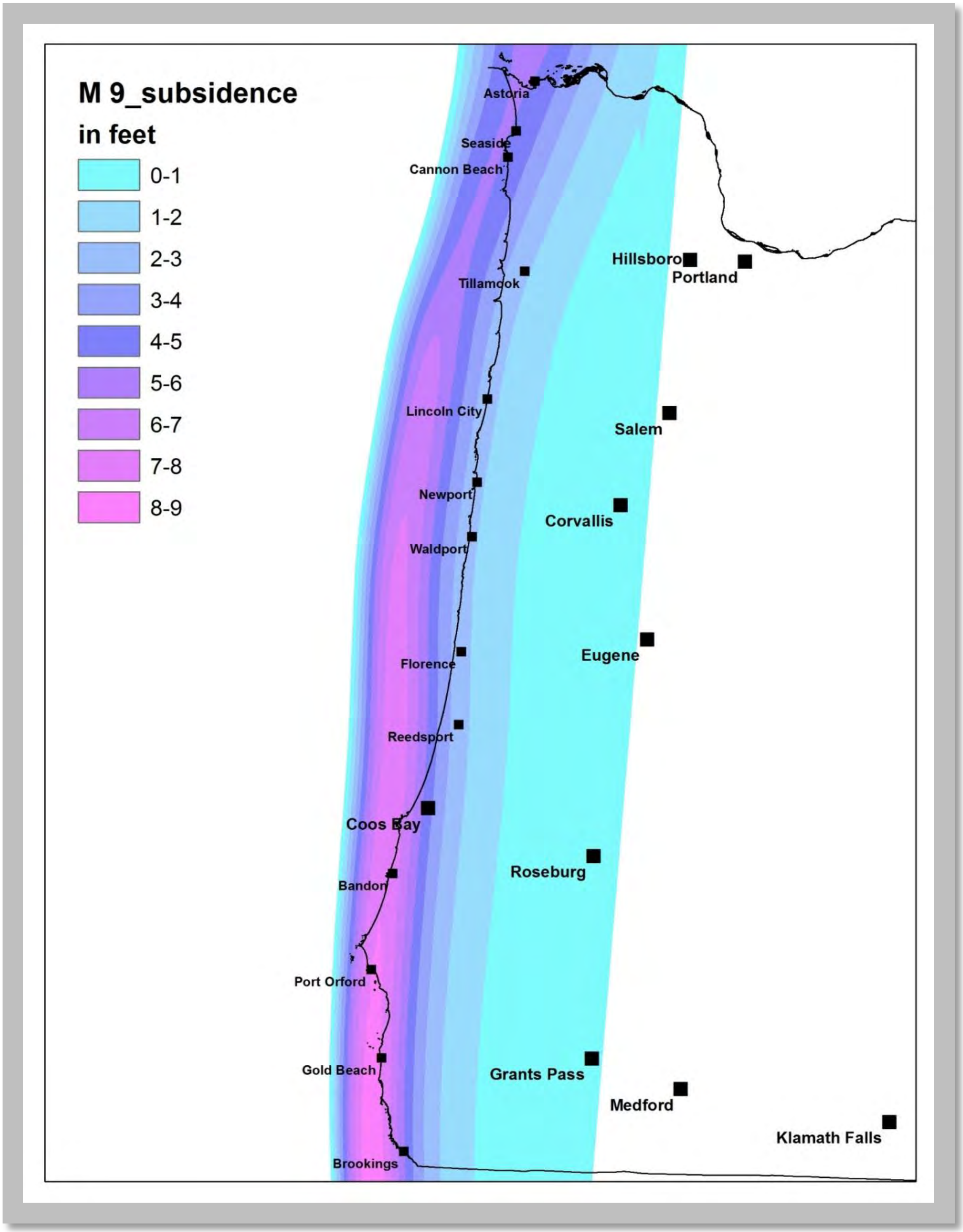


Figure 1.8: Estimated permanent land subsidence from the scenario magnitude 9.0 earthquake for the Oregon Coast. Subsidence would occur during the earthquake.

Exhibit 28

Industrial Energy Consumers of America (IECA)
The Energy Voice of Industrial Energy Consumers

EXCESSIVE LIQUIFIED NATURAL GAS (LNG) EXPORTS TO NFTA COUNTRIES ARE NOT IN THE PUBLIC INTEREST AND INCREASE NATURAL GAS AND ELECTRICITY PRICES TO CONSUMERS

JANUARY 30, 2019

OUTLINE

1. All DOE LNG export studies say exports increase natural gas prices.

2. The DOE has already approved volumes for export that are not in the public interest and plan to approve volumes equal to 52.8 billion cubic feet per day (Bcf/d). A volume equal to 71 percent of U.S. 2017 demand. The DOE has decided to let foreign countries determine the level of exports rather than limit export volumes that provide domestic consumers a safety net.

3. The DOE has never defined public interest under the NGA. All DOE studies confirm that LNG exports create winners and losers. The winners are the producers and exporters of natural gas. The losers are consumers and the economy.

4. DOE's approval of LNG exports for 20 to 30 years is a firm legal commitment to foreign countries LNG buyers. Where is the commitment to protect U.S. consumers?

5. The international LNG market is not a free market. It is for this reason that it is sound public policy to place limits on export volumes to levels that assure LNG exports will not increase domestic prices or impact reliability.

6. DOE has not addressed vital short- and long-term risks to consumers and the economy that are core issues in considering whether an LNG export application is consistent with the public interest.

    a. Failure to consider pipeline and storage capacity risks for existing and future constraints (and at peak demand), and their cost and reliability impacts.

    b. Failure to consider resulting higher marginal prices for natural gas and electricity consumers.

    c. Failure to address cumulative demand versus availability of natural gas resources.

    d. Failure to consider the uncertain nature of technically recoverable natural gas resources.

e. Failure to consider future political decisions such as limit to acreage available for drilling, regulations on water or hydraulic fracturing that could increase costs that must be recovered in higher prices of natural gas, thereby increasing consumer risk.

f. Failure to consider that the majority of producers of natural gas do not have a positive cash flow business, which means prices have to go up.

g. Failure to consider that gas producing companies are consistently overestimating well production, which leads to higher natural gas resources estimates than are available for the future.

h. Failure to consider that foreign consumers of U.S. LNG exports are receiving the benefits of using our infrastructure that is paid for by U.S. consumers, without paying for it. Their use of this infrastructure increases our costs.

7. The United States Trade and Development Agency (USTDA) is using federal tax dollars (or taxpayer money) to fund and promote LNG exports to importing countries.

COMMENTS

1. All DOE LNG export studies say exports increase natural gas prices.

The DOE released a study entitled, "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports"[1] which illustrates that LNG exports would substantially increase U.S. natural prices. On page 54 of the study it states that "for all the reference supply scenarios in the more likely range, natural gas prices could be from $5.00 to $6.50 per MMBtu in 2040. These mid-range scenarios have a combined probability of 47%." This is the highest probability the study gave any scenario. Since the Henry Hub price has most often been at roughly $3.00 MMBtu, the study confirms that natural gas prices could more than double causing domestic natural gas prices to rise to a level which would harm natural gas-dependent manufacturers and every homeowner. Consumers do not have an alternative. This is clearly not in the public interest.

The DOE released an earlier study in 2015 entitled, "The Macroeconomic Impact of Increasing LNG Exports"[2] and it provides the same conclusions, but also explains that the price of goods will rise and that the manufacturing sector will be damaged, along with competitiveness and the trade balance. On page 24 it states, "Henry Hub prices are higher than they would otherwise be as U.S. LNG exports increase because producers increasingly exploit reserves with higher extraction costs. Higher natural gas prices will erode consumers' purchasing power both directly and indirectly as the impact of higher domestic natural gas prices filters through the supply chains of other sectors causing the prices of other goods and services to rise. This will negatively

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[1] "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Export," U.S. Department of Energy (DOE), June 7, 2018, https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf.

[2] "The Macroeconomic Impact of Increasing LNG Exports," U.S. Department of Energy, October 29, 2015, https://www.energy.gov/fe/downloads/lng-export-studies

impact consumption with the energy intensive sectors being most affected. Changes in relative natural gas prices across countries will impact U.S. competitiveness. If energy prices in the United States rise relative to energy prices in the rest of the world, this raises production costs for U.S. firms relative to international competitors. This erosion in U.S. competitiveness will weigh on the U.S. trade balance. The tradable energy intensive sectors such as chemicals and steel will generally be most exposed to shifts in industrial competitiveness."

LNG exports also increase price volatility. In a recent Forbes article it states, "Truth be told, however, while U.S. gas prices have been their most volatile in around a decade over the past 10 weeks, more and more LNG exports to meet growing needs abroad would mean more ups and downs in domestic prices. We know that as the most bullish domestic demand factor, U.S. LNG exports will put a floor under our own market. LNG exports will increasingly become a baseload demand market and are not going to be easy to simply shut off if our own prices rise."[3]

In May 2018, the Commodity Futures Trading Commission (CFTC) released a report entitled, "Liquefied Natural Gas Developments and Market Impacts."[4] The report states, "Given the magnitude of U.S. exports, there is also the potential that domestic natural gas markets could become subject to global supply-demand dynamics with the potential for increased volatility." The report concludes that, "U.S. LNG export growth may put upward pressure on domestic (U.S.) natural gas prices and expose a heretofore relatively isolated North American market to global market dynamics."

2. **The DOE has already approved volumes for export that are not in the public interest and plan to approve volumes equal to 52.8 billion cubic feet per day (Bcf/d). A volume equal to 71 percent of U.S. 2017 demand. The DOE has decided to let foreign countries determine the level of exports rather than limit export volumes that provide domestic consumers a safety net.**

The DOE has already approved LNG export volumes equal to 30 percent of 2017 U.S. demand for shipment to NFTA countries, and volumes equal to 75 percent of 2017 U.S. demand to FTA countries, for periods of 20 to 30 years. NFTA countries are the largest global LNG consumers. Importantly, the DOE will consider the approval of 13 other applications to export in 2019.

Why markets should not be used to justify levels of specific LNG export applications volumes of LNG exports is illustrated with U.S. crude oil and gasoline prices. In the first half of 2018, because the U.S. crude oil price was connected to the global market, U.S. gasoline prices rose to the highest levels in over four years. Global demand from other countries dictated demand and price versus the U.S. supply and demand. The net result is that the U.S. consumer was NOT benefiting from our vast crude oil resources. This can and will happen to natural gas if our low natural gas prices are connected to the high price of global LNG markets. Today's low prices of

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[3] "U.S. Liquefied Natural Gas Hits Record Highs Again," Forbes, January 6, 2019, https://www.forbes.com/sites/judeclemente/2019/01/06/u-s-liquefied-natural-gas-hits-record-highs-again/#39f174a8141e

[4] "Liquefied Natural Gas Developments and Markets," U.S. Commodity Futures Trading Commission, https://www.cftc.gov/sites/default/files/2018-05/CFTC_LNG0518_3.pdf

natural gas are attributable to the fact that prices are determined by domestic supply and demand, not the global market.

This threat is not merely hypothetical, it happened in Australia. The Australian example shows that using markets to determine levels of LNG exports is not in the public interest. They are at least ten years ahead of the U.S. in exporting LNG. Australia has vast natural gas resources. Historically, the consumer prices have been around $3.00 MMBtu. Now, because of LNG exports, the Australian consumer pays the Asian LNG netback price. This means that the Australian consumer pays the high Asian LNG price, less transportation and liquefaction costs, which has resulted in Australian domestic consumer prices at $8, $9 and $10 MMBtu.

The Australian Competition and Consumer Commission started publication of LNG netback prices in order to boost price transparency.[5] The Australian consumer netback prices have increased from 7.27 Gj in 2017 to 10.69 Gj YTD 2018, a 47 percent increase. In approving LNG export terminals, the Australian government let markets determine the volume of exports, which has now directly caused disastrous impacts to consumers and the manufacturing sector as jobs continue to decrease.

3. **The DOE has never defined public interest under the NGA. All DOE studies confirm that LNG exports create winners and losers. The winners are the producers and exporters of natural gas. The losers are consumers and the economy.**

Congress raised the concern of exporting to NFTA countries in the NGA and delegated the responsibility of addressing LNG export applications to the DOE. Pursuant to section 3 of the NGA 15 U.S.C. 717b exports of natural gas, including LNG, must be authorized by the DOE. Under NGA section 3(a) 15 U.S.C. 717b(a) applications that seek authority to export natural gas to NFTA countries are presumed to be in the public interest unless, after opportunity for hearing, the DOE finds that the authorization would not be consistent with the public interest.

The problem is that DOE has never defined public interest according to the Government Accountability Office report of September 2014.[6] Despite the request of the Industrial Energy Consumers of America (IECA)[7], a trade association that represents manufacturing companies in Washington, DC, the DOE has refused to do so. Instead, the DOE has conducted studies that conclude that exports create net economic benefits for the U.S and have approved every application to export.

On June 21, 2018 it states in the Federal Register, "In granting each application, DOE concluded that exports of U.S. LNG will generate net economic benefits to the broader U.S. economy and will provide energy security and environmental benefits to the global community (including emerging economies presently reliant upon more carbon intensive fuels).[8]" As consumers, we

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[5] Australian Competition and Consumer Commission, October 2018,, https://www.lngworldnews.com/australian-watchdog-starts-lng-netback-price-publication/?utm_source=emark&utm_medium=email&utm_campaign=daily-update-lng-world-news-2018-10-05&uid=55872

[6] "Federal Approval Process for Liquefied Natural Gas Exports," U.S. Government Accountability Office (GAO), September 2014

[7] Industrial Energy Consumers of America homepage, www.ieca-us.org

[8] Federal Register/Vol. 83 No. 120/Thursday, June 21, 2018, page 28843

completely reject this definition. Instead, we support a Supreme Court definition of public interest. We believe that Congress had intended the public interest to be about the welfare of consumers (people) of natural gas.

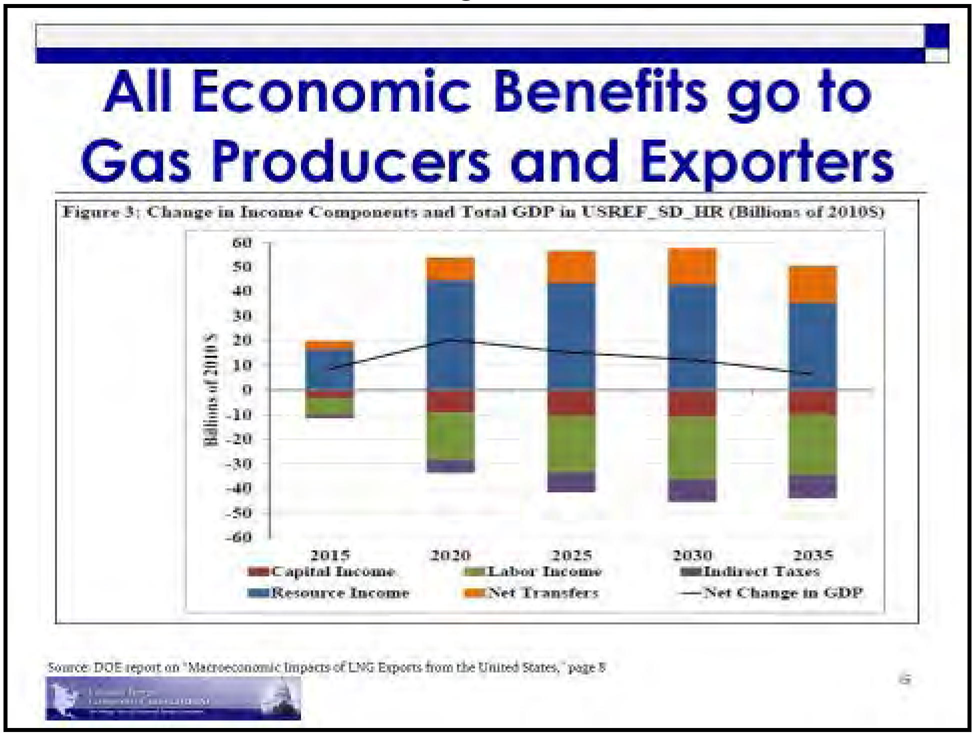
The U.S. Supreme Court has stated that “in order to give content and meaning to the words ‘public interest’ as used in the Federal Power and Natural Gas Acts, it is necessary to look to the purposes for which the Acts were adopted. In the case of the Power and Gas Acts it is clear that the principal purpose of those Acts was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices.”[9] Furthermore, the Supreme Court also stated that the “primary aim” of the NGA is “to protect consumers against exploitation at the hands of natural gas companies.”[10]

To this point, in 2012, the DOE released a report entitled “Macroeconomic Impacts of LNG Exports from the United States.”[11]. The report illustrates how natural gas companies exploit U.S. consumers by exporting LNG. Figure 1 below is from page 8 of the report. You will note that the only entities that benefit from LNG exports are a small sliver of the U.S. economy, namely producers and exporters of natural gas, while everyone else, while 323 million citizens are negatively impacted.

Page 7 of the report states that, “Expansion of LNG exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries.” Please also note that for volumes of 12 Bcf/d of LNG exports, it only contributes $20 billion to the economy in 2020 and decreases each year thereafter, while the negative impacts to consumers increases through 2030 before it levels off.

[9] NAACP v. Fed. Power Comm’n, 425 U.S. 662, 669-70 (1976).
[10] FPC v. Hope Gas Co., 320 U. S. 591, 610 (1944).
[11] “Macroeconomic Impacts of LNG Exports from the United States,” U.S. Department of Energy, December 3, 2012, https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

Figure 1



The vast majority of LNG is consumed by countries that do not have a free trade agreement with the U.S. It is inconsistent with the public interest to export LNG to NFTA countries.

Most U.S. shipped LNG is purchased by countries with which the U.S. does not have an FTA. From February 2016 to September 2018, 50.1 percent of U.S. LNG was shipped to NFTA countries.[12] These are countries that discriminate against U.S. manufacturing and farm products. Yet, we are shipping them a non-renewable vital resource for which every American consumer does not have an alternative. And, the DOE LNG export studies make clear that exporting LNG lowers the price of natural gas, especially to Asian countries. Page 8 of the 2015 DOE LNG report it states, "In every case, greater LNG exports raise domestic prices and lower prices internationally. The majority of the price movement (in absolute terms) occurs in Asia." Page 8 of this study also states that LNG exports creates declines in manufacturing and especially in energy-intensive industries, such as: chemicals, plastics, steel, aluminum, paper, refining, glass, cement, and food processing.

4. DOE's approval of LNG exports for 20 to 30 years is a firm legal commitment to foreign countries LNG buyers. Where is the commitment to protect U.S. consumers?

The Federal Register states, "As a preliminary matter, DOE/FE wishes to allay concerns about the security of existing (or future) non-FTA export authorizations. In this policy statement, DOE/FE affirms its commitment to all export authorizations issued under the NGA, including long-term authorizations approving the export of LNG to non-FTA countries. As indicated above, DOE/FE

[12] "LNG Reports," U.S. Department of Energy, https://www.energy.gov/fe/listings/lng-reports.

currently has issued 29 final non-FTA export authorizations, based on a thorough consideration of the public interest under section 3(a) of the NGA."[13]

> "However, DOE does not foresee a scenario where it would rescind one or more non-FTA authorizations. The United States government takes very seriously the investment-backed expectations of private parties subject to its regulatory jurisdiction. In particular, DOE understands the far-ranging economic investments and natural gas supply commitments associated with these authorizations over their full term—affecting both U.S. and global interests. DOE emphasizes that it remains committed to the durability and stability of the export authorizations it has granted under the NGA, as well as to supporting the approved export of U.S. natural gas around the world.[14]"

5. **The international LNG market is not a free market. It is for this reason that it is sound public policy to place limits on export volumes to levels that assure LNG exports will not increase domestic prices or impact reliability.**

Government limitations to LNG exports is in the public interest because natural gas is a non-renewable resource, U.S. consumers do not have an alternative, and the LNG market is not a free market. The LNG market buyers are countries – not companies or consumers (homeowners, farmers, businesses). The entities buying LNG are government backed state-owned enterprises (SOEs) and utilities who have automatic cost pass-through. Because they are countries, their responsibility is to ensure that sufficient supplies are purchased to keep the lights on at home and factories running. What this means is that, if necessary, they will pay any price, no matter how high, to supply their country's needs. In the future times when there are limits to supply capacity, this could pit countries against the U.S. consumer. Many countries who buy LNG also subsidize their manufacturing sector by not passing through the real costs of the purchased LNG, and regulate the price.

In December 2018, LNG World News report stated, "The major LNG buyers – CNOOC, CPC, JERA, KOGAS, PetroChina, Sinopec and Tokyo Gas – together account for more than 50 percent of the global LNG market."[15] Four out of six are Chinese SOEs.

> CNOOC (China National Offshore Oil Corporation, or CNOOC Group, is a major national oil company in China. It is the third-largest national oil company in the People's Republic of China, after CNPC and China Petrochemical Corporation.)

> CPC (China Petrochemical Corporation or Sinopec Group is the world's largest oil refining, gas and petrochemical conglomerate, administered by SASAC for the State Council of the People's Republic of China.)

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[13] FPC v. Hope Gas Co., 320 U. S. 591, 610 (1944).
[14] Federal Register/Vol. 83 No. 120/Thursday, June 21, 2018, page 28843
[15] "WoodMac: uncontracted demand by world's seven largest LNG buyers to quadruple," LNG World News, December 13, 2018, https://www.lngworldnews.com/woodmac-uncontracted-demand-by-worlds-seven-largest-lng-buyers-to-quadruple/?utm_source=emark&utm_medium=email&utm_campaign=daily-update-lng-world-news-2018-12-14&uid=55872

JERA (JERA Co., Inc.; Parent organizations: Tokyo Electric Power Company, Chubu Electric Power)

KOGAS (Korea Gas Corporation is a South Korean public natural gas company that was established by the Korean government in 1983. KOGAS has grown into the largest LNG-importing company in the world and operates four LNG regasification terminals and natural gas pipelines in South Korea.

PetroChina (PetroChina Company Limited is a Chinese oil and gas company and is the listed arm of state-owned China National Petroleum Corporation. It is China's second biggest oil producer.

Sinopec (China Petroleum & Chemical Corporation, or Sinopec, is a Chinese oil and gas enterprise based in Beijing, China.

Tokyo Gas (Tokyo Gas Co., Ltd., founded in 1885, is the primary provider of natural gas to the main cities of Tokyo, Kanagawa, Saitama, Chiba, Ibaraki, Tochigi, Gunma, Yamanashi, and Nagano. As of 2012, Tokyo Gas is the largest natural gas utility in Japan.)

6. **DOE has not addressed vital short- and long-term risks to consumers and the economy that are core issues in considering whether an LNG export application is consistent with the public interest.**

    a. **Failure to consider pipeline and storage capacity risks for existing and future constraints (and at peak demand), and their cost and reliability impacts.**

The DOE, nor the Federal Energy Regulatory Commission (FERC), has completed a study to consider existing and future limitations in natural gas pipeline and storage infrastructure capacity and maximum deliverability capacity needed to supply the U.S. market at peak demand and export LNG. Peak demand occurs in winter and summer months. All of the DOE LNG export studies used to justify approval of LNG applications to export assume that pipeline and storage capacity will be adequate, despite the fact that constraints already exist and the ability to build-out new pipeline capacity is threatened by multiple legal and public opposition headwinds.

The question of whether there is adequate pipeline capacity at peak demand is extremely important because the majority of LNG export buying countries are located in the Northern Hemisphere. This means that they have winter when we do. Their highest demand for buying U.S. LNG is when U.S. consumers have peak demand. The largest LNG importing countries are China, South Korea, Japan, and the EU.

LNG exports reduce the availability of pipeline capacity to domestic consumers. As more and more LNG export terminals are operational, the pipeline capacity used to feed these terminals are no longer available to U.S. consumer. And, there is evidence that LNG export terminals that need bank financing to construct the export terminal are required to have firm natural gas pipeline capacity available at all times to load the LNG export ships. If this is true, it means that these companies are not releasing their firm pipeline capacity to the market when they do not need it, thereby reducing the availability of pipeline capacity to U.S. consumers.

There are recent past winters where, for example, natural gas-fired power generation units and manufacturing companies have been unable to get the gas they need to operate due to pipeline capacity limitations. For power generators, this creates a reliability issue for electric consumers. For manufacturing, cutting back or shutting down can cost tens of millions of dollars per day per facility. LNG exports can compound these events.

b. Failure to consider resulting higher marginal prices for natural gas and electricity consumers.

The DOE LNG export studies used to justify approval of LNG export applications never considered its impact on the marginal price of natural gas and electricity. This is important any time of the year, but especially at peak summer and winter demand periods. The net effect of not doing so results in lower forecasted prices under macroeconomic LNG export scenarios.

c. Failure to address cumulative demand versus availability of natural gas resources.

In March 2018, IECA released a report which compares the U.S. Energy Information Administration's (EIA) AEO 2018 cumulative demand through 2050 to EIA's estimates of technically recoverable natural gas resources in the lower 48. Doing so illustrates that this demand would consume 69 percent of all resources. And, EIA has LNG exports peaking at only 14.5 Bcf/d. A very conservative forecast. While over time resources have been increasing, forecasted demand is outstripping new resources growth. IECA did the same analysis using EIA AEO 2017 demand. That analysis concluded that 57 percent of all resources would be consumed. We anticipate that AEO 2019 will show substantially higher and faster consumption of available resources.

d. Failure to consider the uncertain nature of technically recoverable natural gas resources.

It is also important to keep in mind that *technically available* resources do not mean that they are *economical* to produce. To this point, the natural gas industry's Potential Gas Committee's most recent report of July 2017[16] states that 58 percent of all natural gas resources are classified as either possible (new fields) or speculative (frontier fields), which adds more uncertainty that these resources may not produce low-cost natural gas. All DOE LNG export reports assume that this natural gas is economical to produce when no one really knows because no one has ever drilled a well in these new fields or frontier fields.

e. Failure to consider future political decisions such as limit to acreage available for drilling, regulations on water or hydraulic fracturing that could increase costs that must be recovered in higher prices of natural gas, thereby increasing consumer risk.

We have Presidential elections every four years that can change everything. As we have seen with some past Administrations, there were regulatory actions to limit access to federal lands for drilling and regulations to control drilling processes that increase the cost of production. A

[16] "Potential Supply of Natural Gas in the United States," Potential Gas Committee, December 31, 2016, http://pttc.mines.edu/PGC_Press_Conference_2017_07-19-2017_Final.pdf

new Administration could inflict all of these and more thereby increasing natural gas costs and prices. States have and will continue to take action to limit drilling. The DOE report used to justify LNG export applications do not consider these risks to consumers.

f. Failure to consider that the majority of producers of natural gas do not have a positive cash flow business which means prices have to go up.

In September 2018, the New York Times released a story entitled, "The Next Financial Crisis Lurks Underground." It states that the fracking industry is on shaky financial ground and have not proved they can make money. The 60 biggest exploration and production firms are not generating enough cash from their operations to cover their operating and capital expenses. In aggregate, from mid-2012 to mid-2017, they had negative free cash flow of $9 billion per quarter."[17] This is not sustainable long-term. Wall Street is concerned about the indebtedness of producers. Investors demand certain ROE's to continue to invest or lend money for drilling more wells. The fact that interest rates are also increasing puts further pressure on costs. Combined, this means that the price of natural gas must rise. DOE LNG studies do not address this fundamental issue.

g. Failure to consider that gas producing companies are consistently overestimating well production, which leads to higher natural gas resources estimates than are available for the future.

In January 2019, the Wall Street Journal released a story entitled, "Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast."[18] The story is equally telling because it provides hard facts that data analysis reveals thousands of locations are yielding less than their owners projected to investors, illusory picture of prospects. And, well production rates are used to forecast resource estimates used by the EIA and all others.

Thousands of shale wells drilled in the last five years are pumping less oil and gas than their owners forecast to investors, raising questions about the strength and profitability of the fracking boom that turned the U.S. into an oil superpower.

The Wall Street Journal compared the well-productivity estimates that top shale-oil companies gave investors to projections from third parties about how much oil and gas the wells are now on track to pump over their lives, based on public data of how they have performed to date.

[17] The Next Financial Crisis Lurks Underground, New York Times, September 1, 2018 https://www.nytimes.com/2018/09/01/opinion/the-next-financial-crisis-lurks-underground.html

[18] "Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast," Wall Street Journal, January 2, 2019, https://www.wsj.com/articles/frackings-secret-problemoil-wells-arent-producing-as-much-as-forecast-11546450162?emailToken=a83066aebe513ddd3dbf2884e46f03a2E51ZQs+dQXSXmYA/3dmjTGk92FGXvXm7YSvOKXP+yQkyys4Bhn0BJxZ8FcuVVg7cHl/sdfXzOdkDxa15Bqz5JNUhgx2GNxFLBsdMnCWf2IPz1zknNveMW3XGN8lad2VngvgXbxw79Pc8iAaMMoHQTQ%3D%3D&reflink=article_email_share

> "Two-thirds of projections made by the fracking companies between 2014 and 2017 in America's four hottest drilling regions appear to have been overly optimistic, according to the analysis of some 16,000 wells operated by 29 of the biggest producers in oil basins in Texas and North Dakota.
>
> "Collectively, the companies that made projections are on track to pump nearly 10% less oil and gas than they forecast for those areas, according to the analysis of data from Rystad Energy AS, an energy consulting firm. That is the equivalent of almost one billion barrels of oil and gas over 30 years, worth more than $30 billion at current prices. Some companies are off track by more than 50% in certain regions.
>
> "There are a number of practices that are almost inevitably going to lead to overestimates."

h. Failure to consider that foreign consumers of U.S. LNG exports are receiving the benefits of using our infrastructure that is paid for by U.S. consumers, without paying for it. Their use of this infrastructure increases our costs.

LNG exports use of U.S. infrastructure increasing the costs to all U.S. consumers. DOE has failed to consider these costs nor is this in the public interest.

7. The United States Trade and Development Agency (USTDA) is using federal tax dollars (or taxpayer money) to fund and promote LNG exports to importing countries.

We urge your support to stop the use of federal tax dollars to promote the export/import of U.S. LNG by the USTDA. This is corporate welfare and certainly not in the public interest. According to a news story entitled, "When it Comes to Natural Gas, US 'Open for Business"[19] the USTDA has funded 13 projects in 20-plus countries.

According to the story, USTDA has received more than 40 gas-related proposals this year, including a floating gas processing unit on China's east coast facility. Other spending included help to supply LNG to Morocco, Spain and Portugal, a gas-fired power plant in Egypt, and gas terminals in Honduras and Romania. If it is in the interest of those countries to import LNG, they should be willing and able to fund their own efforts.

In November of 2017, the USTDA, oil and natural gas industries, LNG export industries, and the U.S. Chamber of Commerce launched the "U.S. Infrastructure Exports Initiative."[20] We mention this only to reinforce the extremely high level of momentum behind the push to export unlimited volumes of LNG globally for which U.S. consumers are unaware and unprotected.

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[19] When I Comes to Natural Gas, US 'Open for Business', December 12, 2018, Associated Press, https://www.usnews.com/news/best-states/texas/articles/2018-12-12/when-it-comes-to-natural-gas-us-open-for-business

[20] "USTDA and U.S. Industry Launch U.S. Gas Infrastructure Exports Initiative," USTDA, November 17, 2017, https://ustda.gov/print/1501; "U.S. Gas Infrastructure Exports Initiative," https://www.ustda.gov/program/us-gas-infrastructure-exports-initiative; "General Funding Request Guidelines," https://www.ustda.gov/sites/default/files/Gas%20Proposal%20Guidelines.pdf

For all of the above reasons, we urge you to urgently act to protect the interest of the public and our economy. It is the shale gas revolution that has created the manufacturing renaissance. And, we are about to ship away our economic advantage to other countries.

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The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 3,700 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

Exhibit 29

Limitations of the Haynes Inlet sediment transport study

by

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Nov. 13, 2011

Limitations of the Haynes Inlet sediment transport study presented in Exhibit 4:

Chapters 10 and 11 of Exhibit 4 (entitled Jordan Cove Energy Project and Pacific Connector Gas Pipeline - Volume 2) present sediment transport calculations which purport to show that sediment transport impacts of the proposed dredging project in Haynes Inlet would have minimal impacts. However, close scrutiny of Exhibit 4 shows that there are serious deficiencies in the methodology employed in the sediment transport modeling. Consequently, the finding that there would only be limited impacts is lacking a solid foundation. The most serious flaws are outlined below:

1. Use of un-validated sediment transport model to establish background conditions

According to the Department of Environmental Quality, an "impacted" area is one that suffers a dredging-related turbidity level that is 10% or greater than background. Establishing background conditions is therefore a critical part of the process of defining impacted areas. The authors of the sediment transport study indicated that little data on ambient suspended sediment concentrations was available. The limited data available near the dredging site was collected in summer time whereas the dredging would occur in the fall and winter. As a consequence, the authors decided to use a model to establish background conditions. However, the model used was not validated with measurements from the study site.

Use of an un-validated sediment transport model to establish background conditions leads one to question the reliability of the project's findings. Using turbidity calculations generated by an un-validated model to establish background conditions is not reliable since sediment transport models are notoriously inaccurate especially when they have not been calibrated with data. Figure 1 (below) compares measured and modeled sediment transport (including bedload and

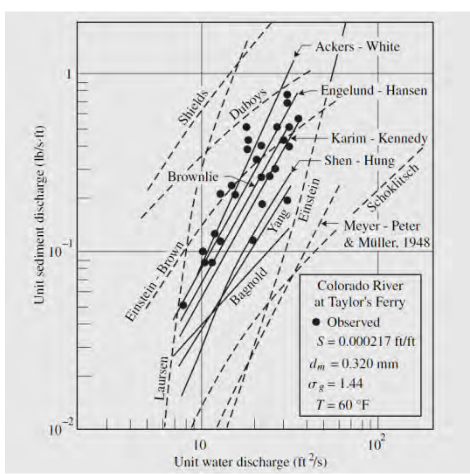

Figure 1. Plot comparing measured and calculated sediment discharge in the Colorado River as a function of water flow rate. The dashed and solid lines are calculated with various sediment transport models and the dots are measurements. The figure is from Erosion and Sedimentation, 2nd Edition, by Prof. Julien, Univ. of Colorado.

suspended sediment transport). It demonstrates the unreliable nature of sediment transport equations and models. If the authors of the Haynes Inlet sediment transport study are intent on using a model to establish ambient conditions, they should use the available data to validate their model. Model validation is a key part of peer-reviewed science and engineering work.

Use of an un-validated sediment transport model could result in an over-estimate of the background turbidity or suspended sediment concentration. This, in turn, would lead to an underestimate of the area impacted by the dredging project. For example, suppose the model calculated the background suspended sediment concentration to be 500 mg/liter (500 milligrams/liter), whereas the actual background concentration was 100 mg/liter. Based on the modeled result, the dredging-derived suspension could be as high as 50 mg/liter (10% of background) before the area was designated as impacted. However, based on the actual background condition, areas seeing dredging-derived suspension greater than 10 mg/liter should be defined as impacted. Using the actual background would clearly lead to an increase in the area that was designated as being "impacted". We can estimate the increase by extrapolating from Figure 10-5 of Exhibit 4 (reproduced below). Use of the true threshold (10 mg/liter or 2% on the y axis of Figure 10-5) would cause the linear extent of the impacted area to increase from about 350 ft to about 600 ft (for a 4 ft/s current).

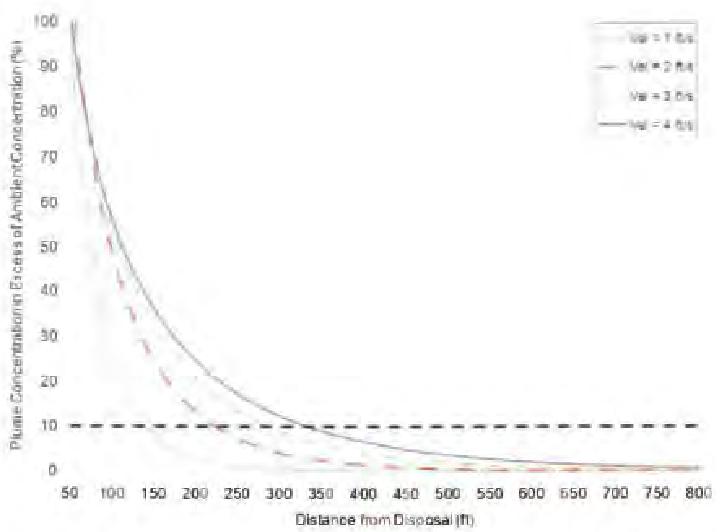

Figure 10-5. Suspended sediment concentration in excess of ambient concentration from numerical modeling results of trench stockpile placement activities in Haynes Inlet

Figure 2. Reproduction of Figure 10-5 of Exhibit 4.

2. Assumption of spatially uniform sediment size despite data indicating significant heterogeneity.

The authors of the Haynes Inlet sediment transport study conduct their modeling of background conditions and their modeling of dredging-related releases of sediment assuming that the sediment grain size is uniform throughout the study area (grain size is assumed to be 0.27 mm). However, the sediment characterization study conducted by GeoEngineers (August 2010) indicates that the sediments are significantly finer than this in large portions of the study area. GeoEngineers examined composite samples from three sections of the proposed pipeline route (DWWU-1, DWWU-2, DWWU-3, Figure 3). They found that, in section DWWU-1, the majority of the sediments were in the silt/clay size range with an overall median grain size of 0.04 to 0.05 mm (Figure 4, below).

Figure 3. Map of sections of the pipeline (DWWU-1, DWWU-2, DWWU-3) from Figure 1 of the sediment characterization study of GeoEngineers.

TABLE B-1

GRAIN SIZE ANALYSIS

PACIFIC CONNECTOR GAS PIPELINE PROJECT
HAYNES INLET, OREGON

Sample Identification	Sample Depth (ft)	Percent (%)		
		Gravel	Sand	Silt/Clay
In-Place Sediment Samples				
DMMU-1-Composite	0-9	1.2	48.4	50.4
DMMU-2-Composite	0-9	0.0	67.0	33.0
DMMU-3-Composite	0-9	0.7	86.2	13.1

W:\Boise\Projects\16\16724001\05\Finals\Sediment Characterization\[16724-001-05Tables.xlsx]B-1

Figure 4. Grain size data in the various sections of the pipeline from Table B-1 of the GeoEngineers Sediment Characterization Study.

The implications of assuming a uniform grain size when in fact the grain size is spatially variable are two-fold. First, the calculation of the background turbidity distribution at the study site would be inaccurate if the wrong grain size is assumed (even if the model itself was accurate). This is because sediment transport calculations are very sensitive to grain size. To illustrate this point, the average suspended sediment concentration was estimated for three different grain sizes (0.27, 0.10, and 0.05 mm) for a particular hydraulic condition (velocity = 3.3 ft/sec, depth = 10 ft, T = 50 F), similar to that assumed in Exhibit 4. The results are summarized in Table 1 below. Sediments of grain size 0.27 and 0.10 mm were considered to be non-cohesive. Suspended sediment concentrations were estimated based on the Einstein method (Julien 2010). In this approach, a near-bottom reference concentration is estimated based on a bedload transport calculation, and the Rouse Equation is used to determine the vertical distribution of suspended sediment. For the 0.05 mm sediment, a different calculation technique was used since the sediment would likely be cohesive. With cohesive sediment, resistance to motion is controlled by inter-particle forces instead of gravitational forces. The technique of Lavelle et al. (1984) of estimating a near-bottom reference concentration based on the sediment erosion rate and fall velocity was employed. Sediment erosion rate was estimated based on a linear erosion rate model in which erosion rate constant of 0.0032 kg m^{-2} s^{-1} Pa^{-1} was assumed (following Ravens and Gschwend 1999).

Grain size (mm)	Critical shear stress	Sediment fall velocity	Average suspended sediment concentration
[mm]	[Pa]	[mm/s]	[mg/liter]
0.27	0.2	30	10
0.10	0.1	9	3000
0.05	0.1	2	200

Table 1. Estimated suspended sediment concentrations for different grain sizes assuming an average velocity of 3.3 ft/sec and a depth of 10 ft.

The second implication of assuming the wrong grain size is that the modeling of the dredging-derived turbidity would be inaccurate. The time a given dredging-derived turbidity plume is suspended can be estimated based on the ratio of depth over the fall velocity. The fall velocity for 0.27 mm and 0.05 mm sediments is about 30 mm/s and 2 mm/s, respectively. Consequently, the finer sediment would be suspended for about 15 times as long and would be dispersed over 15 times the distance.

References:

Julien, P. Y. 2010. Erosion and Sedimentation, 2nd edition, Cambridge University Press.

Lavelle, J. W., Mofjeld, H. O., and Baker, E. T. (1984). ‘‘An in situ erosion rate for a fine-grained marine sediment.’’ *J. Geophys. Res.*, 89(C4): 6543–6552.

Ravens, T. M. and P.M. Gschwend. 1999. “Flume Measurements of Sediment Erodibility in Boston Harbor.” *J. of Hydraulic Engineering*. 125(10): 998-1005.

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Oct. 14, 2011

Andrew Stamp
Hearings Officer
c/o Coos County Planning Department
225 N. Adams Street
Coquille, Oregon 97423

At the request of Mark Chernaik, expert for Citizens Against LNG, I was asked to answer the following questions relating to the modeling of sedimentation impacts of pipeline construction in Haynes Inlet.

Q1. Could you describe your qualifications for answering the following questions? How many years have you studied hydrodynamic modeling of sedimentation that results from dredging activities? What peer-reviewed scientific publications on hydrodynamic modeling of sedimentation have you authored?

I have been modeling hydrodynamics and sediment transport in estuarine environments for 18 years. Some of the work that I have done tangentially addressed sediment transport impacts of dredging. My peer-review scientific publications that address hydrodynamics and sediment transport in coastal environments include:

Ravens, T., Jones B. M., Zhang, J., Arp, C. D., and J. A. Schmutz. Process-Based Coastal Erosion Modeling for Drew Point (North Slope, Alaska). *J. of Waterway, Port, Coastal, and Ocean Engineering* (in press).

Ravens, T. M., Thomas, R. C., Roberts, K. A., and P. H. Santschi. 2009. Causes of Salt Marsh Erosion in Galveston Bay, Texas. *J. of Coastal Research*, 25(2): 265-272.

Ravens, T. M. and M. Sindelar. 2008. Flume Test Section Length and Sediment Erodibility. *J. of Hydraulic Engineering*, 134(10): 1503-1506.

Rogers, A. and T. M. Ravens. 2008. Measurement of longshore sediment transport rates in the surf zone on Galveston Island, Texas. *J. of Coastal Research, 24(2): 62-73.*

Ravens, T. M. and R. C. Thomas. 2008. Ship wave-induced sedimentation of a tidal creek in Galveston Bay. *J. of Waterway, Port, Coastal, and Ocean Engineering.* 134(1): 21-29.

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Ravens, T. M., and K. I. Sitanggang. 2007. Numerical modeling and analysis of shoreline change on Galveston Island. *J. of Coastal Research,* 23(3): 699-710.

Ravens, T. M. 2007. Comparison of two techniques to measure sediment erodibility in the Fox River, Wisconsin. *J. of Hydraulic Engineering*, 133(1): 111-115.

Ravens, T. M., and R. A. Jepsen. 2006. CFD analysis of flow in a straight flume for sediment erodibility testing. *J. of Waterway, Port, Coastal, and Ocean Engineering*, 132(6): 457-461.

Ravens, T. M., and P. M. Gschwend. 1999. Flume measurements of sediment erodibility in Boston Harbor. *J. Hydraulic Engineering* 125(10): 998-1005.

Ravens, T. M., Madsen, O. S., Signell, R. P., Adams, E. E., and P. M. Gschwend. 1998. Hydrodynamic forcing and sediment quality in Boston Harbor. *Journal of Waterway, Port, Coastal, and Ocean Engineering.* 124(1): 40-42.

I would also point out that I am a regular reviewer of peer-reviewed Journals that address hydrodynamics and sediment transport including ASCE's Journal of Hydraulic Engineering, ASCE's Journal of Waterway, Port, Coastal and Ocean Engineering, Limnology and Oceanography, etc.

I earned my Ph.D. in Civil and Environmental Engineering from MIT. I have been tenured and promoted at both Texas A&M University and the University of Alaska.

Q2. What documents have you examined about the hydrodynamic modeling of sedimentation related to dredging in Haynes Inlet in Coos Bay?

1. Haynes Inlet – Trenched Sediment Transport and Sedimentation, dated 2011-09-21

2. Letter from Vladimir Shepsis, dated 2011-10-10

3. Report of Mark Chernaik, dated 2011-10-10 (see last section)

Q3. Could you please describe what "source terms" are in hydrodynamic modeling of sedimentation? Why would the disclosure of these source terms be indispensable for evaluating the validity of predictions from hydrodynamic models of dredging impacts?

Dredging and trenching operations are notorious for generating unwanted suspended sediment concentrations and deposition. For example, the recent dredging of PCB-contaminated sediments from the Hudson River has released a huge amount of sediments and contaminants. The EPA estimates that 440 kg of PCB's (largely born by sediments) was released (see the

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Executive Summary of the EPA Phase 1 Evaluation Report, March 12 2010). Sediment transport modeling of dredging operations should generally include a sediment production term that accounts for the introduction of suspended sediment into the water column. Data such as that cited in the report by Mark Chernaik (Exhibit 7) – showing the mass rate of sediment introduction due to clam shell dredging – should be used to assess the sediment transport impacts of dredging operations. However, a close reading of the statement provided by Vladimir Shepsis indicates that such an accounting of the particle generation of the dredging operation was not undertaken.

Vladimir Shepsis states:

My analysis is limited to the question of whether flow velocities resulting from pipeline construction will cause an increase in suspended sediment concentration and deposition of sediments in Haynes Inlet.

Thus, his analysis does not address the fate and transport of particles generated by the dredging project. His modeling only calculates the changed velocities that would result following dredged material placement and the increase in suspended sediment transport due to the changed velocity and – presumably - the changed bottom morphology. Again, there is no explicit accounting of suspended particles generated by the dredging and placement operation.

Although his statements are ambiguous[a], Vladimir Shepsis implies that more particles are generated **following** placement of dredged materials than during the dredging and placement process. If this is true, it is not common knowledge among sediment transport specialists. He should provide data or references to back up this assertion.

In addition to the issues raised above, it is important to point out that the statement provided by Vladimir Shepsis does not provide sufficient information to enable a full review of his sediment transport assessment. The statement provides little or no data on the character of the sediments. For sediment transport specialists, data on particle grain size distribution and fall velocity are critical. Also, it is critical to know whether the sediments are cohesive (fine) or non-cohesive (sand/gravel). If the particles are cohesive, then it is important to know the erodibility of the sediments. All of this basic information is missing.

The statement of Vladimir Shepsis does indicate that there would in fact be some elevated suspended sediment concentrations associated with the trenching. Further, he states that those suspensions would disperse and effectively disappear. This is not credible. Small concentration of particles can lead to significant deposition over time.

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[a] The ambiguous statement by Vladimir Shepsis is provided below:

Results from our analysis on this project and many other projects indicate that turbidity during placement of dredged material on an open bottom of a water body … is significantly higher than that during the digging of the same material.

Taking this statement at face value, it would appear prudent to assess the turbidity generated "*during the placement of dredged material*". However, elsewhere in his statement (see quote at the beginning of this section), he implies that turbidity generated during dredging and placement is minor compared to that which is generated following placement.

Q4. Do any of the documents you examined about the hydrodynamic modeling of sedimentation related to dredging in in Haynes Inlet in Coos Bay reveal the source terms?

As stated above, a close reading of the statements indicate that there was no accounting of the generation of particles due to the dredging/trenching operation.

Thom M. Raven

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Exhibit 30

U.S. Department of
Homeland Security

United States
Coast Guard

Commanding Officer
United States Coast Guard
Sector Portland

6767 N. Basin Avenue
Portland, OR 97217
Phone: (503) 240-9307
Fax: (503) 240-9586

16611
July 1, 2008

Lauren O'Donnell
Director of Gas – Environmental & Engineering, PJ-11
Federal Energy Regulatory Commission
888 First Street, N.E., Room 62-45
Washington, DC 20426

WATERWAY SUITABILITY REPORT FOR THE JORDAN COVE ENERGY PROJECT

Dear Ms. O'Donnell:

This Waterway Suitability Report (WSR) fulfills the Coast Guard's commitment under the Interagency Agreement among the Federal Energy Regulatory Commission (FERC), the Research and Special Programs Administration (RSPA), and the Coast Guard for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities that was signed in February 2004. Under this agreement, our agencies work together to ensure that both land and maritime safety and security risks are addressed in a coordinated and comprehensive manner. In particular, the Coast Guard serves as a subject matter expert on maritime safety and security issues.

On June 11, 2008, the Coast Guard completed a review of the Waterway Suitability Assessment (WSA) for the Jordan Cove Energy Project (JCEP) that was submitted in September of 2007. This review was conducted following the guidance provided in Navigation and Vessel Inspection Circular (NVIC) 05-05 of June 14, 2005. The review focused on the navigation safety and maritime security risks posed by LNG marine traffic, and the measures needed to responsibly manage these risks. During the review, the Coast Guard consulted a variety of stakeholders including state and local emergency responders, marine pilots, towing industry representatives, members of the Ports and Waterways Safety Committee and the Area Maritime Security Committee.

Based upon this review, I have determined that Coos Bay is not currently suitable, but could be made suitable for the type and frequency of LNG marine traffic associated with this proposed project. Additional measures are necessary to responsibly manage the maritime safety and security risks. The specific measures, and the resources needed to implement them, where applicable, are described below and in a separate supplementary report which is being provided to you under the terms and conditions established for handling Sensitive Security Information (SSI). This supplemental report includes a copy of the Jordan Cove Waterway Suitability Assessment. This determination is preliminary as the NEPA analysis has not yet been completed.

The following is a list of specific risk mitigation measures that must be put into place to responsibly manage the safety and security risks of this project. Details of each measure, including adequate support infrastructure, will need further development in consultation with the Coast Guard and state and local agencies through the creation of an Emergency Response Plan as well as a Transit Management Plan that clearly spell out the roles, responsibilities, and specific procedures for the LNG vessel and all agencies responsible for security and safety during the operation.

Navigational Measures:

<u>LNG Tanker Size Limitations:</u> Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, the maximum size LNG tanker permitted to transit through the Port of Coos Bay is a spherical containment LNG carrier with the physical dimensions of a 148,000 m^3 class vessel. The ship dimensions used in the study reflect a length overall of 950 feet, beam of 150 feet and a loaded draft of 40 feet. The channel must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed. Consequently, prior to approving the transit of an LNG ship larger than 148,000 m^3, or any increase in the physical dimensions cited, additional simulator studies must be conducted in order to assure the sufficiency of the channel.

- <u>Safety/Security Zone:</u> A moving safety/security zone shall be established around the LNG vessel extending 500-yards around the vessel but ending at the shoreline. No vessel may enter the safety/security zone without first obtaining permission from the Coast Guard Captain of the Port (COTP). The expectation is that the COTP's Representative will work with the Pilots and patrol assets to control traffic, and will allow vessels to transit the Safety/Security zone based on a case-by-case assessment conducted on scene. Escort resources will be used to contact and control vessel movements such that the LNG Carrier is protected.

  While the vessel is moored at the facility there shall be a 150 yard security zone around the vessel, to include the entire terminal slip. In addition, while there is no LNG vessel moored, the security zone shall cover the entire terminal slip and extend 25-yards into the waterway.

  Resource Gap: Resources required to enforce the safety/security zone are discussed under Security Measures in the supplemental report.

- <u>Vessel Traffic Management:</u> Due to a narrow shipping channel, navigational hazards, and the proximity to populated areas, LNG vessels will be required to meet the following additional traffic management measures:
  - A Transit Management Plan must be developed in coordination with the Coos Bay Pilot Association, Escort Tug Operators, Security Assets and the Coast Guard prior to the first transit.
  - This plan must be submitted to the COTP no less than 6 months to initial vessel arrival, and followed by an annual review to ensure that it reflects the most current conditions and procedures.
  - For at least the first six months, all transits will be daylight only, unless approved in advance by the COTP.
  - The LNG Vessel must board Pilots at least 5 miles outside the sea buoy.
    - Overtaking or crossing the LNG tanker within the security zone is prohibited for the entire transit from the Coos Bay Sea Buoy to mooring the vessel at the LNG terminal.
  - Vessel transits and bar crossings will be coordinated so as to minimize conflicts with other deep draft vessels, recreational boaters, seasonal fisheries, and other Marine Events.
  - 24 hours prior to arrival, the Coast Guard, FBI, Coos Bay Pilot Association, Escort Tug Masters, and other Escort assets will meet to coordinate inbound and outbound transit details.

Resource Gaps: The Vessel Transit Management Plan must be approved by the COTP at least 60 days prior to the first vessel arrival.

- Vessel Traffic Information System /Vessel Traffic System: The Port of Coos Bay does not have the capacity to receive Automatic Identification System (AIS) signals. AIS receiving capability must be established and must have the capacity to be used by appropriate agencies, port authorities and ship husbandry companies. Additionally, the Port does not have any means for continuous monitoring the navigable waterway. In order to ensure vessel safety and security, a robust camera system capable of monitoring the entire transit route must be established. Due to weather concerns, these cameras must be equipped with the means to adequately monitor vessel traffic in wind, rain and fog conditions.

  Resource Gaps: AIS receiver and camera systems including necessary hardware, software, staffing and training. Camera system must have complete coverage of the entire transit route, capable of detecting vessel traffic in wind, rain, fog, and dark conditions. Equipment and access to data feed of video imagery must be provided to state and local emergency operations centers impacted by the project.

- Tug Escort and Docking Assist: Due to the confined channel and high wind conditions, each LNG Carrier must be escorted by two tractor tugs, which will join the vessel as soon as safe to do so. The primary tug will be tethered at the direction of the pilot. A third tractor tug is required to assist with turning and mooring. Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, vessels are limited to transiting during periods of high tide and 25 knot winds or less. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.

  All three tractor tugs must be at least 80 Ton Astern Bollard Pull or larger and equipped with Class 1 Fire Fighting equipment.

  Resource Gaps: Three 80 Bollard Ton Tractor Tugs with Class 1 Fire Fighting capability.

- Navigational Aids:
  - Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, four aids to navigation must be added and eight aids to navigation relocated on the waterway (pg. 12-17).
  - Physical Oceanographic Real-Time System (PORTS) must be contracted with NOAA to provide real time river level, current and weather data.

- LNG Carrier familiarization training for Pilots and Tug Operators: Prior to the arrival of the first vessel, simulator training must be provided for pilots and tug operators identified as having responsibility for LNG traffic.

Safety Measures:

Emergency Response Planning: Regional emergency response planning is limited in the region. Emergency response planning resources will need to be augmented to adequately develop emergency response procedures and protocols as well as continuously update those plans as conditions change.

Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Vessel and Facility Inspections: LNG tankers and facilities are subject to (at a minimum) annual Coast Guard inspections to ensure compliance with federal and international safety, security and pollution regulations. In addition, LNG vessels and facilities are typically required to undergo a pre-arrival inspection, and transfer monitor.

  Resource Gap: Additional Coast Guard Facility and Vessel Inspectors.

- Shore-Side Fire-Fighting: Firefighting capability is limited in the area surrounding the proposed LNG terminal. Shore side firefighting resources and training will need to be augmented in order to provide basic protection services to the facility as well as the surrounding communities along the transit route.

  Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- In-Transit Fire-Fighting: Firefighting capability is limited along the entire transit route for proposed LNG vessels.

  Resource Gap: A plan must be developed for managing underway firefighting, including provisions for command and control of tactical fire fighting decisions as well as financial arrangements for provision of mutual aid and identification of suitable locations for conducting fire fighting operations along the transit route. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

  Public Notification System and Procedures: Adequate means to notify the public along the transit route, including ongoing public education campaigns, emergency notification systems, and adequate drills and training are required. Education programs must be tailored to meet the various needs of all waterway users, including commercial and recreational boaters, local businesses, local residents, and tourists.

  Resource Gap: A comprehensive notification system, including the deployment of associate equipment and training, must be developed. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Gas Detection Capability: No gas detection capability exists at the Port of Coos Bay, along the transit route and at the site of the proposed facility. Emergency response personnel require appropriate gas detection equipment, maintenance, and training. Additionally, the use of fixed detection equipment will ensure accurate and expedited gas detection in the event of a large scale LNG release. The installation of these detectors at strategic points along the waterway must be developed.

Resource Gap: Gas Detectors, appropriate training, and maintenance infrastructure. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

Security Measures:

- Security Boardings, Waterway Monitoring, and Vessel Escorts: Extensive security measures will be required to provide adequate protection for LNG vessels in transit to and while moored at the facility. The details of these measures are SSI, and are outlined in a separate supplementary report.

- Facility Security Measures: LNG facilities are subject to the security regulations outlined in 33 CFR 105, and are required to submit a Facility Security Plan (FSP) for Coast Guard approval, and undergo (at a minimum) an annual Coast Guard security inspection. The facility shall also develop a plan to provide for appropriate security measures from the start of construction through implementation of the Coast Guard approved FSP.

- Sandia Study: The WSA proposes the potential to receive vessels with up to 217,000 m^3 cargo capacity. The Sandia Report is based on consequences of LNG breaches, spills and hazards associated with LNG vessels having a cargo capacity no greater than 148,000 m^3 and spill volumes of 12,500 m^3. There remains some question as to the size of hazard zones for accidental and intentional discharges and the potential increased risk to public safety from LNG spills on water for larger vessels. Based on these existing uncertainties, Jordan Cove must either complete a site-specific analysis for the largest sized LNG vessel or limit arrivals to vessels with a cargo capacity no greater than 148,000 m^3 until additional analysis addressing vessels with higher cargo capacities is completed. However, this requirement is contingent on the requirement for US Coast Guard approval to receive LNG tankers larger than 148,000 m^3.

In the absence of the measures described in this letter and the resources necessary to implement them or changes in Coast Guard policy upon which the resource decisions are based, Coos Bay would be considered unsuitable for the LNG marine traffic associated with the Jordan Cove LNG Terminal. The applicant shall be required to submit an annual update to the Waterway Suitability Assessment to the Coast Guard which shall be revalidated by the COTP and AMSC. For further information, please contact Mr. Russ Berg of Coast Guard Sector Portland at (503) 240-9374.

Sincerely,

F. G. Myer
Captain, U.S. Coast Guard
Captain of the Port
Federal Maritime Security Coordinator

Copy: Thirteenth Coast Guard District (dp)
Coast Guard Pacific Area (Pp)
Commandant, Coast Guard Headquarter (CG-52), (CG-522), (CG-544)
Maintenance and Logistics Command Pacific (Sm)

Exhibit 31

COOS BAY HARBOR SAFETY PLAN

Coos Bay Harbor
Safety Committee

February 2018

TABLE OF CONTENT

1. Executive Summary

1.1 Introduction

The Coos Bay Harbor Safety Committee (CBHSC) is a volunteer committee comprised of industry stakeholders; local, state and federal agencies; and waterway user groups to help improve local coordination and leadership within the harbor. The committee was created under the recommendation of the Interagency Committee for the Maritime Transportation System (ICMTS) and the MTS National Advisory Council (MRSNAC) which were created following a report to Congress from the Maritime Transportation System (MTS) Task Force in September of 1999.

The purpose of the CBHSC is to recommend actions to improve the safety, security, mobility and environmental protection of Coos Bay and its waterways through:

- Effective communication and coordination between stakeholders
- Alignment with local, state and federal laws and regulations
- Identification and mitigation of hazards to navigational safety
- Collaboration with governmental agencies to improve and promote maritime and environmental safety within the committee's area of responsibility.

The Coos Bay Harbor Safety Committee (CBHSC) is an open forum comprised of public and private stakeholders in Oregon with vital interests in assuring safe navigation to protect the environment, property, and personnel on the waterways within the Coos Bay Region.

The CBHSC stakeholders accomplish the mission by adopting or developing appropriate standards and guidelines that address environmental and operational elements of maritime operations unique to the Coos Bay Region.

The CBHSC provides an inclusive, cooperative and equitable venue for addressing waterways issues to ensure the continuation and improvement of prudent management practices for our local waterways. Throughout the process, the CBHSC strives to ensure reliable and efficient marine transportation.

The CBHSC Charter is included in this plan under Appendix A.

1.2 The Harbor Safety Plan.

The plan has been adopted by Coos Bay in an effort to maintain and promote safety among all of the harbors users and create a platform for communication and collaboration. Guidance in setting up this Harbor Safety Committee and in developing this plan was taken from the US Coast Guard Navigation Circular (NVIC) 1-00; by attending other harbor safety committee meetings and from existing harbor safety plans from the states of Washington and California. The CBHSC's area of responsibility begins at the seaward approaches into Coos Bay and continues into the bay, and includes navigable tributaries within the bay.

1.2.1 Plan Implementation

The Coos Bay Harbor Safety Plan (CBHSP) is intended to complement existing regulations by advising the mariner of unique conditions and requirements that may be encountered in the region by providing standards of care and protocols developed by local experts. The CBHSP will be implemented through consensus agreement and cooperation from industry members, state and federal agencies, pilots and the Port of Coos Bay to follow the plan to the fullest extent possible barring any unforeseen circumstance that may warrant a change. The CBHSP is not intended to replace the good judgment of a ship's master in the safe operation of his/her vessel.

1.2.2 Plan Maintenance

The CBHS Committee will review the Harbor Safety Plan on an annual basis to ensure all information is up to date. Recommendations may be made to incorporate new information or additional standards of care at any regular meeting of the CBHS Committee. Plan updates are included in Appendix L and recommendations in Appendix I.

1.3 Harbor Safety Committee

The Committee General membership is responsible for providing recommendations, direction, and support within the committee's area of responsibility.

1.3.1 Chair:

The seven (7) member Board is made up of individuals representing the following waterway users.

1. Coos Bay Pilot Association
2. Stevedoring Company
3. Marine Terminal Operator, lower bay
4. Marine Terminal Operator, upper bay
5. International Oregon Port of Coos Bay
6. Fishing Representative
7. Public Representative

Officers are nominated and elected by a vote of a simple majority of a quorum of the Managing Board. Candidates for Officers are selected from the membership of the Managing Board.
Officer Positions include Chair, Vice Chair, and Secretary.

1.3.2 Members:

Members consist of individuals from companies, organizations, state and federal agencies as defined in the Charter.

Names and contact information can be obtained by emailing the Coos Bay Harbor Safety Committee at Coosbayharborsafety@gmail.com.

2 General Information

2.1 Geographical Boundaries

The Committees geographic region of responsibility (in blue boxes) begins at the seaward approach into Coos Bay, continues into the Bay and includes navigable tributaries within the Bay.

FIGURE 1 - NOAA CHART COOS BAY AND CBHSC AREA OF RESPONSIBILITY

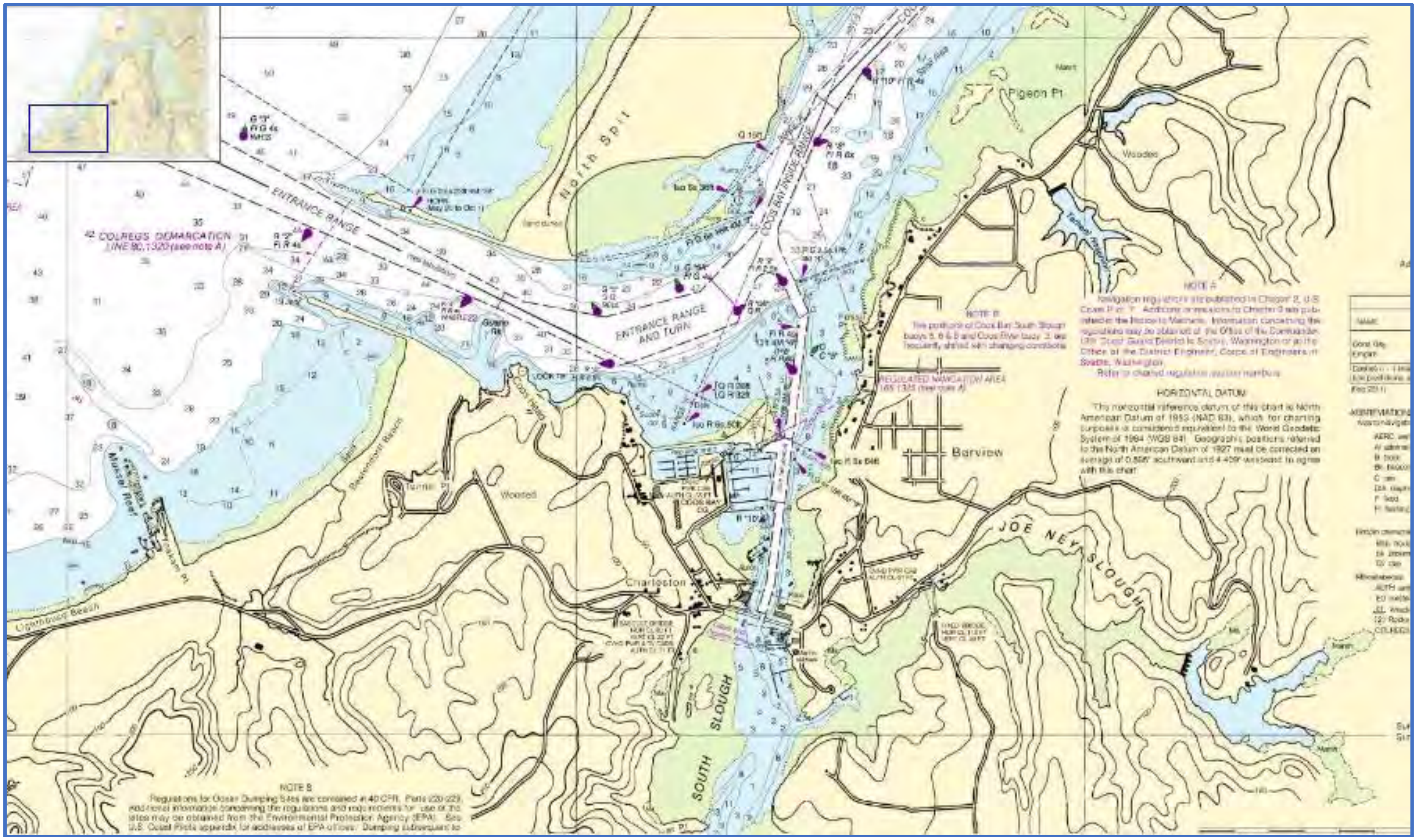


FIGURE 2 - SECTION OF CHART 18587 – ENTRANCE OF COOS BAY

This Section of Chart 18587 shows the Colreg Demarcation line and harbor entrance flanked by jetties with Charleston Channel and Boat Basin and South Slough to the south.

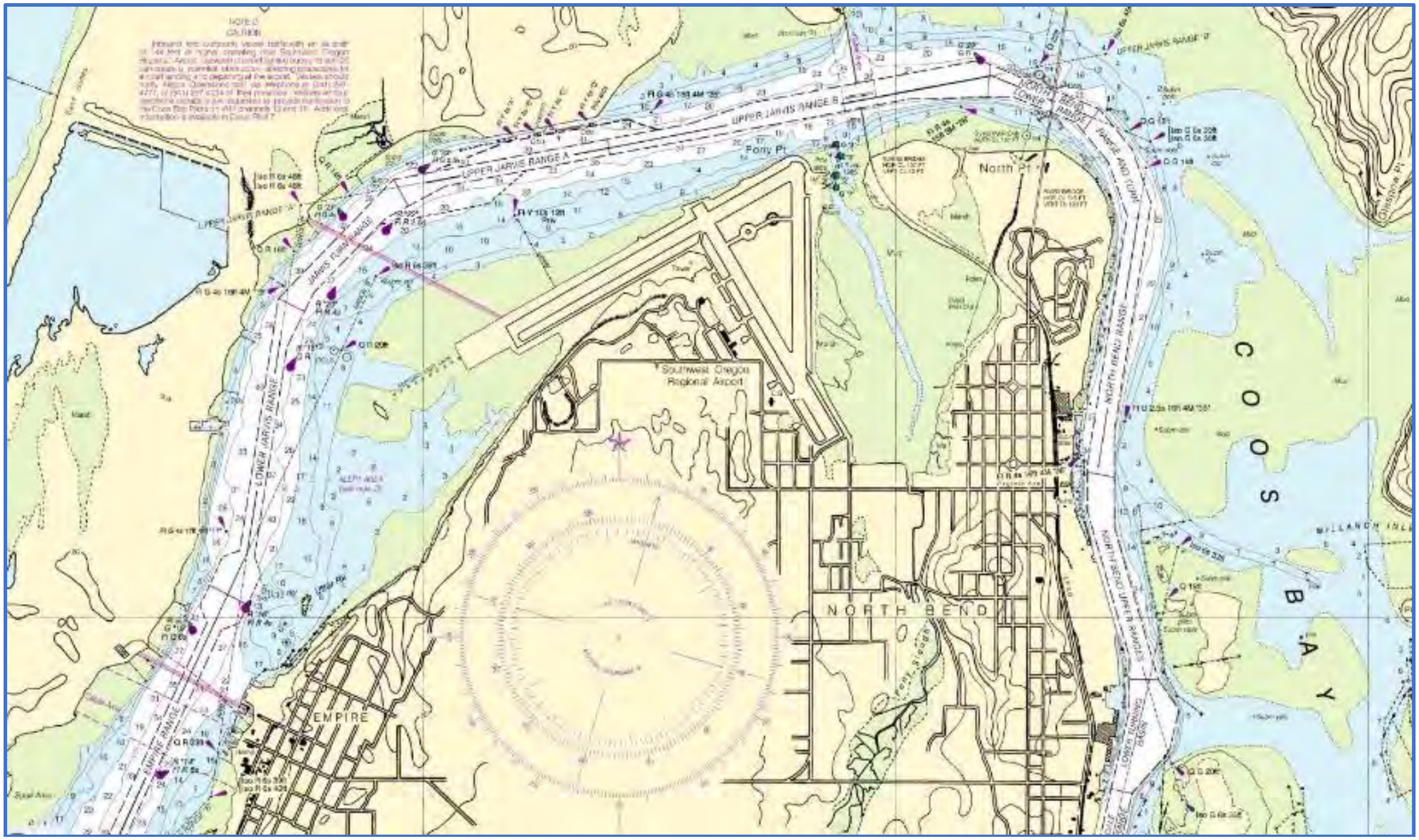


FIGURE 3 - SECTION OF CHART 18587- TOWNS OF EMPIRE AND NORTH BEND

Section of Chart 18587 showing the towns of Empire and North Bend and the airport in between.

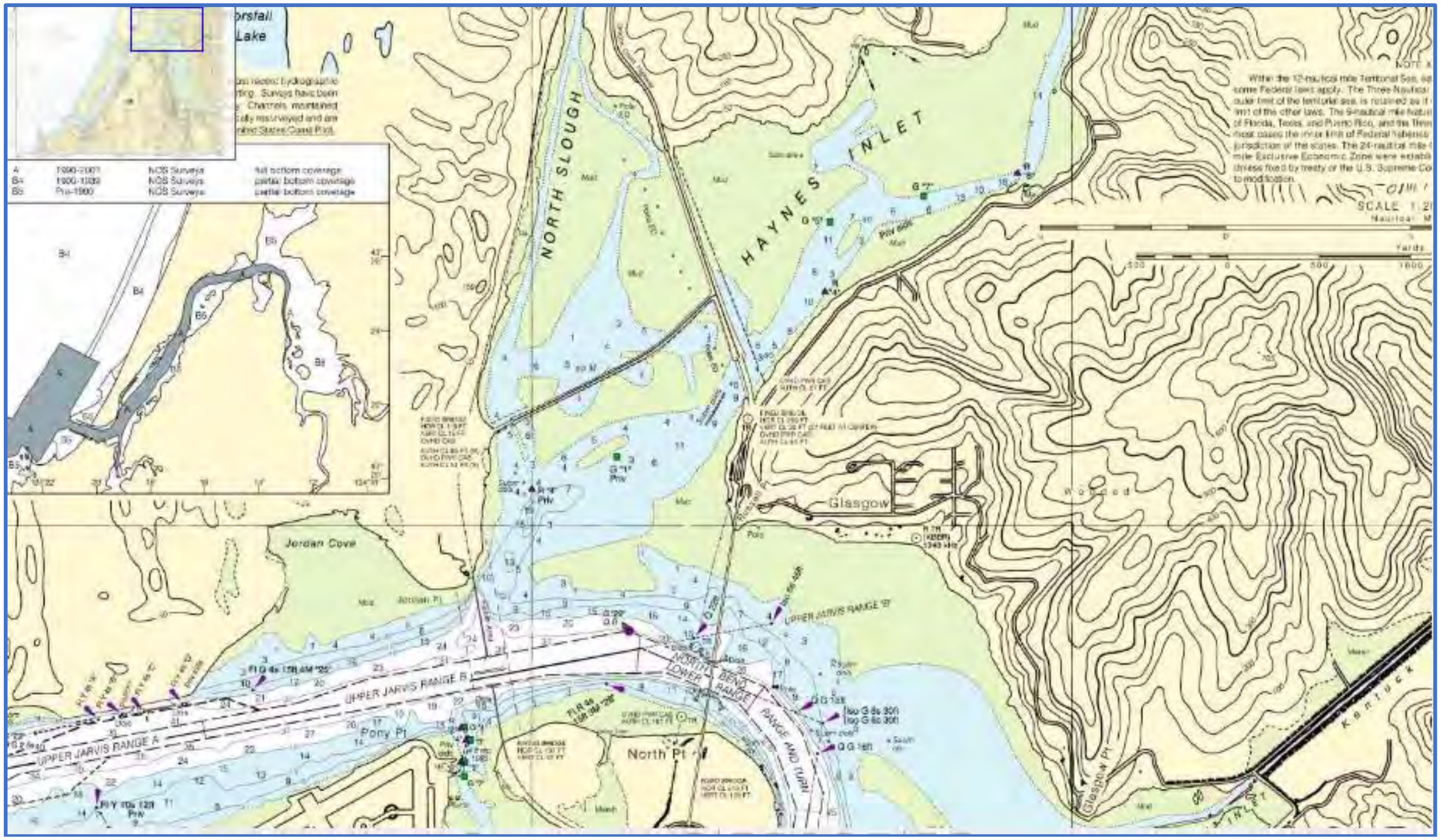


FIGURE 4 - SECTION OF CHART 18785 - JORDAN COVE TO HAYES INLET

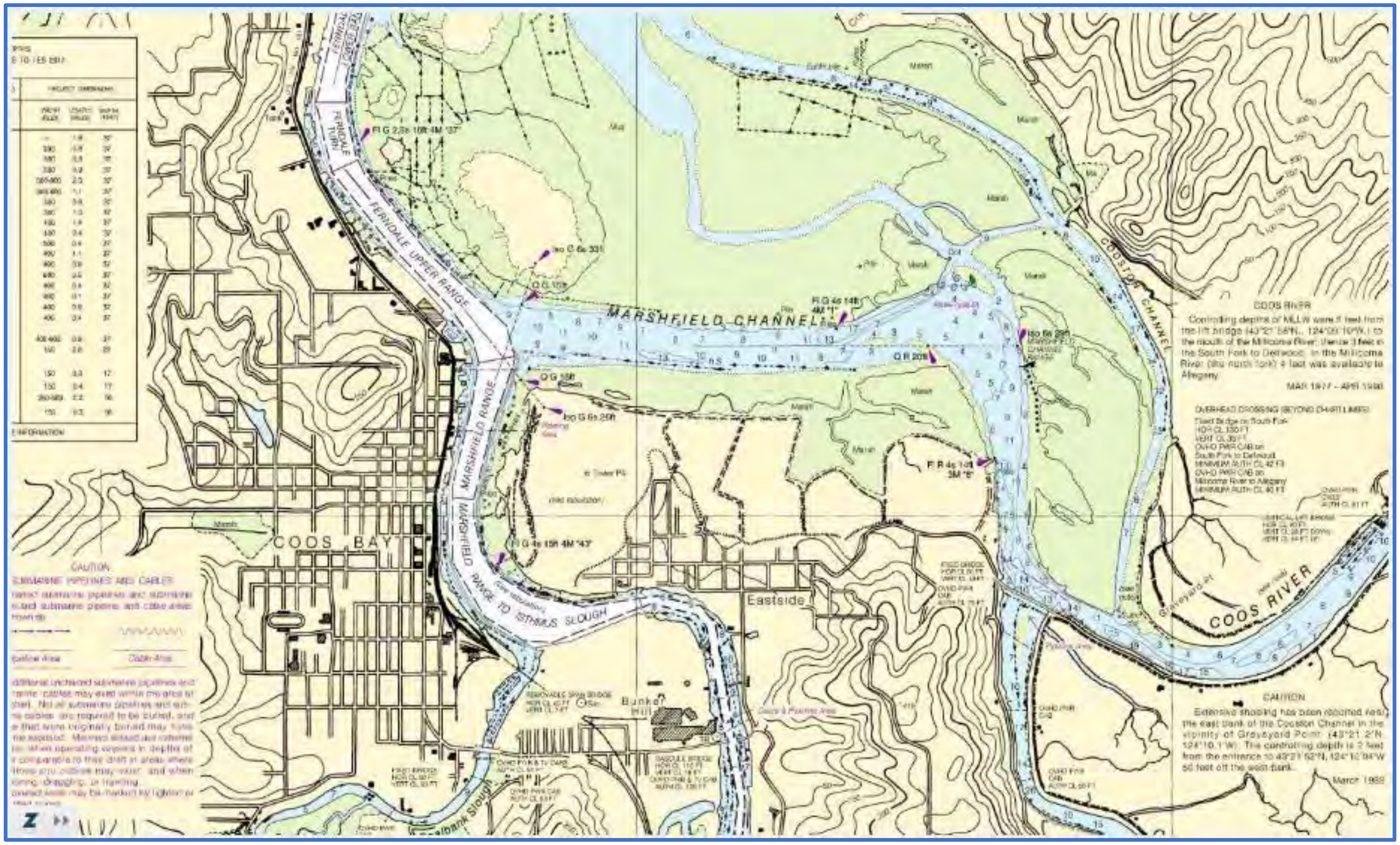


FIGURE 5 - SECTION OF CHART 18785 - TOWN OF COOS BAY, MARSHFIELD, COOSTON CHANNEL, ISTHMUS SLOUGH AND THE COOS RIVER

FIGURE 6 - SECTION OF CHART 18580 - OREGON COAST SHOWING COOS BAY

2.2 Economic and Historical Background

Coos Bay is the largest coastal harbor between San Francisco and Puget Sound, and Oregon's second busiest maritime port. The federally authorized and maintained deep-draft navigation channel is under the management and oversight of the US Army, Corps of Engineers. Manufactured forest products and wood fiber exported from the port's marine terminals continue to make it one of the leading wood products shipping centers of North America. The Port imports and exports logs and exports large quantities of wood chips which are used in making paper products and biomass fuels.

The port's vision is to promote the optimal use of Coos Bay's deep-water port for the enhancement of the economy and quality of life in the region.

Historically, wood products, commercial fishing, and shipping have been the mainstays of the Bay area's economy; more recently tourism has become an important segment. Though it has waned, the port is still one of the leading centers for the lumber and wood products industry. The area is also known for its 32 million pounds of seafood landed annually by crabbers (Dungeness crab), trollers and trawlers fish for chinook salmon, albacore tuna, and pink shrimp.

Oregon International Port of Coos Bay is designated a State Port; consequently, members of the Board of Commissioners are appointed by the Governor and confirmed by the Oregon Senate for 4-year terms. Commissioners must be residents of the Port District.

The Port Authority, the Oregon International Port of Coos Bay, is controlled by a Board of Port Commissioners and an Executive Director. Harbor regulations, under Oregon Revised Statute 777, are prescribed by the Port Commissioners and enforced by the Executive Director. The Port owns 700 acres of the property but they do not operate any of the maritime facilities with the exception of the Charleston Marina. The marina is located just inside the entrance to Coos Bay and is home to a fishing and recreational fleet of 400-500 boats.

3 Coos Bay

Thirty-three (33) miles north of Cape Blanco, Coos Bay is used as a harbor of refuge and can be entered at any time except in extreme weather. From the entrance, the bay extends northeast for 8 miles with widths of 0.3 to 1 mile, then bends southeast for about 4 miles to the mouth of Isthmus Slough. The dredged channel through the bay is bordered by marshland and intersected by several sloughs.

The entrance to Coos Bay is located at latitude 43° 22' North/Longitude 124 ° 22' West. The Coos Bay Sea Buoy is approximately 173 nautical miles/320 km south of the Columbia River, and 367 nautical miles/680 km north of the entrance to San Francisco Bay.

3.1 Prominent features

Coos Head is a good guide to the entrance. The sand dunes north toward Umpqua River are prominent. The entrance to the bay is protected by jetties. A light with a seasonal sound signal marks the north jetty. A lighted whistle buoy ((RW "K" MO (A) Whis)) is 1.8 miles west-north-west of the entrance. The channels are marked with lighted ranges, lights, buoys and day beacons. Although no longer lighted, Cape Arago Lighthouse is a prominent 44-foot white octagonal tower attached to a building on a rocky, partially wooded island close inshore, 2.5 miles north of the cape.

3.2 Routes

There is usually a current sweeping either north or south just off the jetties, and this current should be guarded against. The entrance ranges should be watched carefully until clear of all dangers. The south current is often encountered during the summer. With strong south winds during the winter, the current sometimes sets to the north.

Approaching from any direction in thick weather, great caution is essential. The currents are variable and uncertain. Velocities of 3 to 3.5 knots have been observed offshore between Blunts Reef and Swiftsure Bank, and greater velocities have been reported. The most favorable time for crossing the bar is on the last of the flood current, and occasionally it is passable only at this time.

3.3 Coos Bay Channel

Coos Bay's short 15-mile Federal navigation channel helps ensure that inbound and outbound cargoes move rapidly and efficiently through the harbor's marine terminals to domestic and international markets. Travel time from ocean to land is only 90 minutes.

3.3.1 Depths and Widths

A Federal Project provides for a 37-foot deep and nominal 300-foot-wide channel across the bar to the railroad swing bridge at Pony Point, and then is 400-foot-wide to the end of the navigation channel at a point 1.1 mile above the mouth of Isthmus Slough, and thence, 22 feet to Millington, 14.7 miles above the entrance to the bay. Turning basins at North Bend and Coos Bay have depths of 37 feet.

COOS BAY ,ISTHMUS SLOUGH AND CHARLESTON CHANNEL DEPTHS
TABULATED FROM SURVEYS BY THE CORPS OF ENGINEERS • SURVEYS TO NOV 2016

CONTROLLNG DEPTHS FROM SEAWARD IN FEET AT MEAN LOWER LOW WATER (MLLW)					PROJECT DIMENSIONS		
NAM£ 01' CHANN£L	OUTSIDE QUARTER	HALF OF CHANNEL	OUTSIDE OUAATER	DATE OF SUAIIEY	WIDTH (FEET)	IENGTH (MILES)	DEI'Tt1 (FEET)
ENTRANCE RANGE	39	39	40	816	—	1.9	37
ENTRANCE RANGE AND TURN	38	44	33	11·16	300	0.8	37
COOS BAY INSIDE RANGE	38	38	38	11-16	300	0.8	37
COOS BAY RANGE	37	37	36	1116	300	0.9	37
EMPIRE RANGE	3D	37	30	10-16	300·800	2.3	37
LOWER JARVIS RANGE	S4	38	21	1016	300-800	1.1	37
JARVIS TURN RANGE	37	41	34	1 16	300	0.6	37
UPPER JARVIS RANGE A	37	37	3S	1 16	300	1.0	37
UPPER JARVIS RANGE B	3S	37	36	1 16	400	1.4	37
NORTH BEND LOWER RANGE	36	39	36	1 16	400	0.4	37
RANGE AND TURN	34	39	38	10·16	500	0.4	37
NORTH BEND RANGE	33	38	35	10-16	400	1.1	37
NORTH BEND UPPER RANGES	35	38	37	1 16	400	0.8	37
LOWER TURNING BASIN	37	38	38	10-16	B00	0.5	37
FERNDALE LOWER RANGE	32	38	34	9 16	400	0.4	37
FERNDALE TURN	20	33	35	9·16	400	0.1	37
FERNDALE UPP£A RANGE	8	27	24	916	400	0.9	37
MARSHRELD RANGE	28	25	17	9·18	400	0.4	37
MARSHRELD RANGE TO ISTHMUS SLOUGH	19	17	25	9 18	400-600	0.9	37
ISTHMUS SLOUGH	19	20	19	4-85	150	2.0	22
CHARLESTON CHANNEL							
ENTRANCE	18	19	18	10·18	150	0.3	17
ENTRANCE TO BASIN	18	18	16	10-16	150	0.4	17
BASIN	15	15	16	10-16	250.000	0.2	16
BASIN TO BRIDGE	16	18	16	10·16	150	0.3	16

NOTE· CONSULT THE CORPS OF ENGINEERS FOR CHAHGES SUBSEOUENT TO THE ABOVE INFORMATION

FIGURE 7 - CHANNEL DEPTHS, 2016 SURVEY

3.3.2 Tidal Range

Tidal Ranges

- Mean 5.6 feet/1.7 meters
- Diurnal 7.3 feet/2.2 meters
- Maximum 12 feet/3.7 meters
- Tidal ebb to 3 knots

3.3.3 Dredging Plans

The USACE maintains the 15.2-mile federal navigation channel and the Charleston channel to the Bascule bridge, South Slough. Dredging for the federal projects is completed based on annual appropriations and critical needs. The Oregon International Port of Coos Bay holds and maintains a Unified dredging permit for 18 public and private terminals and marinas within the bay. This permit authorizes these facilities to fund and conduct dredging operations within their authorized dredge prism. Dredging operations can be conducted under the Unified permit during the authorized In-Water Work Period (IWWP) from October 1st to February 15th. An IWWP Variance may be requested and approved on a case-by-case basis.

3.3.4 Coos Bay Channel Modification Project

The Port of Coos Bay is proposing to deepen and widen the Federal navigation channel through a project that will expand the existing channel from -37 feet depth and a nominal 300 feet width to -45 feet depth and nominal 450 feet width from the channel entrance to river mile 8.2.

3.4 Charleston Channel

The channel is maintained 150 feet wide and 20 feet deep and starts upstream of Buoy 6A and ends at the Bascule Bride. The channel is mostly used by recreational boaters and the commercial fishing fleet.

3.5 Anchorage

Anchorage for small craft is available almost anywhere in the bay outside the dredged channels. However, there are no dedicated anchorages outside of Coos Bay or within the harbor for larger commercial vessels. The bottom conditions outside the harbor are sandy with moderate holding power. Inside the harbor within the channel, the bottom is sandstone mixed with sand/silt. While anchoring in the channel by deep draft vessels can be accomplished under certain circumstances at the Pilot's discretion, it is not frequently done.

Due to the rapid and severe onset of weather from the North Pacific Ocean, anchorage in the ocean outside of Coos Bay is reported not safe and is dangerous during the winter months. Like all unprotected areas along the Oregon coast, large swells and heavy winds characterize the area during the winter. These conditions can suddenly and unexpectedly besiege the unwary with catastrophic results. The prevailing direction of both swell and wind will drive disabled or improperly handled vessels onto the shore.

While desired, there are currently no designated anchorage areas off the coast or within the channel, primarily due to the grounding of the M/V New Carissa in 1999 off the coast of Coos Bay.

3.6 Layberths

There are no designated layberths, but vessels may request and coordinate the use of a private berth/docks with the facility in question.

3.7 Navigational Dangers

- Guano Rock, on the south side of the entrance channel and 280 yards northwest of Coos Head. It never uncovers even during extreme low tides.

- Submerged Jetties:
  - A submerged section of the north entrance jetty extends about 450 yards west of the visible jetty, and a submerged section of the south entrance jetty extends about 100 yards west of the visible jetty. Because of the submerged jetties, it is reported that there are breakers in these areas most of the time. Extreme care must be exercised at all times.
  - A submerged jetty extends 500 yards off the east shore of Coos Bay just inside the entrance, 0.8 miles northeast of Coos Head. In entering with a strong northwest wind, large vessels have difficulty in making the turn and may find themselves being set toward the submerged jetty.

- Coos Bay Rail Bridge: This is a swing bridge kept in the open position when no trains are crossing. Mariners should use extreme caution when passing through the bridge because of unpredictable changing winds, currents, and sea conditions reported in this area. The location of the Upper Jarvis ranges in relation to the bridge opening is offset 35 feet to the North, resulting in vessel passing closer to the center support of the bridge.

- Southwest Oregon Regional Airport: For safety reasons, the FAA limits the height of vessel transiting in front of the runway. Inbound and outbound vessel traffic near the Airport may affect procedures for aircraft landing and departing at the airport. Vessels with an air draft of 144 feet or greater present a potential obstruction to airspace that requires advisories be issued to aircraft by air traffic controllers, and in some cases, runway use may need to be restricted. See Special Navigational Conditions for more for more details.

- Crab Fishing Gear: Heavy concentrations of fishing gear may be expected off Coos Bay and along the coast between December 1 and August 15, from shore to about 30 fathoms. To reduce the destruction of fishing gear by vessels and to reduce the fouling of propellers and shafts by fishing gear, Washington Sea Grant, Washington State University Extension has coordinated an agreement between towboat operators and crab fishermen for the establishment of towboat lanes along the Pacific coast between San Francisco, California and Cape Flattery, Washington. Copies of the agreement showing fishing areas and towboat lanes may be obtained from Washington Sea Grant, Washington State University Extension, Box 88, South Bend, WA 98586; telephone 360–875–9331 and have been distributed to the towboat operators and the Dungeness crab fishery. This information can also be obtained on the Washington State University website:

https://wsg.washington.edu/wordpress/wp-content/uploads/Towlane-Chartlets-WA-OR-CA.pdf.

- However, despite the ongoing issue of crab gear being caught up in towboat propellers and towing gear, there are no designated tow boat lanes for the Coos Bay area during the crabbing season.

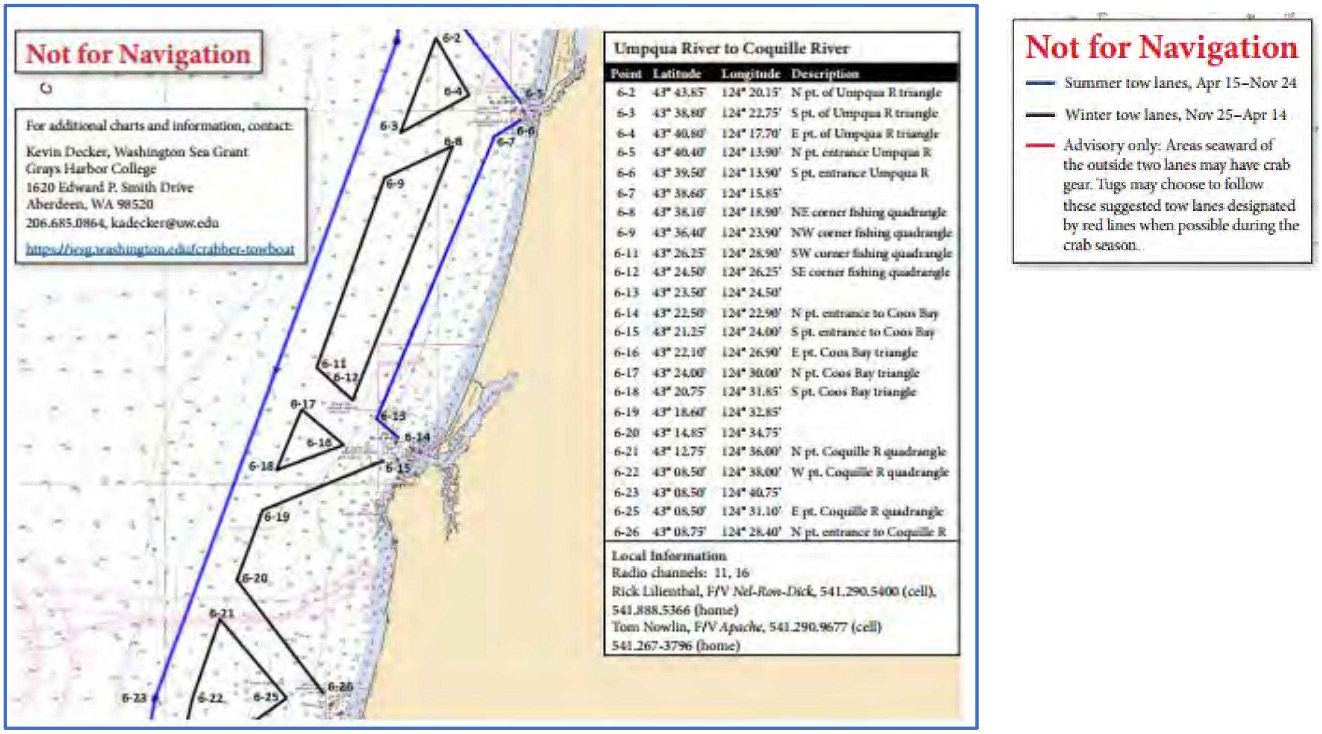


FIGURE 8 - COOS BAY TOW LANES

In June of 2017, The Oregon Dungeness Crab Commission has provided thumb drives containing the tow boat lanes along the coast in OR and WA and where the crab fisher traditionally drop their ports. These thumb drives were distributed by CBHSC to the tugboats companies (Amex, Foss, Dunlap, Brusco, Sause Brothers,). By educating both groups as to where the towing lanes and crabbing areas are, the CBHSC hopes to minimize the conflict between the two user groups.

3.8 Bridges

Coos Bay channel has three bridges running across it. Two are fixed and the other is a swing bridge for the railroad.

- The Coos Bay Link railroad bridge: This swing bridge is located 7.5 miles above the entrance, has a swing span with a vertical clearance of 12 feet in the closed position and a horizontal clearance of 197 feet in the open position. The bridgetender monitors VHF channel 18A and works on channel 13 when they are on the bridge for a train crossing. The rest of the time the bridge is unmanned and kept in the open position. For railroad status, information can be obtained from Coos Bay Rail Link at (541) 266-7245.

- The McCullough Memorial bridge is a fixed highway bridge, 8.7 miles above the entrance, has a clearance of 123 feet vertical clearance at the channel's edge and 149 feet vertical clearance at the center of the span at Mean Lower Low Water (MLLW) tide and have a horizontal clearance of 515 feet.
- 100 yards west of the McCullough bridge is an overhead power cable bridge has a vertical clearance of 167 feet.

The Charleston Channel has one bridge:

- Bascule (Charleston) Bridge: Horizontal clearance is 80 feet and vertical clearance in the closed position is 22 feet (it is a lift cantilever bridge). There are overhead power cables on the south side of the bridge with a vertical clearance of 71 feet.

3.9 Pilotage

There is no Vessel Traffic System (VTS) covering the Coos Bay area or any other harbor along the Oregon Coast.

Pilotage is compulsory for all foreign vessels and all U.S. vessels under registry (except fishing and sail vessels). Pilotage is optional for U.S. vessels in the coastwise trade that have onboard a Pilot licensed by the Federal Government for these waters. Pilotage for Coos Bay, its tributaries, and Yaquina Bay is available from the Coos Bay Pilots Association. 686 N Front Street,
Coos Bay, OR 97420; Telephone (541) 267- 6555.

The pilot boats monitor VHF-FM channels 13 and 16 and use channels 12 and 18A as working frequency. The pilot boats, COOS BAY and NORTH BEND, are 76 and 72 feet respectively long tugs with black hulls, orange bands around the house, and white superstructure. The pilot boats use the standard pilot lights (red over white) at night. Vessels are handled 24-hours a day, with weather permitting. Arrangements for pilots are usually made by ships' agents or by telephone. A 24-hour notice of the time of arrival is requested. The pilots usually board vessels about 2 miles NW of Coos Bay Approach Lighted Whistle Buoy K. Vessels are requested to maintain a speed of about 6 to 7 knots and rig the ladder, without man-ropes, about 2.5 meters (8.2 feet) above the water.

The pilots were asked about emergency procedures in the event that a ship lost power or lost steering. In nearly all cases, the pilots would allow the ship to drift forward and easily set the side of the ship into the sand. In all cases, the pilots have a standby tug (the pilot boat) which is able to influence the movement of the ship. The pilot boat always moves just ahead of the ship or alongside depending upon the orders from the pilot. The Pilots would always avoid having the ship end up crossways in the channel with a bow on one side and the stern on another side of the channel.

3.10 Towage

There are seven tugs are available and are used for docking and mooring. There are no federal or state rules or guidelines establishing escort or ship assist requirements for vessels visiting Coos Bay, OR. Escort and ship assist tugs should meet classification society standards appropriate for escort and ship assist tugs.

Escort and ship assist tugs in Coos Bay which meet the requirements for large vessels operating in narrow channels shall have their bollard pull (ahead and astern) measured as provided below.

(1) Bollard pull measurements shall be verified by a member of the International Association of Classification Societies.

(2) Bollard pull measurements verified by a member of the International Association of Classification Societies in other ports of the State shall meet the requirements of this section, provided that evidence of the results of these measurements are on file with the Coos Bay Harbor Safety Committee.

(3) Companies providing escort and ship assist tugs shall provide the Coos Bay Harbor Safety Committee with the results of the bollard pull measurements verified pursuant to these provisions.

(4) Escort and ship assist tugs whose bollard pull has not been measured and verified or are not within the scope of the definition of "bona fide sister tug", shall not be used for the escort and/or ship assist of large vessels in Coos Bay.

An escort and/or ship assist tug determined by the Coos Bay Harbor Safety Committee to be a "bona fide sister tug" may be used with the same (ahead and astern) bollard pull as the certified sister tug.

The braking force shall be re-measured after any modifications and/or repairs to the main engines, hull, shaft-drive line, or steering, that could affect the bollard pull. The new measurements must be registered with the Coos Bay Harbor Safety Committee.

Notwithstanding any other provision of this plan:

(1) The vessel master remains responsible for the safe navigation and maneuvering of the vessel in all circumstances. The requirements outlined in this plan are in addition to, and not a limitation of, any other responsibilities created by custom, law, or regulation.

(2) Where an emergency exists, the vessel master may adjust the minimum escort and/or ship assist tug requirements. For purposes of this plan, an emergency is defined as any of, but is not limited to, the following:

(A) the imminent and immediate danger to the vessel, its cargo or its crew;

(B) the imminent and immediate danger to a marine terminal, ship assist or escort tug;

(C) the imminent and immediate danger to a vessel in the proximity of the escorted vessel; or

(D) any emergency declared by the United States Coast Guard, Captain of the Port which would necessitate a modification to the provisions set forth in this plan.

TABLE 1 - COOS BAY TOWING VESSELS

Vessel Name	Registered Owner	Type	Call Sign	Horsepower	Bollard Pull
Coos Bay	Coos Bay Pilots	Propeller	WY 6046	1,700	lbs
North Bend	Coos Bay Pilots	Propeller	WUR 9793	2,000	lbs
Oregon Escort	Coos Bay Pilots	Z Drive Tug	WDD 5907	6,700	lbs
Captain Louie	Knutson Towboat	Tug	WR 7513	1,750	lbs
Centennial	Knutson Towboat	Z Drive Tug	WCY 3200	3,000	lbs
Captain Harold	Knutson Towboat	Propeller	WDG4952	2,500	lbs
Casey H	Billeter Marine	Propeller	WDH 7360	2,700	lbs

Contact information for the towboat companies can be found in Appendix B of this plan.

3.11 United States Coast Guard

The US Coast Guard is present in the area providing its search and rescue, law enforcement and marine safety and pollution response services through the following units:

3.11.1 Operational Units:

U.S Coast Guard Sector North Bend: Sector North Bend is co-located with Air Station North Bend and is oversees all operations of Sector North Bend Units. They also support operational units by providing administrative, supply, medical, engineering and communication services.

Sector North Bend Units:

- Coast Guard Cutter Orcas – the 110-foot Island Class patrol boat has been stationed in Coos Bay, OR, since 1989.

- U. S. Coast Guard Aids To Navigation Team (ANT) Coos Bay was established in 1976 and is located near the mouth of Coos Bay in the fishing and tourist community of Charleston, Oregon. Their area of responsibility ranges over 240 miles of the Oregon coast and includes 5 lighthouses, 18 primary buoys, 43 secondary buoys and 156 other lights, day beacons and fog signals.

- Coos Bay Coast Guard Station: The Station located in the town of Charleston, is on the south side of Charleston Boat Basin, 0.7 miles southeast of Coos Head. and provide search and rescue operations from the Coos River to Cape Bianco. During the summer months, Station Coos Bay operates Search and Rescue Detachments Coquille River in Bandon, OR.

- North Bend Coast Guard Air Station is at the North Bend Municipal Airport.

- Coos Head Watch Tower is staffed during breaking bar season. The watchstander logs all vessels heading out who call into the tower and provides general lookout services.

Other Units are:

- Station Depoe Bay

- Station Yaquina Bay
- Station Umpqua River
- Station Siuslaw River
- Station Chetco River

3.11.2 Marine Safety Units

While the operational units are located within the Coos Bay area, the Captain of the Port is based out of Sector Columbia River, Astoria OR, providing vessel and facility inspections, pollution response and investigation services to Coos Bay.

3.12 Harbor Regulations

The port authority, Oregon International Port of Coos Bay, is controlled by a Board of Port Commissioners and an Executive Director. Harbor regulations are prescribed by the Port Commissioners and enforced by the Executive Director. The port manager’s office is at 125 Central Avenue, Suite 300, Coos Bay, OR 97420.

3.13 Docks

Most of the deep-draft facilities in the Port of Coos Bay are in the cities of Coos Bay and North Bend. The following are the still **active and /or useable docks**:

3.13.1 Commercial Docks:

1. Cape Arago Dock/Sause Brothers (River Mile (RM) 5.4, utility/work dock
2. D.B. Western Inc. (RM 5.6, utility/work dock, vessel repair, and construction)
3. Southport Lumber Company/Southport Forest Products (RM 6.3, dead load barge slip)
4. Roseburg Coos Bay Shipping Terminal (“Roseburg”) (RM 7.9, export woodchips)
5. Ocean Terminals Dock (RM 11, inbound and outbound logs)
6. K2 Export (RM 11.5, outbound logs)
7. Tyree Oil terminal (RM 12.5 oil dock for vessels – tug and fishing vessels)
8. Oregon Chip Terminal (RM 12.5, outbound woodchips)
9. Bayshore Dock/Sause Brothers (RM 12.7, tug and barge berths)
10. ORC Operations (RM 15, currently closed)
11. Georgia Pacific (RM 15, logs in / chips out)
12. Coastal Fibre (RM 17 chips out)

3.13.2 Government Docks:

- US Army Corps of Engineers (USACE) Coos Bay Moorage Dock and
- US Coast Guard (USCG) Orcas Dock (RM 13.2, USCG and USACE vessel berths)

Contact information these facilities are located in Appendix B of this plan.

3.14 Towns and Waterways

3.14.1 South Slough

Shoal and navigable only for small boats, extends 4 miles south from its junction with Coos Bay near the entrance. A Federal project provides for a 17-foot entrance channel extending south from the junction for about 0.6 miles to the Charleston Boat Basin, thence a 16-foot channel continues to a highway bascule bridge. The channel from the junction with Coos Bay to Charleston Boat Basin is subject to shoaling. Mariners are advised to seek local knowledge when transiting this area.

3.14.2 Charleston Boat Basin

Operated and maintained by the Port of Coos Bay, is 0.3 miles north of Charleston, across the slough from Barview. The basin is used by commercial and sports fishermen. About 500 berths with electricity, gasoline, diesel fuel, water, ice, a launching ramp, and marine supplies are available. A pump out station and wet and dry winter boat storage are available in the basin. A repair facility at the basin has a drydock that can handle vessels to 300 tons, 90 feet long, and 30 feet wide, and a marine railway that can handle craft 70 feet long, 22 feet wide, and 6 feet draft for hull and engine repairs. Electronic repairs can also be made at the basin. Four fish piers are in the basin, and three fish packing facilities are just south of the basin on South Slough. Coos Bay Coast Guard Station is on the south side of the basin.

A Coast Guard buoy storage area is in Coos Bay about 150 yards E of the channel and about 2.5 miles above the entrance jetties.

The highway bridge over South Slough, 1 mile south of the entrance, has a bascule span with a clearance of 22 feet. Power and television cables south of the bridge have a least clearance of 71 feet.

The west shore of Coos Bay as far as the bend is formed by a sandspit covered with dunes, partly wooded, and in some places as much as 90 feet high. On the E shore and above the bend are low rolling hills with houses and several prominent buildings.

3.14.3 Haynes Inlet and North Slough

Haynes Inlet and North Slough join the bay through a common entrance on the north side and are navigated by small boats. Haynes Inlet and North Slough channels are marked by private day beacons. A causeway with a fixed bridge over North Slough has a clearance of 15 feet. The causeway extends east and joins the State highway fixed bridge over Haynes Inlet, which has a clearance of 20 feet (27 feet at center).

3.14.4 North Bend

North Bend is 9.5 miles above the Coos Bay entrance and is a city that transitioned from sawmills and factories to its present tourism economy. A number of the docks where lumber is shipped are located in North Bend. The North Bend Fire Department has a small fireboat and launches from existing boat ramps. Coos Bay, 12 miles above the entrance, is the second city on the bay and is the distributing center for the area, which is primarily devoted to lumbering, fishing, and agriculture.

3.14.5 Empire District

The City of Coos Bay also includes the Empire district, which is 4 miles above the entrance. North Bend and Coos Bay form practically one continuous city extending along the shore from North Point to the mouth of Coalbank Slough.

Three sloughs empty into Coos Bay between the city of Coos Bay and Coos River.

- Coalbank Slough which is unused by boats.
- Isthmus Slough is used for logging operations to Millington. The highway bridge across the slough has a bascule span with a clearance of 18 feet. The overhead power and television cables just north of the bridge, and the overhead power cable 0.9 miles south of the bridge have clearances of 100 and 150 feet, respectively.
- Catching Slough is navigable for several miles by light-draft vessels. The fixed highway bridge across the mouth has a clearance of 40 feet. The power cable for about 1.7 miles above the bridge have a minimum clearance of 57 feet; other overhead cables upstream have clearances of 13 feet.

3.14.6 Coos River

The river empties through two channels into the bay at its head. The north unmarked channel follows the east side of the bay and empties abreast of North Bend. Marshfield Channel, marked by a lighted range, lights, and buoy, crosses the flats and empties abreast the city of Coos Bay. Coos River divides at a point 3.2 miles above Graveyard Point into South Fork and Millicoma River. A highway bridge across the river, 0.9 miles above Graveyard Point, has a lift span with clearances of 28 feet down and 54 feet up. The least clearance of the overhead power cables crossing Millicoma River is 40 feet. Allegany, 7.5 miles above the confluence, is the head of navigation on Millicoma River. Dellwood, 8.2 miles above the confluence, is the head of navigation on South Fork. A fixed highway bridge crossing South Fork 0.5 mile above the confluence has been removed; two concrete piers remain. A fixed highway bridge crossing South Fork 1.9 miles above the confluence has a clearance of 38 feet. Several overhead power and telegraph cables cross South Fork; least clearance is 42 feet

4 Coos Bay Harbor Conditions

Regional Harbor Conditions This section provides a description of existing and expected conditions of weather, tidal ranges, tidal currents and other factors which might impair or restrict visibility or impact vessel navigation.

4.1 Weather

4.1.1 Fog

The area is subject to fog conditions very similar to many west coast ports. Fog can be found anywhere within Coos Bay and its tributaries. Fog occurs mostly during summer and fall though is known to occur during other seasons too.

4.1.2 Storms

During the winter is when the port experiences heavy weather with increasing winds and storm conditions. Weather delays, driven by storms including gale and storm winds (winds in excess of 39 miles per hour), are infrequent in the area and account for only 3-10 days per year.

FIGURE 9 - HEAVY WEATHER AT THE COOS BAY BAR

4.1.3 Prevailing winds

Prevailing winds in the offshore sector are southerly winds, 15-30 knots, in the summer and most of the year but shifting to northerly winds in the winter. Prevailing NW winds and winter southerly storms.

- 25 knots winds and above affect big ship movements
- 20-25 knots winds affect commercial fishing and recreational boats
- Consistently heavier north winds during the summertime
- Winter winds from the south
- 35-knot winds typically associated with fronts
- 90-knot sheer winds once or twice a year
- Wind blows across channel out of North Slough
- Tugs and tows get set by winds onto aids to navigation

Deep draft ships are warned of anchoring offshore during winter while awaiting calmer winds to transit. The rapid and severe onset of weather may expose the vessel to the risk of dragging ashore.

Existing Mitigations:

- Pilots move ships in during the morning when it is calmer before winds pick up
- Have ample warning of approaching fronts

- The warning signs and lights at the entrance of the bay to alert operators to bar conditions
- Warning signs and lights at CG Station and boat ramps alert operators to bar conditions
- Telephone numbers available from which to obtain bar conditions
- Tune into AM radio channel 1610 as per the Bar warning sign
- Continuing education

NOAA provides weather forecast and actual weather conditions can be obtained online.

4.2 Tide and Currents

Since the tides at Coos Bay are semi-diurnal (occurring twice per day) there are two flood tides, two ebb tides, and four (4) slack tides (2 high slack and 2 low slack) in almost every 24 hour period. The times of high and low tides and the times of the tidal currents move nearly an hour forward every day.

At Coos Bay, the ebb tide is the condition which causes the most challenging conditions at the bar channel entrance. A strong ebb tide (often abetted by a strong river current) rushes out of the entrance channel. When it meets a strong onshore wind, sea, and swell, the waves can become very steep and then fall or break.

Tidal currents at the entrance are stated to travel in the direction 100° true during flood tides. This is generally an easterly direction into the harbor. During ebb tides (water moving out of the harbor) the direction of the current is 280° true. Predicted tidal currents vary from around one knot to almost 4 knots. Current observations in the entrance to Coos Bay indicated a velocity of about 2 knots. The greatest observed ebb velocity was a little over 3 knots. During long runouts, an ebb current of 5 knots has been reported at Guano Rock.

The tidal range between Mean Lower Low Water (MLLW) and mean higher high water (MHHW) is 7.5 feet near the open sea channel entrance at Charleston and 6.7 feet approximately in Empire. The lowest high tides are 4.2 to 5 feet above MLLW. Extreme low and high water are 3.0 feet below and 10.5 feet above MLLW, respectively. Based on measured tide data at Charleston, the tides are above +6 feet MLLW about 75% of the time and above +7 feet MLLW about 10% of the time.

In summary:

- Currents 3 knots and can be 5 knots at buoy #4 in jaws of jetty entrance
- Less than 3 knots in sloughs and creeks
- The tidal range of 7 feet on average
- Port area currents are tidal but during high river stages and heavy rains, the tide can be river driven
- There are cross-currents at:
    - The railroad bridge coming out of North Slough
    - Marshfield Channel junction coming down Coos River
    - Charleston coming out of South Slough

  - Jarvis Turn

Existing Mitigations:

- Pilotage for required vessels
- Local knowledge of most port users
- Tide and current tables and predictions
- Tug companies have policies about what can be done on ebb and flood tides
- USACE tide gauges along the river can be used
- USCG announcements for the time of next tide change
- When the water is brown you know that somethin' ain't right
- NOAA provides river flow rate information

New ideas:
Information exchange can be improved between members of the port community through the Harbor Safety Committee. For example:

- The USACE could share tide gauge information with other users.
- The Sheriff's Department may share river height gauge information currently collected for flood prediction.
- The Sheriff's Department may include the Harbor Safety Committee membership to emergency notifications to expand information input.
- Tug companies could share policy information based on local knowledge

4.3 Other Weather Conditions

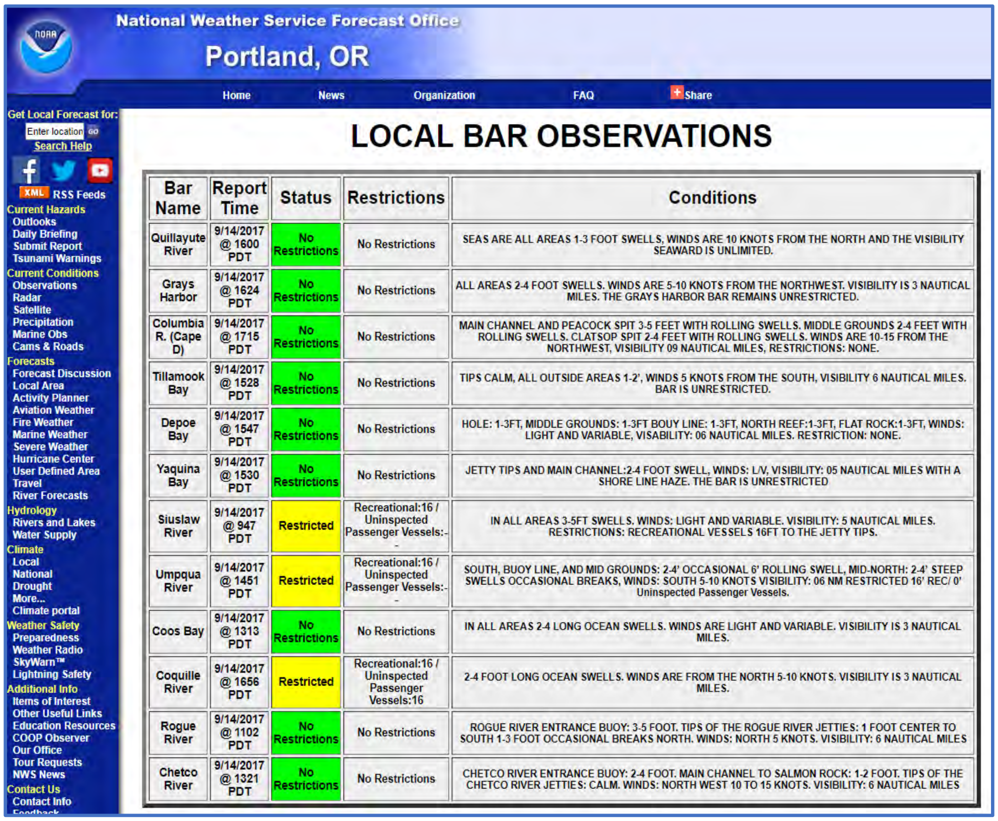
4.3.1 Crossing the Bar:

One of the main differences between Coos Bay and other harbors is the occasional occurrence of a "breaking bar" at the channel entrance. The "breaking bar" is a condition where the predominantly westerly seas and swells (often in storm conditions) meet an outgoing ebb tide which causes the waves to become quite steep, and to cascade onto the sea below. These breaking waves are very challenging to small craft and have led to several serious incidents over the years.

While this breaking bar can create spectacular conditions for small craft, the deep-water ship channel rarely experiences conditions closing the bar. The number of days per year when the bar channel is closed to shipping averages between 3 and 10 days per year.

The bar is the area where the deep waters of the Pacific Ocean meet with the shallower waters near the mouth of the river. Most accidents and deaths that occur on coastal bars are from capsizing. Coastal bars may be closed to recreational boats when conditions on the bar are hazardous. Failure to comply with the closure may result in voyage termination and civil and/or criminal penalties. The regulations are enforced by Coast Guard boarding teams. Improper loading and/or overloading are major causes of capsizing. Improper/overloaded boats have less stability and less freeboard, which can allow seas to break into the vessel, causing the boat to become even less stable. Boats are more likely to capsize when crossing the bar from the ocean because the seas are on the stern and the boater may have less control over the vessel. Boaters must make sure the bar is safe prior to crossing

There are four tides each day (two high and two low) in the Pacific Northwest. Tidal currents may gain tremendous velocity, particularly when the ebb current is augmented by river runoff. It is extremely dangerous to get caught on the bar during strong ebb current. Even on days that are relatively calm, fast-moving ebb can create bar conditions that are too rough for small craft.



National Weather Service Forecast Office

Portland, OR

LOCAL BAR OBSERVATIONS

Bar Name	Report Time	Status	Restrictions	Conditions
Quillayute River	9/14/2017 @ 1600 PDT	No Restrictions	No Restrictions	SEAS ARE ALL AREAS 1-3 FOOT SWELLS, WINDS ARE 10 KNOTS FROM THE NORTH AND THE VISIBILITY SEAWARD IS UNLIMITED.
Grays Harbor	9/14/2017 @ 1624 PDT	No Restrictions	No Restrictions	ALL AREAS 2-4 FOOT SWELLS. WINDS ARE 5-10 KNOTS FROM THE NORTHWEST. VISIBILITY IS 3 NAUTICAL MILES. THE GRAYS HARBOR BAR REMAINS UNRESTRICTED.
Columbia R. (Cape D)	9/14/2017 @ 1715 PDT	No Restrictions	No Restrictions	MAIN CHANNEL AND PEACOCK SPIT 3-5 FEET WITH ROLLING SWELLS. MIDDLE GROUNDS 2-4 FEET WITH ROLLING SWELLS. CLATSOP SPIT 2-4 FEET WITH ROLLING SWELLS. WINDS ARE 10-15 FROM THE NORTHWEST, VISIBILITY 09 NAUTICAL MILES, RESTRICTIONS: NONE.
Tillamook Bay	9/14/2017 @ 1528 PDT	No Restrictions	No Restrictions	TIPS CALM, ALL OUTSIDE AREAS 1-2', WINDS 5 KNOTS FROM THE SOUTH, VISIBILITY 6 NAUTICAL MILES. BAR IS UNRESTRICTED.
Depoe Bay	9/14/2017 @ 1547 PDT	No Restrictions	No Restrictions	HOLE: 1-3FT, MIDDLE GROUNDS: 1-3FT BOUY LINE: 1-3FT, NORTH REEF:1-3FT, FLAT ROCK:1-3FT, WINDS: LIGHT AND VARIABLE, VISABILITY: 06 NAUTICAL MILES. RESTRICTION: NONE.
Yaquina Bay	9/14/2017 @ 1530 PDT	No Restrictions	No Restrictions	JETTY TIPS AND MAIN CHANNEL:2-4 FOOT SWELL, WINDS: L/V, VISIBILITY: 05 NAUTICAL MILES WITH A SHORE LINE HAZE. THE BAR IS UNRESTRICTED
Siuslaw River	9/14/2017 @ 947 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:--	IN ALL AREAS 3-5FT SWELLS. WINDS: LIGHT AND VARIABLE. VISIBILITY: 5 NAUTICAL MILES. RESTRICTIONS: RECREATIONAL VESSELS 16FT TO THE JETTY TIPS.
Umpqua River	9/14/2017 @ 1451 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:--	SOUTH, BUOY LINE, AND MID GROUNDS: 2-4' OCCASIONAL 6' ROLLING SWELL, MID-NORTH: 2-4' STEEP SWELLS OCCASIONAL BREAKS, WINDS: SOUTH 5-10 KNOTS VISIBILITY: 06 NM RESTRICTED 16' REC/ 0' Uninspected Passenger Vessels.
Coos Bay	9/14/2017 @ 1313 PDT	No Restrictions	No Restrictions	IN ALL AREAS 2-4 LONG OCEAN SWELLS. WINDS ARE LIGHT AND VARIABLE. VISIBILITY IS 3 NAUTICAL MILES.
Coquille River	9/14/2017 @ 1656 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:16	2-4 FOOT LONG OCEAN SWELLS. WINDS ARE FROM THE NORTH 5-10 KNOTS. VISIBILITY IS 3 NAUTICAL MILES.
Rogue River	9/14/2017 @ 1102 PDT	No Restrictions	No Restrictions	ROGUE RIVER ENTRANCE BUOY: 3-5 FOOT. TIPS OF THE ROGUE RIVER JETTIES: 1 FOOT CENTER TO SOUTH 1-3 FOOT OCCASIONAL BREAKS NORTH. WINDS: NORTH 5 KNOTS. VISIBILITY: 6 NAUTICAL MILES
Chetco River	9/14/2017 @ 1321 PDT	No Restrictions	No Restrictions	CHETCO RIVER ENTRANCE BUOY: 2-4 FOOT. MAIN CHANNEL TO SALMON ROCK: 1-2 FOOT. TIPS OF THE CHETCO RIVER JETTIES: CALM. WINDS: NORTH WEST 10 TO 15 KNOTS. VISIBILITY: 6 NAUTICAL MILES

FIGURE 10 - NATIONAL WEATHER SERVICE - LOCAL BAR OBSERVATIONS

Observed weather and bar conditions are updated every four hours or more frequently if there is a significant change in weather. Marine Information Broadcasts on Channel 16 VHF FM are conducted by the Coast Guard when hazardous bar conditions and restrictions are put in place or are lifted. Mariners are strongly encouraged to monitor channel 16 VHF/FM for all notices and weather updates. The AM radio broadcast is audible within a 6-mile radius from the Coast Guard Station in Charleston. It provides a continual broadcast on radio station 1610 AM containing bar conditions, bar restrictions, and local weather. As a public service Radio Station KBBR (1330 kHz) broadcasts bar conditions once each hour during the summer months. Current weather advisories are also posted at the Coast Guard Station in Charleston. You can also access current bar conditions and restriction on your smartphone or handheld device by going to, http://www.wrh.noaa.gov/pqr/marine/BarObs.php, as seen above.[1]

Existing Mitigations:

- Check the weather and tide conditions by:
  - Monitor Marine Information Broadcasts on Channel 16 VHF FM
  - Tune in to AM radio channel 1610 and Public Radio Station KBBR (130 kHz)

[1] The US Coast Guard published a handout which addresses the hazards of crossing the bar. The content of this handout, available at https://www.uscg.mil/d13/dpw/docs/Coos_Bay_Bar_Crossing_Handout.pdf

  - Log into NOAA's website http://www.wrh.noaa.gov/pqr/marine/BarObs.php

- Check with other boaters or the Coast Guard to find out the condition of the bar.
- Always know the stage of the tide
- Cross the bar during slack water or on a flood tide, when the seas are normally calmest.

If you are caught on a rough bar running in:

- Make sure everybody aboard is wearing a personal flotation device.
- Keep the boat square before the seas.
- Keep the boat on the back of the swell. Ride the swell and stay clear of the following wave.
- Avoid sudden weight shifts from passengers, cargo or gear moving around in the boat. If possible, have passengers lie down as near the centerline of the boat as possible. Do not allow the waves to catch your boat on the side (beam). This condition is called broaching, and can easily result in capsizing.

4.4 Special Navigation Conditions

4.4.1 *North Jetty conditions*

In 2012, the Army Corps of Engineers completed a Major Maintenance Report (MMR) for the Coos Bay Jetties

Concerns (in order of greatest to least risk):

- North Jetty root and north spit sediment management (breach of North Spit)
- Structural stability of North Jetty head
- Structural stability of North Jetty trunk
- Structural stability of South Jetty root

MMR looked at 19 potential measures (individual project elements) used to create 9 alternatives (various combinations of measures). The 9 alternatives were evaluated against each other and the existing condition and the following were the preferred solutions:

Proposed mitigation:

- Buried revetment at log spiral bay (as seen by the dark blue line in Figure 12 below)
- Rebuild 400 linear feet of jetty root to +16' MLLW (light blue)
- Re-nourish log spiral bay
- Repair a low reach of north jetty root to +20' MLLW (pink)
- Repair targeted reaches of the north jetty trunk (green)
- Rubble-mound head at present location (pink)

FIGURE 11 - JETTY AND AREAS OF PROPOSED ALTERNATIVES

Engineering, Research and Design Center (ERDC) is currently conducting a physical model of the entrance to determine detailed jetty head design.

This project is currently in Detailed Design Report phase (DDR). After the DDR phase is completed, the Plans and Specifications phase (P&S) begins. After P&S phase is completed, rock procurement and construction phase begins. This is an evolving project.

Existing mitigation:

- Pilots know to proceed clearly out of the channel before turning north or south.
- Charts indicate submerged sections of the jetty

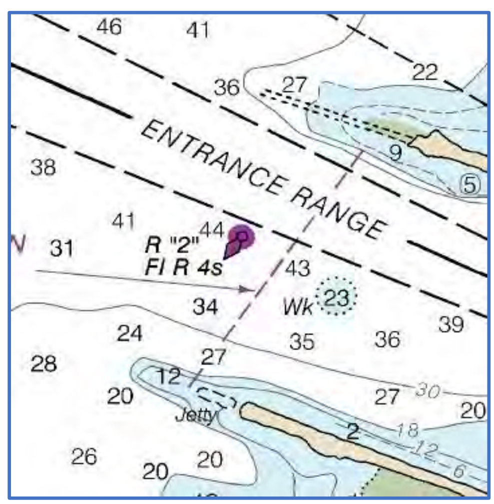


FIGURE 12 - CHART SHOWING SUBMERGED JETTIES

4.4.2 *Upper Jarvis Range Location*:

As previously mentioned with regards to the Coos Bay Rail Bridge, mariners should use extreme caution when passing through the bridge because the location of the Upper Jarvis ranges in relation to the bridge opening is offset 35 feet to the North, resulting in vessel passing closer to the center support of the bridge and potentially alliding with it. The Upper Jarvis Range, while centered in the channel is not centered to the bridge opening.

Existing Mitigation:

- Mariners need to be aware of this offset.
- Chart 18587 clearly indicates the location of range in relation to the swing bridge in its open position.

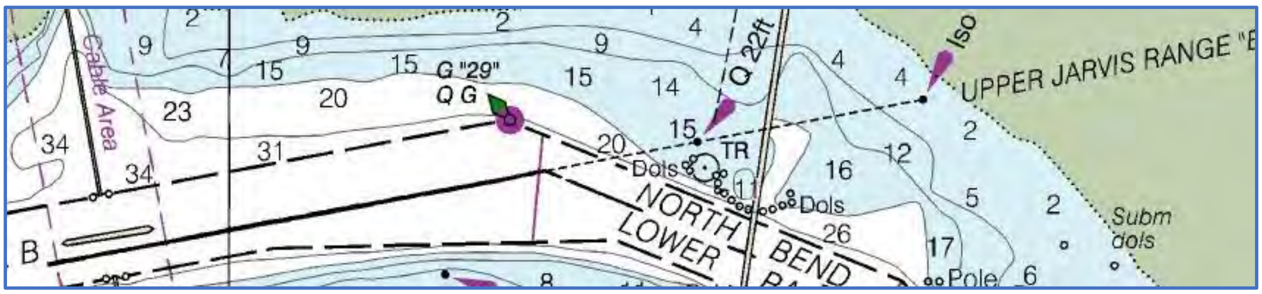


FIGURE 13 - CHART SHOWING UPPER JARVIS RANGE AND BRIDGE ALIGNMENT

4.4.3 *FAA Air Draft Restrictions*

NOAA recently added the following information in the Coast Pilot regarding vessels with a vertical clearance of 144ft and above.

Vessel Reporting Advisory

Operations in the Vicinity of Southwest Oregon Regional Airport

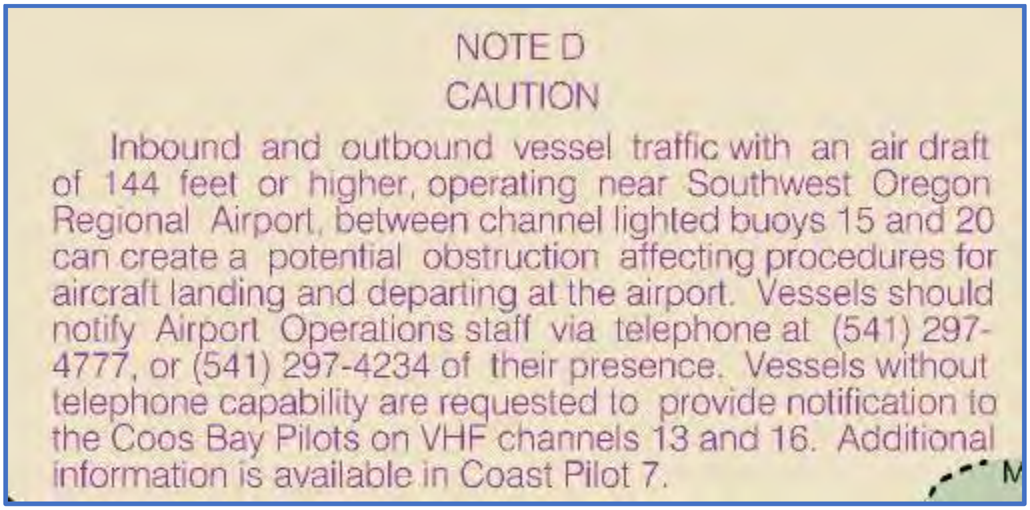
Inbound and outbound vessel traffic near Southwest Oregon Regional Airport may affect procedures for a1rcraft landing and departing at the airport. Vessels With an air draft of 144 feet or greater present a potential obstruction to airspace that require advisories be issued to aircraft by air traffic Controllers and in some case, runway use may need to be restricted. Notification by vessels exceeding 144 feet air draft (including raised cranes or other cargo gear), when operating in vicinity of the airport is essential to provide aircraft important notice of potential airspace obstruction during instrument approaches.

Vessels with an air draft height of 144 (44 meters) or greater are advised to report the following information:
• The vessel's name, a point of contact and a call-back method of communication to the ship.
• The vessel's maximum air draft height (including masts, cranes, antenna or other projections).
• If inbound from sea, report time of arrival at Coos Bay Channel Lighted Buoy 15 (with at least 10 minutes advance notice), and again when past Coos Bay Channel Lighted Buoy 20.
• If outbound to sea. report time of arrival at Coos Bay Channel Lighted Buoy 20 (with at least 10 minutes advance notice), and again when past Coos Bay Channel Lighted Buoy 15.

Notification can be made to the Airport Operations staff' via telephone at 541-297-4777 or 541-297-4234. Vessels without telephone capability are requested to provide notification to the Coos Bay Pilots on VHF-FM channels 13 and 16, to be relayed to the Airport operations personnel.

FIGURE 14 - FAA ADVISORY IN THE COAST PILOT

Upon notification, Airport traffic controllers will notify in and outbound aircraft, or restrict the runway until the vessel has passed. This information is also included in Chart 18587 as Note D Caution:


NOTE D

CAUTION

Inbound and outbound vessel traffic with an air draft of 144 feet or higher, operating near Southwest Oregon Regional Airport, between channel lighted buoys 15 and 20 can create a potential obstruction affecting procedures for aircraft landing and departing at the airport. Vessels should notify Airport Operations staff via telephone at (541) 297-4777, or (541) 297-4234 of their presence. Vessels without telephone capability are requested to provide notification to the Coos Bay Pilots on VHF channels 13 and 16. Additional information is available in Coast Pilot 7.

FIGURE 15 - FAA ADVISORY IN CHART 18587

NOTE: Pilots monitor VHF 13 and 16 only when on duty on vessels.

4.4.4 Upper Bay Shoaling.

The USACE has not dredged the navigation channel past RM 12.8 to 15.2 since 2010, due to lack of deep draft vessel traffic.

4.4.5 Transiting Rail Road bridge.

All vessels should ensure the Rail bridge is open, as it swings shut when trains are expected to pass over it. The train/bridge schedule is variable and not posted anywhere online or made publicly available. The bridge master can be reached via radio or telephone when they are on the bridge. Pilots onboard commercial vessels also ask the tugboats ahead of them, about the status of the bridge.

Swing bridges are required to have lights. Each swing span of every through swing bridge shall be lighted with three lanterns so that when viewed from an approaching vessel the swing span when closed will display three red lights on top of the span structure (see CFR 118.70 Lights in swing bridges).

Mariners should use extreme caution when passing through the bridge because of unpredictable changing winds, currents, and sea conditions reported in this area.

5 Conditions specific to Navigation Rule 9 - Narrow channel

This section is an assessment of current safety problems or conflicts with commercial, recreational, sailing and fishing vessels as it relates to a violation of Rule 9 (Narrow Channels Rule) of the Inland Navigational Rules Act (33 USC 2009). Each section of Rule 9 (*in italics*) has been broken down and issues for each assessed.

5.1 Keeping to starboard side outer limit of the channel

> *"(a) (i) A vessel proceeding along the course of a narrow channel or fairway shall keep as near to the outer limit of the channel or fairway which lies on her starboard side as is safe and practicable.*

There are currently no issues.

5.2 Down-bound right of way

Not applicable as the Coos River is not a Western river.

5.3 Impeding passage of vessels that only navigate in the channel

> *(b) A vessel of less than 20 meters in length or a sailing vessel shall not impede the passage of a vessel that can safely navigate only within a narrow channel or fairway.*

This has not been a major issue as most small vessels are aware to operate outside of the deep draft vessel channel when ships are approaching.

5.4 Fishing vessels impeding the passage of any other vessel

> *(c) A vessel engaged in fishing shall not impede the passage of any other vessel navigating within a narrow channel or fairway.*

5.4.1 Recreational fishing vessel

Recreational fishing vessels fish in the main channel and are known to tie up or anchor by the bridge pylons. This type of operation may create a navigational hazard for other waterway users by impeding or restricting their passage.

Recommendations:
Increase education of the waterway users to the potential hazards within the Coos Bay user community.

5.4.2 Derelict crab pots

Assessment

Some recreational fishing vessels never recover their crab pots that were either dropped in the channel or drift over into the channel. Vessels navigate over crab pots which results in their lines, and associated debris, getting caught in the propellers. This has caused multiple vessels to lose propulsion/steering and is a safety risk when vessels try to retrieve the entangled pots as they are not equipped to do so.

Recommendations
Increased education to the recreational crabbing community and commercial operators.
The Dungeness crab commission has derelict crab cop recovery program in place which involves financial incentive to fishermen to recover the pots.

5.4.3 Seasonal recreation fishermen

Assessment
The density of recreational fisherman, especially during fall salmon season, can pose hazards to navigation. The North Bend range is the most popular place for recreational salmon fishing in the Fall when there can be hundreds of small vessels in and out of the channel.

Recommendation
Increased education to the salmon fishing community regarding Rules of the Road and safe boating practices.

5.5 Crossing narrow channel

> *(d) A vessel must not cross a narrow channel or fairway if such crossing impedes the passage of a vessel which can safely navigate only within that channel or fairway. The latter vessel must use the signal prescribed in Rule 34(d) (§ 83.34(d)) if in doubt as to the intention of the crossing vessel.*

There are currently no issues.

5.6 Overtaking in a narrow channel

> *(e) (i) In a narrow channel or fairway when overtaking, the power-driven vessel intending to overtake another power-driven vessel shall indicate her intention by sounding the appropriate signal prescribed in Rule 34(c) (§ 83.34)(c)) and take steps to permit safe passing. The power-driven vessel being overtaken, if in agreement, shall sound the same signal and may, if specifically agreed to, take steps to permit safe passing. If in doubt she shall sound the danger signal prescribed in Rule 34(d) (§ 83.34)(d)). (ii) This Rule does not relieve the overtaking vessel of her obligation under Rule 13 (§ 83.13).*

There are currently no issues.

5.7 Vessel approaching a bend or area that obscures other vessels

> *(f) A vessel nearing a bend or an area of a narrow channel or fairway where other vessels may be obscured by an intervening obstruction shall navigate with particular alertness and caution and shall sound the appropriate signal prescribed in Rule 34(e) (§ 83.34(e)). (g) Any vessel shall, if the circumstances of the case admit, avoid anchoring in a narrow channel."*

There are currently no issues.

6 Aids to Navigation

This section describes the fixed navigational hazards specific to the region and the aids to navigation systems in place to minimize the risk of contact with these hazards.

6.1 Types of Aids to Navigation

6.1.1 Rough Bar Advisory Sign

Coos Bay bar is a regulated navigation area and as such, the Coast Guard has established Coos Bay South Slough Regulated Navigation Warning Sign, a rough bar advisory sign, on the east end of the breakwater at Charleston Boat Basin in about 43°20'48"N., 124°19'18"W to promote safety for small-boat operators. The sign is diamond-shaped, painted white with an international orange border, and with the words “Rough Bar” in black letters. The sign is equipped with two quick flashing amber lights that will be activated when hazardous conditions exist and the bar is restricted to recreational and uninspected passenger vessels. Boaters are cautioned, however, that if the lights are not flashing, it is no guarantee that the sea conditions are favorable.

In accordance with 33 CFR 165.1325, the U.S. Coast Guard has the authority to restrict all recreational and uninspected passenger vessels from crossing the bar when hazardous conditions exist. Failing to comply with posted bar restrictions may result in a maximum civil penalty of $25,000.00

Additional warning signs are located at the boat ramps areas in Charleston and Empire. These signs are blue in color and have amber flashing lights that read: Warning When Flashing, Bar Restrictions in Effect, Tune to 1610 AM. When the amber lights are flashing on any of the warning signs hazardous conditions are present and a bar restriction is in place and mariners should tune in to listen to the restriction information.

6.1.2 Automatic Identification System (AIS)

AIS allows ports and ships installed with the system to automatically know where ships are located as viewed on the radar screen and share pertinent information about each vessel. While not currently used by the port of Coos Bay, AIS receiving capabilities could be installed and be used to the advantage of the agencies, the port, and ship husbandry companies. Since the port does not have Vessel Traffic Management System or use AIS; vessel transiting Coos Bay are responsible for their own safe passage.

6.1.3 Differential Global Positioning System (dGPS)

Differential Global Positioning System (dGPS) is an enhancement to Global Positioning System that provides improved location accuracy, from the 15-meter nominal GPS accuracy to about 10 cm in case of the best implementations.

The United States Coast Guard (USCG) runs its National dGPS (NGDS) on the longwave radio frequencies between 285 kHz and 325 kHz near major waterways and harbors. The USCG's

NGDPS is jointly administered with U.S. Department of Transportation's Federal Highway Administration. It consists of broadcast sites located throughout the inland and coastal portions of the United States. While available in the area, it is unreliable and not frequently used.

6.2 Evaluation of Navigational Hazards

Any channel modifications will require a new review of the Aids to Navigation (ATON) needs and any changes to the positioning of ATON by the USCG should be reviewed by CBHSC. The list of ATON under review by the USCG and CBHSC is included in Appendix C of this plan.

As previously mentioned, Coos Bay has several navigational hazards most of which are outside of the Federal navigational channel and as such are more likely to be a concern to small boats that can navigate outside of the channel. Deep draft vessels should still be aware of some of these hazards as they are located close to the channel; ex: submerged jetties and Guano Rock.

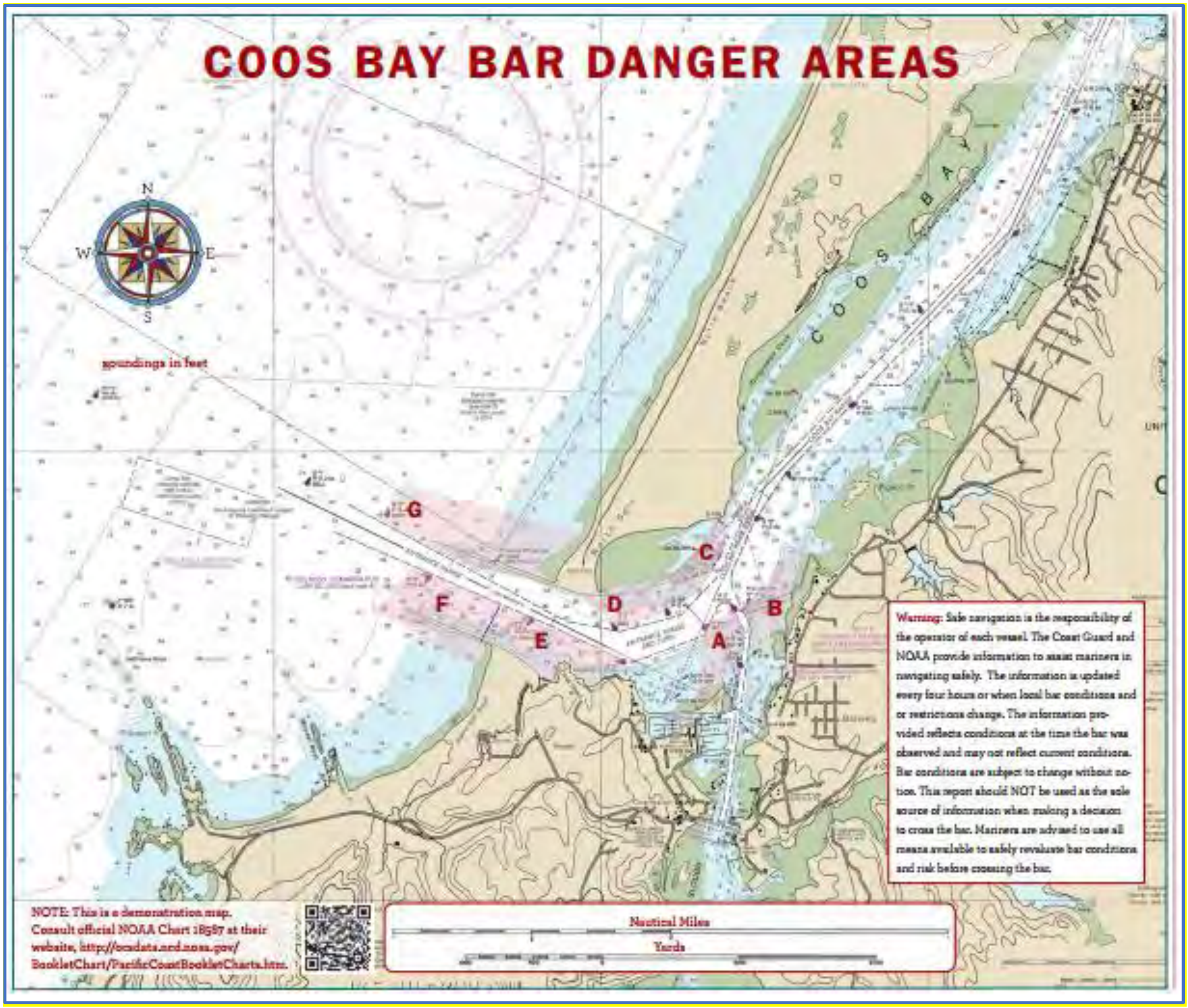


FIGURE 16 - COOS BAY BAR DANGER AREAS[2]

6.2.1 Navigational hazards affecting boats

A. South Slough Sand Spit. As you leave the Charleston Boat Basin, the South Slough Sand Spit extends north and parallel to the channel from South Slough Red Lighted Marker #8, approximately 450 yards north towards South Slough Red, Lighted Marker #4. South Slough Lighted Buoy 2 marks the north end of the sand spit. It is dangerous. DO NOT CROSS THIS AREA.

B. South Slough/Charleston Channel submerged jetty. From the entrance to the Charleston Channel from Green Lighted Marker #1, shoreward marks the end of the submerged jetty. This jetty is visible only at low water. When departing the Charleston Boat Basin, stay in the South Slough Charleston Channel to the left of Green Lighted Marker #1 at all times.

[2] https://www.uscg.mil/d13/dpw/docs/Coos_Bay_Bar_Crossing_Handout.pdf

C. Sandspit, North Beach. This area, commonly known as the cribs is located shoreward of buoy 7 and is dangerous due to its shallow depth and submerged jetties. Occasionally, on strong ebb tides, breakers will form in this area. This area should also be avoided because of the possibility of aground or striking submerged jetties and pilings. Inbound and outbound commercial tugs and deep draft vessels also pass close to channel boundaries and cannot stop for obstructions or small vessels in the channel.

D. The area north of Coos Bay Channel lighted buoy 5 and 5A. This area is shallow and can be very dangerous when there are any large swells on the bar or during ebb tide. Breakers are very common in this area, and without warning. While vessels transit this area on occasion, this area should be avoided. The main channel is the safest navigable water.

6.2.2 Navigational hazards affecting vessels

E. South Jetty, Guano Rock area. This is a very dangerous area because of shoals extending out from the south jetty to the entrance channel. Breakers are frequently experienced from Guano Rock Lighted Whistle Buoy 4 and sometimes breaks onto Coos Head extending out to sea. Exercise extreme care in this area at all times, especially on ebb tides. Submerged rock by the channel entrance only has about 10 feet of water above it at low tide. *Buoy R 4 marks the rock, but it has washed downstream from the rock and the US Coast Guard is not planning on changing it.*

FIGURE 17 - GUANO ROCK BY COOS HEAD

F. South jetty submerged 100 yards. The outward end of the south jetty is submerged from the visible end of the jetty. NEVER CROSS THIS AREA. There are breakers in this area most of the time. When departing the bar southbound, be sure to pass seaward of Coos Bay south jetty Lighted Gong Buoy 2 before turning to the south.

G. North jetty submerged. The North Jetty extends approximately 300 yards to the West of the visible tip. The seaward end of the jetty is submerged from the visible tip towards Coos Bay North Jetty Lighted Whistle Buoy 3. NEVER CROSS THIS AREA. There are breakers in this area most of the time. When departing the bar northbound, be sure to pass seaward of Coos Bay North Jetty Lighted Whistle Buoy 3 before turning to the north."

6.3 Action Summary on Aids to Navigation

The list of ATON under review by the USCG and CBHSC is included in Appendix C of this plan.

7 Spill Response

7.1 Coos Bay Response Cooperative

The Coos Bay Response Cooperative, Inc. (CBRC) is a non-profit marine industry-owned association consisting of the terminal operators in the Coos Bay harbor. CBRC was formed in 1994 and acts as an initial responder. Additional contractors would be called out as necessary depending on the nature and duration of the response. Within 24 hours, the responsible party will bring additional contractors as necessary and reasonable.

The CBRC has developed this "Umbrella" Oil Spill Contingency Plan (Plan) to cover general commercial vessels calling at berths in Coos Bay. Oil Terminal Owner/Operators and Tank Vessels including Self Propelled Tankers and Tank Barges are covered by their respective Vessel/Facility Plans and may site the resources listed in the Plan if they are members of the CBRC and have executed appropriate Service Agreements. The geographic area covered by this Plan consists of Coos Bay from the Isthmus Slough Bridge at river mile 15 to the mouth (at river mile 0). Pollution response equipment accessible to CBRC is located at the following facilities/locations: Roseburg Coos Bay Shipping Terminal; Ocean Terminal; Carson Davis Oil, Tyree Oil, Market Avenue and SOMAR and includes, boom, boom boat, skimmers, skiffs, storage tanks, cab over truck and high-power jets.

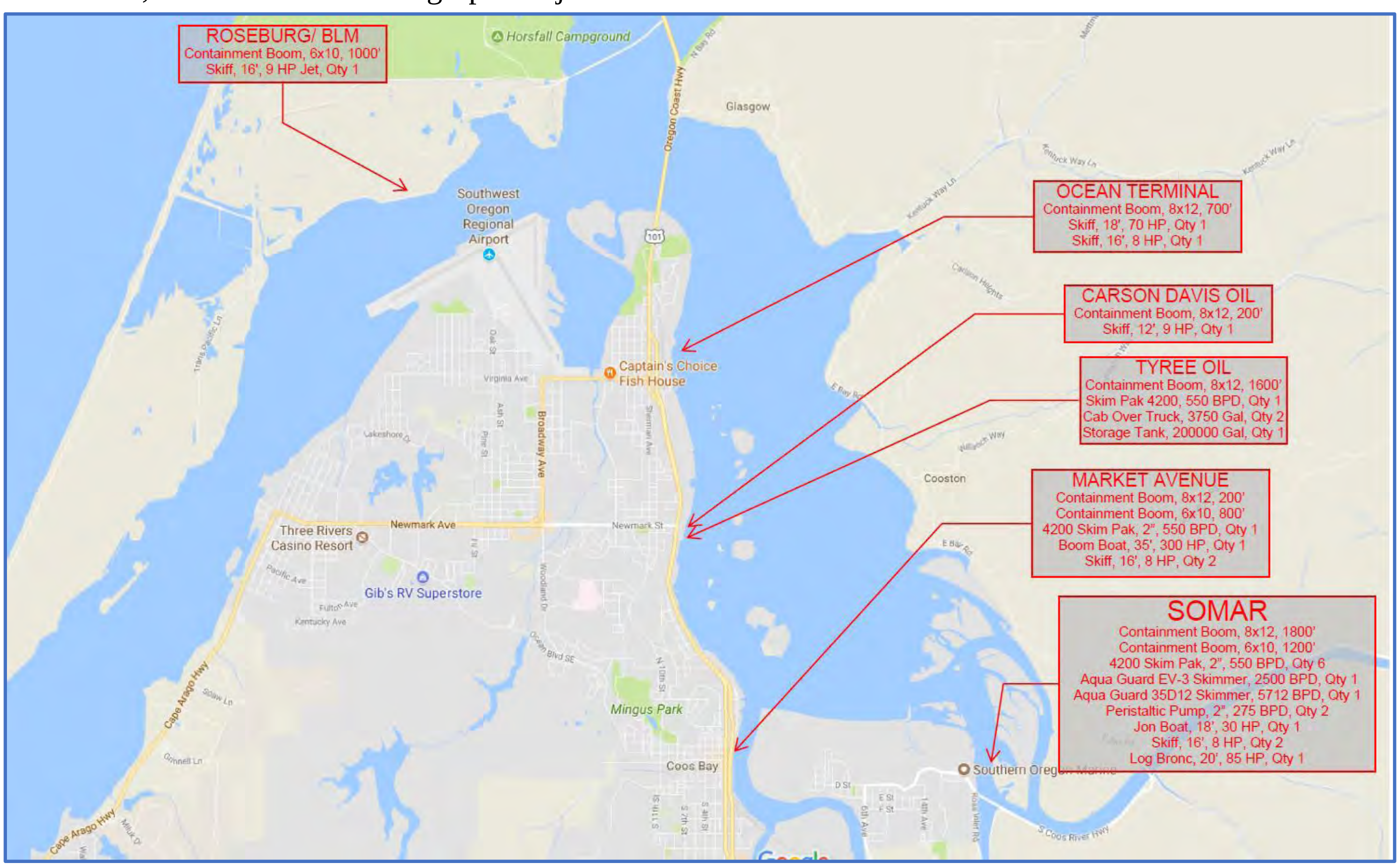


FIGURE 18 - CBRC OIL SPILL EQUIPMMENT LOCATION MAP

In response to a spill, responsible parties, Oil Spill Response Organizations as well as Federal, State and local agencies will implement an Incident Command Systems to effectively respond to the incident.

7.2 US Coast Guard

The US Coast Guard has spill response equipment located in a trailer at the Coos Bay Air Station and the Pacific Strike Team will be mobilized in response to a spill.

Response activities will follow the Coos Bay Geographic Response Plan.

8 Maritime Security Conditions

There are no current maritime security concerns and there has been no increase in Maritime Security Levels since the implementation of the Maritime Transportation Security Act, (MTSA), in 2002 and Codes of Federal Regulation (CFR) that govern ship and facility security (33 CFR 101, 103, 104 and 105).

The Act and CFR's require that facilities that receive foreign flagged vessels greater than 100 gross tons (GT), cruise ships or facilities that handle certain dangerous cargos develop and implement a security plan to help deter criminal and terrorist activities. Each Facility Security Plan (FSP) will be reviewed and approved by the Captain of the Port (COPT) and the facility audited on an annual basis.

FIGURE 19 – M/V FLORA PIONEER DEPARTING ROSEBURG COOS BAY TERMINAL

There are three maritime security levels (MARSEC), with level 1 being the lowest and 3 the highest. Facilities normally operate at MARSEC level is level 1, but this can be increased to higher levels by the Captain of the Port based on the credibility and specificity of security threats to the area, leading to the possibility of port closure when at MARSEC Level 3.

While this Harbor Safety Plan addresses safety concerns, there may be issues between safety and security, where depending on the situation, one will take a secondary position to the other. An example of this is an increase in MARSEC level where the implementation of additional security measures may affect existing safety procedures or concerns, such as closing access/exit doors to restrict and better control unauthorized access to the facility, pier or ship.

It is important to be aware of this relationship in developing any new safety procedures or recommendations.

9 Vessel Traffic and Cargos

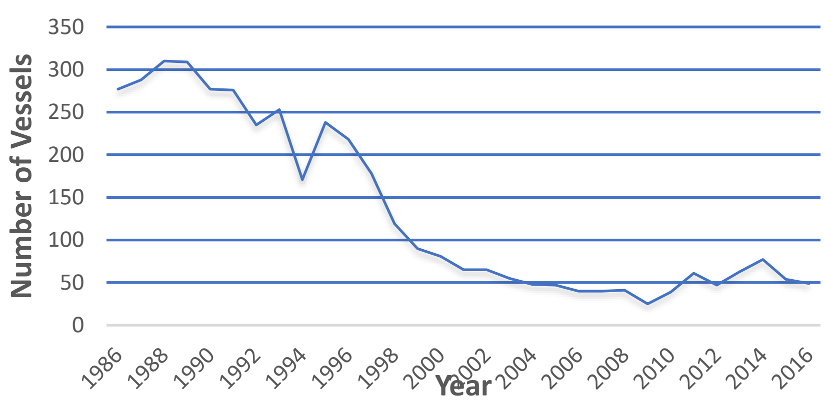
9.1 Commercial Vessels

Vessel cargo consists primarily of wood products and the number of large ships using the Coos Bay area has fallen off since the year 2000. During the past two years (2015-2016), a total of 100 ships have visited the Coos Bay Harbor complex. This equates to approximately one ship per week. While documented records were not available, tug and barge traffic has been approximately 200-400 per year.

Despite a continued drop in deep draft vessel calls since 1990, future projections indicate an increase in vessel arrivals into the port of Coos Bay.

Over the years, while the **number** of deep draft vessels typically calling on Coos Bay terminals has decreased, their size has increased from an average of 45,422 Metric Tonnes to an average of 52,894 Metric Tonnes with a projected near-term vessel size of 70,400 Metric Tonnes as seen in Appendix D.

TABLE 2 - VESSEL CALLS PER YEAR 1986-2016



This increase in vessel size creates its own set of safety concerns that the CBHSC should keep an eye on. Some of these concerns include:

- the suitability of the navigational channel (is the channel deep enough; are the turning basins large enough) and
- the maneuverability and responsiveness of these large vessels in a waterway with a projected increase in vessel traffic as well as
- the increase pollution potential of these larger vessels.

There are currently no issues that need attention from the CBHSC.

There are no vehicle or passenger ferries or cruise ships in or calling Coos Bay.

9.2 Commercial Fishing Vessels

The Coos Bay area was once a very large fishing area. Dungeness Crab, Chinook salmon are the primary commercial fisheries in Coos Bay with Albacore tuna and pink shrimp coming in second. The recent decline of the fisheries has diminished the fishing fleet, but the fleet still numbers some 85-100 vessels operating from the area. These vessels are both moored in the harbor as well as trailered to the marina for launching.

According to the US Coast Guard, in 2016, sixteen of the eighteen casualties involved commercial fishing vessels.

In addition to the commercial fishing fleet, there are five U.S. Coast Guard inspected passenger vessels which take customers out fishing during the season.

9.3 Recreational Boating

Recreational boaters are a safety concern in Coos Bay, as the operators do not always know the navigational rules of the road, keep a proper lookout or keep their boats in good operating conditions.

According to 2016 statistic collected and analyzed by the Oregon State Marine Board, the number one cause of fatal accidents this year was a 3-way tie of Force of Wave/Wake, Hazardous Waters and Operator Inexperience/Error with most of the accidents happening while crabbing/fishing and relaxing.

The US Coast Guard Auxiliary offers free vessel safety checks, boat safety training and reading material to help educate the recreational boating community regarding boating safety practices, rules of the road, Oregon boating laws and Coos Bay navigational hazards. Vessel Safety Checks are available by appointment in the Coos Bay, North Bend, Lakeside, Winchester Bay, Reedsport, and Bandon areas.

9.4 Vessel Traffic

This section provides a description of the procedures for routing vessel traffic, and any contingency or secondary routing plans which may be used during construction and dredging operations.

9.4.1 Vessel Traffic System

There is no Vessel Traffic System (VTS) in Coos Bay. The small amount of existing traffic is managed by the pilots. The larger vessels are generally handled a single ship at a time, which produces a one-way traffic pattern.

9.4.2 Notice of Arrivals

The National Vessel Movement Center (NVMC) was established to track notice of arrival information from ships entering U.S. ports. If a ship's voyage time is 96 hours or more, they must submit a Notice of Arrival (NOA) at least 96 hours before entering the U.S. port or place of destination. If a ship's voyage time is less than 96 hours, they must submit an NOA before departure, but at least 24 hours before entering the port or place of destination. This regulation applies to U.S. and foreign vessels bound for or departing from ports or places in the United States.

Notwithstanding the USCG requirement of 96 hours advance notice of arrival, the pilots request at least a 24-hour advance notice of arrival. This ensures they will be able to reach the pilot boarding station at the proper time, as well as advise the Master of the ship if there are potential delays in entering the harbor.

9.4.3 Vessel Routing

The risk of a grounding/collision generally increases the closer a vessel transits to shore. The higher risk areas were generally 25 nautical miles (nm) from land along the entire West Coast.

The West Coast of the United States has a voluntary agreement between the States, shipping companies, and the US Coast Guard. This agreement governs coastal traffic patterns. Using the Pacific States/BC Task Force Voluntary Routing Guide, tug and barges typically remain between 5-25 miles from the coast. Tank barges remaining at least 25 miles from the coast. Tank ships are obliged to stay greater than 50 miles from shore unless making port entry.

There is no specific or secondary routing for vessels transiting Coos Bay besides staying within the navigation channel as marked in NOAA Chart 18785 and following the Rules of the Road and the Law of Tonnage.

10 History of Accidents and Near Misses

This section reviews the history and types of all accidents and near-accidents which have occurred within the region during the past two years (2016-2017) and any corrective actions or programs taken to alleviate recurrences.

10.1 Statistics Year 2016

A total of 18 marine casualties were reported in 2016. Sixteen of the casualties involved commercial fishing vessels and included the following incidents: one (1) involved a grounding, one (1) involved a crewmember injury, three (3) involved vessel sinking and loss of life, described in the following section; three (3) involved loss of steering and eight (8) involved loss of propulsion. The other two marine casualties involved a crewmember injury onboard a bulk carrier and a reduction of propulsion onboard a tug.

10.2 Statistics Year 2017

A total of 6 marine casualties have been reported for 2017, as of July 7, 2017. Four of the casualties involved commercial fishing vessels and included three incidents of loss of propulsion and one incident with a loss of power. The other two casualties involved a loss of propulsion on an ATB (articulated tug and barge) and a crewmember injury onboard a bulk carrier.

10.3 Recent Accidents

Summary of recent accidents can be found in Appendix E.

10.4 Historical Accidents of Significance

10.4.1 Grounding of the M/V New Carissa

The M/V NEW CARISSA, a 639-foot bulk freight ship of Panamanian registry, was operated by TMM Co. Ltd., of Tokyo and owned by Green Atlas Shipping S.A. of Panama. On the night of 3 February 1999, there were 26 crewmen on board. The vessel carried no cargo, as it was inbound from Japan to pick up 37 thousand tons of wood chips at Coos Bay, Oregon. However, a strong ocean storm, with winds that reached 39 knots and seas up to 26 feet, was hitting the Central Oregon Coast that night. The Coos Bay pilot assigned to join the ship indicated that it would not enter the bay under those conditions and that he would join the ship the next day. During the storm, the ship dragged anchor and drifted towards shore. The crew tried to weigh anchor and move the ship, but during the early morning hours of 4 February, it went hard aground about 150 yards off a stretch of remote, undeveloped sandy beach three miles north of Coos Bay, Oregon.

The grounding of the M/V NEW CARISSA was unusual in that the ship became grounded twice, the response set a precedent by burning the ship's oil on board, and extraordinary means, including 69 rounds from a Navy destroyer and an MK-48 torpedo from a nuclear-powered submarine, were attempted to sink the ship in order to reduce the risk of a major oil spill.

The M/V NEW CARISSA casualty did not occur while entering or transiting Coos Bay. The vessel's master chose to wait out the storm at anchor instead of proceeding to sea and awaiting the pilot. Anchoring offshore has been restricted since this casualty.

10.5 Near Misses

According to the US Coast Guard, there have no records of near misses. This does not mean that they do not occur.

10.6 Loss of Propulsion/Steering

There is currently no guidance for vessels coming in and out that are having difficulty with steering/propulsion. Procedures will very much depend on how disabled the vessel is and its location in the Bay/ river.

Loss of Propulsion and Loss of Steering are reported to the US Coast Guard.

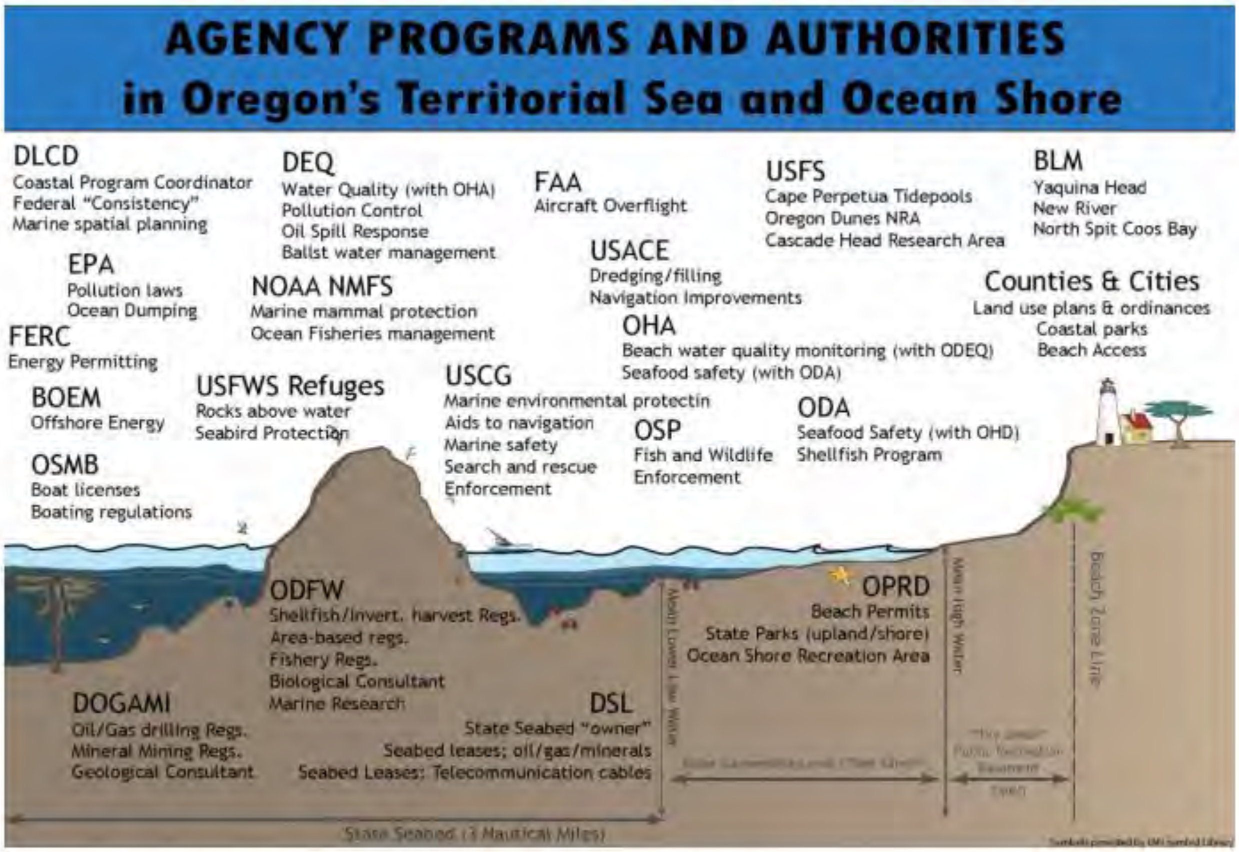
10.7 Corrective actions or programs

No corrective measures or programs have been taken or established by the CBHSC.

Boater education and information regarding weather and bar conditions continue to be distributed by the US Coast Guard, Coast Guard Auxiliary, Dungeness Crab Commission, NOAA and other agencies/entities.

11 Federal, State, And Local Agencies and Laws

As can be seen from the image below, many agencies have responsibility and authority over Oregon's territorial sea and ocean shore. However, of those listed only a few have jurisdictional authority and programs with direct impact on the maritime safety of the harbor.



Source: ODFW and Oregon Department of Land Conservation and Development (DLCD)

FIGURE 20 - JURISDICTIONAL AREAS OF OREGON AGENCY PROGRAMS AND AUTHORITIES

11.1 Federal Laws

The two Federal agencies with jurisdiction over the safety of Coos Bay Harbor are the US Coast Guard and the Army Corps of Engineers.

11.1.1 US Coast Guard (USCG)

The Captain of the Port has varying levels of jurisdiction extending to the outer limit (200 nautical miles) of the EEZ for foreign and domestic vessels.

The US Coast Guard has several lines of authority and program activities that relate to Oregon's territorial sea. The USCG (1) is the lead agency for oil-spill response and cleanup and is the on-scene coordinator for planning and response; (2) maintains search-and-rescue stations, including air stations at Warrenton (Astoria) and North Bend (Coos Bay); (3) has authority over buoys and markers to regulate vessel operations. The USCG has a program of routine Marine Environmental Patrols along the ocean shore to locate and ensure the safe removal of any hazardous materials or debris that may be washed ashore. The USCG is also responsible Harbor Security and Investigations of marine incidents and accidents.

- Regulations regarding vessel safety fall under Title 46 Code of Federal Regulations (CFR); Shipping
- Regulations regarding safe navigation and security fall under Title 33 CFR Navigation and Navigable Waters parts 1-199

11.1.2 Army Corps of Engineers (USACE)

The Corps is responsible for building and maintaining coastal navigational projects, including jetties, navigation channels, and navigational structures under the Rivers and Harbors Act (33 USC 401 - 709b and 2201 - 2329). Material dredged from coastal ports is frequently disposed in ocean waters at sites designated by the Environmental Protection Agency (EPA). Placement of dredged materials at these ocean sites is regulated under sections 102 and 103 of the Marine Protection, Research, and Sanctuaries Act (MPRSA) administered by the EPA or the Corps under section 404 of the Clean Water Act (CWA). The Corps also has permit authority over work performed by others in navigable waters under section 10 of the Rivers and Harbors Act, Section 404 of the CWA, and section 103 of the MPRSA.

- Regulations regarding navigation fall under Title 33 CFR Navigation and Navigable Waters parts 200-399

Other Federal Agencies with jurisdiction over the maritime interests are listed in Appendix F.

11.2 State

11.2.1 Department of State Lands

The Department of State Lands is responsible for management of publicly owned submerged and submersible land. The public has rights to use the beds and banks of navigable waterways for any legal activity, such as boating, fishing, and swimming. The following are typical uses of state-owned submerged and submersible lands:

- Houseboats
- Boat ramps
- Docks, floats, and wharfs
- Marinas and moorages
- Marine industrial facilities
- Bridges
- Utilities and pipeline crossings
- Sand and gravel operations
- Remedial cleanup
- Non-water dependent commercial uses (restaurants for example)

Any of the uses described above require an authorization from the Department of State Lands. Authorizations include leases, licenses, easements, registrations and short-term access agreements. The Department of State Lands also issues two types of permits and authorizations:

- Removal-fill permits for removal or fill activity in waterways and wetlands
- Proprietary waterway authorizations for use of state-owned waterways

11.2.2 Department of Environmental Quality

Oil Spill Contingency Planning Act (ORS 468B.300) requires an oil spill prevention and emergency response plan approved by the Department of Environmental Quality prior to the operation of onshore or offshore oil or gas facilities or operation of tanker, cargo, or passenger vessels in state waters of the Pacific Ocean, estuaries to the head of tide water, the Columbia River, and the Willamette River to Willamette Falls. This act includes legislative policy, provides the DEQ with authority to adopt standards for preparing contingency plans, and lists minimum requirements for such contingency plans. The act establishes an Oil Spill Prevention Fund, creates an Oregon coast safety committee, and establishes a wildlife rescue training program.

11.3 Local Laws

There are currently no local laws in effect that pertain to ports safety.

11.4 Existing and proposed Laws and Regulations

Review of existing and proposed federal, state and local laws, regulations or ordinances affecting the region to determine a need for any change;

11.4.1 Change to state pilotage laws

House Bill 2695 does not require local knowledge for tugboat operators. The Pilots are working with the US Coast Guard to make sure this is not the case and that some local knowledge is in place. Tugs sailing under registry from Canada to Coos Bay only are not required to take a state licensed Pilot.

12 Educational Needs

An assessment of the need for establishing or upgrading existing educational or public awareness programs for all waterway users.

12.1 Seasonal and Recreational Boaters

The Coast Guard reminds boaters to adhere and pay attention to bar restrictions while traveling rivers in the area. Deaths in bar-related accidents have been reported along the coast of Oregon each year. Failure to comply with rules and regulations could result in financial penalties, imprisonment, and forfeiture of the owner's vessel and equipment.

Boaters should check weather reports and ensure they have the proper safety and communication equipment before getting underway. To check local bar conditions, call the nearest Coast Guard station or tune the radio to 1610 AM. For up to date bar status or restrictions visit:

http://www.wrh.noaa.gov/pqr/marine/bars_mover.php[3]

While information is provided to the community, accidents still happen. The CBHSC recognizes the need for additional education and outreach programs to both the recreational and commercial boating community.

[3] United States Power Squadron, Coos Bay website http://www.usps.org/lc/coos/page3.html

13 Communications

13.1 Current ship-to-ship and ship communication

Radios:

- The USCG monitors channel 16
- The USCG provides notice to mariner, navigation safety update on channel 22A
- The pilot boats monitor VHF-FM channels 13 and 16 and use channels 12 and 18A as working frequency.
- Tugboats over 26' in length are subject to the Bridge to Bridge Radio act and required to monitor Channel 16 (distress) and Channel 13 (communications). In Coos Bay, towboat operators primarily work 7A followed by 65. The Pilots work 18A.
- Coos County Sheriff boats use and monitor channel 16 when underway.

Cellular Phones:

- The use of cell phones/texting devices and phone applications aboard US Coast Guard boat force assets is not authorized without the permission of the coxswain. At no time will the operator of the boat use a cell phone or texting device.
- Cell phones are not used on the bridge by Pilots.

13.1.1 Current ship-to-shore communication systems used in the region

- Radios – VHF marine band
- Cellular Phones

13.2 Low propagation, or silent areas within the region

There are currently no low propagation or silent areas, however,

- Channel use is busy during fishing season and causes Pilot to change channels.

13.3 Strategy to address communication deficiencies.

There are currently no deficiencies that need to be addressed by the Harbor Safety Committee.

14 Bridge User Requirements

This section includes an assessment of current schedule for bridge openings, the adequacy of the ship to bridge communications and the physical limitations affecting vertical and horizontal clearances.

14.1 Rail Bridge

According to 33 CFR 117, the draw of the Port of Coos Bay railroad bridge, mile 7.5 at North Bend, shall be maintained in the fully open position, except for the crossing of trains or maintenance.

14.1.1 Schedule:

The trains do not follow a regular schedule due to the lack of demand. This is why there is no published schedule for when the Rail Bridge will be closed.

14.1.2 Communications

Bridge tenders only monitor the radio when they are on duty when a train is passing. At times, Pilots sometimes have difficulty reaching the bridgetenders on the radio and have to resort to using the landline, or the duty cell number.

Alternatively, if the Pilot cannot get hold of bridgetender, the Pilots will ask the tugs to verify the position of the bridge for them.

14.1.3 Clearances

As previously mentioned, vessels following the Upper Jarvis Range light will have to be aware of their proximity to the middle span of the open rail bridge.

15 Best Maritime Practices - TBC

15.1 Background

Best Marine Practices (BMPs) are not to be confused with regulations as they have no legal status. Instead, they provide guidance by the HSC to the maritime community on how a prudent mariner would proceed under specified circumstances. BMPs are clear and concise, as well as easily-accessed and understood by the mariner. It is hoped that such practical, hands-on safety measures will have broad appeal in the maritime community and reduce personnel, vessel and environmental casualties while facilitating the flow of maritime commerce.

Below are Best Maritime Practice “BMP” Guidelines[4]:

BMP should “NOT” be considered as follows:

1. A regulation, enforced by a regulatory agency
2. An underground regulation–it cannot be enforced by any regulatory agency

BMP should be considered as follows:

1. A common-sense measure or practice that would normally be employed by a prudent mariner
2. A useful tool that promotes safety and adds value and is not an exercise in generating paper
3. The result of “brainstorming at the grassroots level” by each HSC
4. An improved process or procedure that may originate as a recommendation from the HSC
5. “Best Maritime Practice” is an accepted and agreed upon method to conduct an operation or process that will enhance safety for vessels, personnel, dockside facilities and marine resources
6. A good example of a “Best Maritime Practice” would be the San Francisco and Los Angeles/Long Beach Harbor Safety Committees’ recommended procedure with respect to bunker barge transfer operations while alongside containers vessels at terminals.
7. Include as a disclaimer that the “BMP” is not in conflict with nor do they replace existing regulations which are already in place

15.2 The BMP Process

1. Once a “BMP” is developed it should be communicated to members of the harbor community in one of or all of the following manners
   a. Incorporated into related procedure manuals or references made to the particular “BMP”
   b. Posted on the Port of Coos Bay web page for the public at large
   c. Distributed in the form of brochures
   d. Referenced in the “Coast Pilot” as appropriate
2. “BMP” should also be included in the Committee’s Harbor Safety Plan

[4] The California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) presented these guidelines to the California Harbor Safety Committees at their Summit on 11/3/2009

3. "BMP" should be reviewed or revisited annually to determine if they can be improved upon, or even discontinued as the case may be

15.2.1.1 Coos Bay Best Maritime Practices

BMP's adopted by the CBHSC are included in Appendix G.

16 Monitoring & Plan Enforcement

This section includes suggested mechanisms that will ensure that the provisions of the plan are fully, uniformly and regularly enforced.

The Committee developed guidelines for vessels operating in this region to ensure safe, reliable, and environmentally sound marine transportation. Although the Committee cannot enforce these guidelines under state, federal, or local law, they institutionalize sound marine operating practices as Standards of Care that responsible vessel operators follow voluntarily. The Committee depends on its members, local, state, and federal agencies and the maritime community to monitor compliance with the Standards of Care.

Observed violations or deviations from this Plan should be referred to the Committee, Coast Guard, or State or local authorities for evaluation and possible enforcement under applicable federal and state law or regulation. If the Committee finds significant deviations, it will evaluate and may recommend more stringent enforcement, and, as appropriate, state, federal, or local rulemaking.

The following briefly summarizes Plan provisions requiring enforcement and the parties who directly monitor compliance. State and/or federal regulations cover some Plan sections discussed below, while others are guidelines.

1. Aids to Navigation: Federal regulations control all Aids to Navigation. Report any problems to the Coast Guard.

2. Anchorages: Federal regulations control anchorages. Pilots and Coast Guard normally monitor compliance with anchorage requirements. Violations are to be reported to the Coast Guard.

3. Harbor Depths, Channel Design, and Dredging: Federal law and regulations govern the harbor depths and dredging. Report any problems to the U.S. Army Corps of Engineers or port authorities.

4. Contingency Routing: Pilots and the Coast Guard monitor compliance, which the Coast Guard enforces. Violations are to be reported to the Coast Guard. Appendix H is a placeholder for the Coast Guard directive for emergency dispersal.

5. History of Accidents and Near Misses in the Harbor: This chapter’s provisions are maintained by the Coast Guard and the Oregon Marine Board. Questions or concerns may be directed to them.

   Oregon:
   Oregon responsibilities of a boat operator at an accident scene: (ORS 830.475, 830.480, OAR 250-010-0110). Anyone involved in a boat accident must give name, address, other required information and aid to injured person(s), including transportation to a hospital if treatment appears necessary or is requested by injured person(s).

• Leaving a boat accident scene before performing operator's duties is a Class C felony punishable by five years in jail and/or a $100,000 fine.
• Boat operators involved in an accident resulting in death, injury or property damage exceeding $2000 must report the accident to the State Marine Board on a Marine Board Accident Report Form:

–within 48 hours of an accident resulting in death or injury;
–within 10 days of an accident causing property/equipment damage only.

Occupants are responsible for making accident report when the operator is physically incapable of doing so.

In the case of immediate need of assistance, waterway boaters should call 911.

US Coast Guard:
Under the general marine casualty reporting provisions of 46 C.F.R. part 4, the owner, operator, or person in charge of a vessel must report marine casualties involving a grounding, allision (a moving vessel hitting a fixed object), or loss of propulsion that impacts the maneuverability of the vessel, impacts the vessel's seaworthiness, or fitness for service or route, loss of life, injury requiring professional medical treatment, property damage in excess of $35,000, or significant harm to the environment. 46 C.F.R. § 4.05-1.

The initial report must be made immediately by telephone to Sector Columbia River Investigations Department at 503-861-2242, followed by a written report (Form CG-2692), within five days of the marine casualty. This report must include any necessary alcohol or drug testing required by the regulations,

6. Communications: This Chapter mandates that highest quality communications standards are used in Coos Bay Harbor. Discipline programs reducing congestion, interference, unnecessary/ excessive use of high power settings, and frequency misuse. All radio users in the harbor area, as well as Committee members, can help the Coast Guard, the Oregon Department of Fish and Wildlife, and the Federal Communications Commission (FCC) monitor these standards. Violations are to be reported to the FCC and to the Harbor Safety Committee.

   Waterway users can file complaints with FCC using an online complaint form. You can also file a complaint by calling 1-888-CALL-FCC (1-888-225-5322) voice, 1-888-TELL-FCC (1-888-835-5322) TTY; faxing 1-866-418-0232, or writing to:

   Federal Communications Commission
   Consumer & Governmental Affairs Bureau
   Consumer Inquiries and Complaints Division
   445 12th St., SW
   Washington, DC 20554.

You can help FCC resolve your complaint more quickly by providing as much of the following information as possible:
(1) the date and time the material was aired;
(2) the call sign, channel, or frequency of the station;
(3) the city and state where the complaint occurs; and
(4) as many details as possible about the content of the broadcast to help the FCC determine whether the material was improper. It is also helpful to include your address, e-mail and phone numbers.

7. Bridges: Federal regulations govern bridge operations. Improper bridge management incidents are to be reported to the Coast Guard District 13 Bridge Management Section (800) 982-8813 or to Sector Columbia River, Waterway Management Division at 503-861-2242.

8. Small Craft: The main small vessel potential safety problem is a violation of the U.S. Inland Navigation Rules (1980), Rule 9: impeding the progress of large vessels within channels. Pilots and the Coast Guard monitor compliance with Rule 9. Recreational boat navigation violations are to be reported to the Coast Guard or any readily available local law enforcement authority including the Coos County Sheriffs.

9. Tug Escort/Ship Assist: There is currently no tug escort and/or ship assist regulatory requirements for Coos Bay harbor. The USCG and the Pilots have the authority to require escort and ship assist vessels on a case by case basis.

10. Pilotage: Pilots should remain in service on inbound vessels until they reach safe berth and on outbound vessels until 1mile past K buoy. The US Coast Guard and pilots monitor compliance. Report any deviations from the standard procedures or Standards of Care of this Plan made by pilots or other vessel operators to the Committee or Coast Guard.

11. Under-keel Clearance and Inclement Weather: Pilots to monitor for compliance. Violations are to be reported directly to the Coast Guard. Report violations regarding reduced visibility to USCG.

16.1 Enforcement Authorities

The Committee formally requests that its members, as well as all agencies with enforcement and monitoring authority within the scope of the Plan, monitor compliance with Plan guidelines and provisions. Furthermore, it is very important that members of the local maritime community, who regularly conduct business in the harbor area and have the strongest presence, assist in monitoring by acting as the eyes and ears of the Committee. Please report infractions of Plan guidelines, violations of state and federal regulations and any unsafe practices to the following bodies, as appropriate:

1. The Coast Guard - 24/7 Command Duty Officer: Violations of federal regulations or Plan guidelines, and unsafe practices

- (503) 861-2242

3. The Coos County Sheriff Marine Division: Violations of state laws, local ordinances;
   - (541) 396-7830
4. Oregon Department of Fish and Wildlife: NON- EMERGENCY notifications for violations of state regulations;
   - (503) 947-6000
5. Department of Environmental Quality: Violations of state law governing oil transfers at marine facilities;
   - (800) 452-4011

The Committee encourages the local maritime community and agencies that monitor regulatory compliance to notify the Committee of marine safety and environmental concerns by email at Coosbayharborsafety@gmail.com or attending the regular monthly meetings and make a report to the Committee.

Should the Committee find that Plan guidelines are not routinely followed, it will evaluate more-stringent approaches to enforcement, including, as appropriate, state, federal, and local rulemaking

17 CBHSC Recommendations and Accomplishments

17.1 Recommendations

The CBHSC has submitted recommendations to the community. These can be found in Appendix I of the plan.

17.2 Accomplishments

The CBHSC has accomplished the following:

- FAA review of the vessel transit height restriction and agreement that aircraft movements will be controlled to allow the safe passage of vessels with an air draft greater than 144 feet.
- Distribution of thumb drives to the towing and crabbing community with charts/plots showing the designated tow lanes and the crabbing areas to help both avoid operating each other's areas.

18 Implementation of CBHSC Action Items

Action items derived from Harbor Safety Committee meetings will be reviewed by the committee and assigned to an individual or to a subcommittee to execute within a given time frame.

Action Items and their status are tracked in the table found in Appendix J.

19 Applicable Regulations and Guidelines

USCG Ports and Waterways Safety Regulations, 33 CFR Subchapter P

- Part 160 Ports and Waterways General
- Part 162 Inland Waterways Navigation Rules
- Part 163 Towing of barges
- Part 164 Navigation Safety Rules
- Part 165 Regulated Navigation Areas
- Part 169 Ship Reporting Systems

USCG Pollution Regulations, 33 CFR Subchapter O

- Part 151 Vessels Carrying Oil, Chemicals, Garbage, and Ballast Water
- Part 153 Control of Pollution
- Part 154 Facilities Transferring Oil or Hazardous Material in Bulk
- Part 155 Oil/Hazardous Material Pollution Prevention Regulations for Vessels
  - Non-Tank Vessel Contingency Plan Regulations
  - Tank Vessel Contingency Plan Regulations
  - Salvage and Marine Firefighting
- Part 156 Oil/Hazardous Material Transfer Operations
- Part 158 Reception Facilities for Oil, Noxious Liquid Substances, and Garbage
- Part 159 Marine Sanitation Devices

USCG Maritime Security Regulations, 33 CRF Subchapter H

- Part 101 General
- Part 103 Area Maritime Security
- Part 104 Vessel Security
- Part 105 Facility Security

Guidelines for Under Keel Clearance in Coos Bays is on average 10% and is established by each vessel in consultation with the pilots.

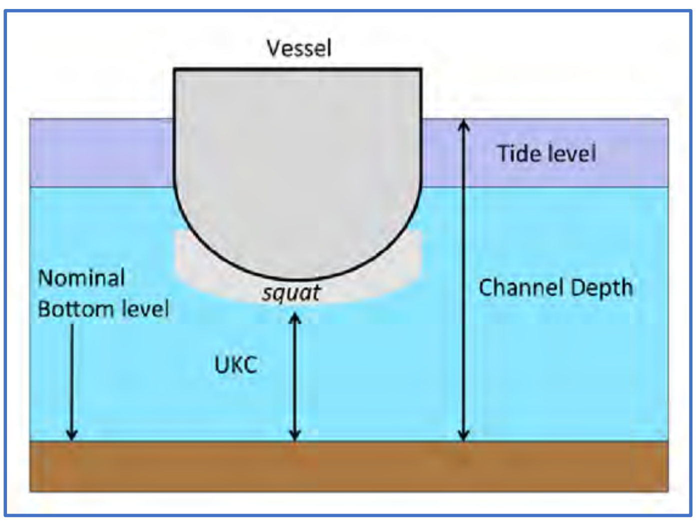


FIGURE 21 - UNDER KEEL CLEARANCE (UKC)

20 Funding

This section shall provide recommendations for funding projects that the committee intends to recommend or initiate; and consider the imposition of user fees, and assess existing billing mechanisms as potential funding sources.

There are currently no projects the committee would like to see funded nor are user fees or other mechanisms used to generate funding being considered at this stage.

21 Competitive Aspects

This section shall identify and discuss the potential economic impacts of implementing the provisions of the harbor safety plan and describe the significant differences in the restrictions that could vary from port to port within the region.

There are currently no identified economic impacts brought about by the implementation of the recommendations of the harbor safety plan, nor does the plan impose any additional restrictions that would render Coos Bay less favorable as compared to other ports in the area.

22 APPENDICES

Appendix A - Coos Bay Harbor Safety Committee Charter

Separate Document

Appendix B - Contact Information for Coos Bay

Separate Document

Appendix C – ATON review

Separate Document

Appendix D - Historical Vessel Statistics

Separate Document

Appendix E – Recent Accidents

Separate Document

Appendix F – Federal Agencies and Jurisdictions

Separate Document

Appendix G – Best Marine Practices

Separate Document

Appendix H – US Coast Guard Regulations, Directives, Advisories, NVICS

Separate Document

Appendix I– List of Recommendations presented to the Community

Separate Document

Appendix J– List of Action Items

Separate Document

Appendix K– U.S. Coast Guard Waterways Analysis and Management

Separate Document

Appendix L– Annual Plan updates and changes

Separate Document

Exhibit 32

Coos Bay Channel Entrance

Distances and Buoy Markings.

Taken from Google Earth
(Buoys visually found and marked)

Entrance to Coos Bay Harbor / Charleston Marina / Barview & Cape Arago Hwy (Buoys marked)

Red Buoy to Shore .20 miles (1056 feet) (352 yards) (321.87 meters)
****

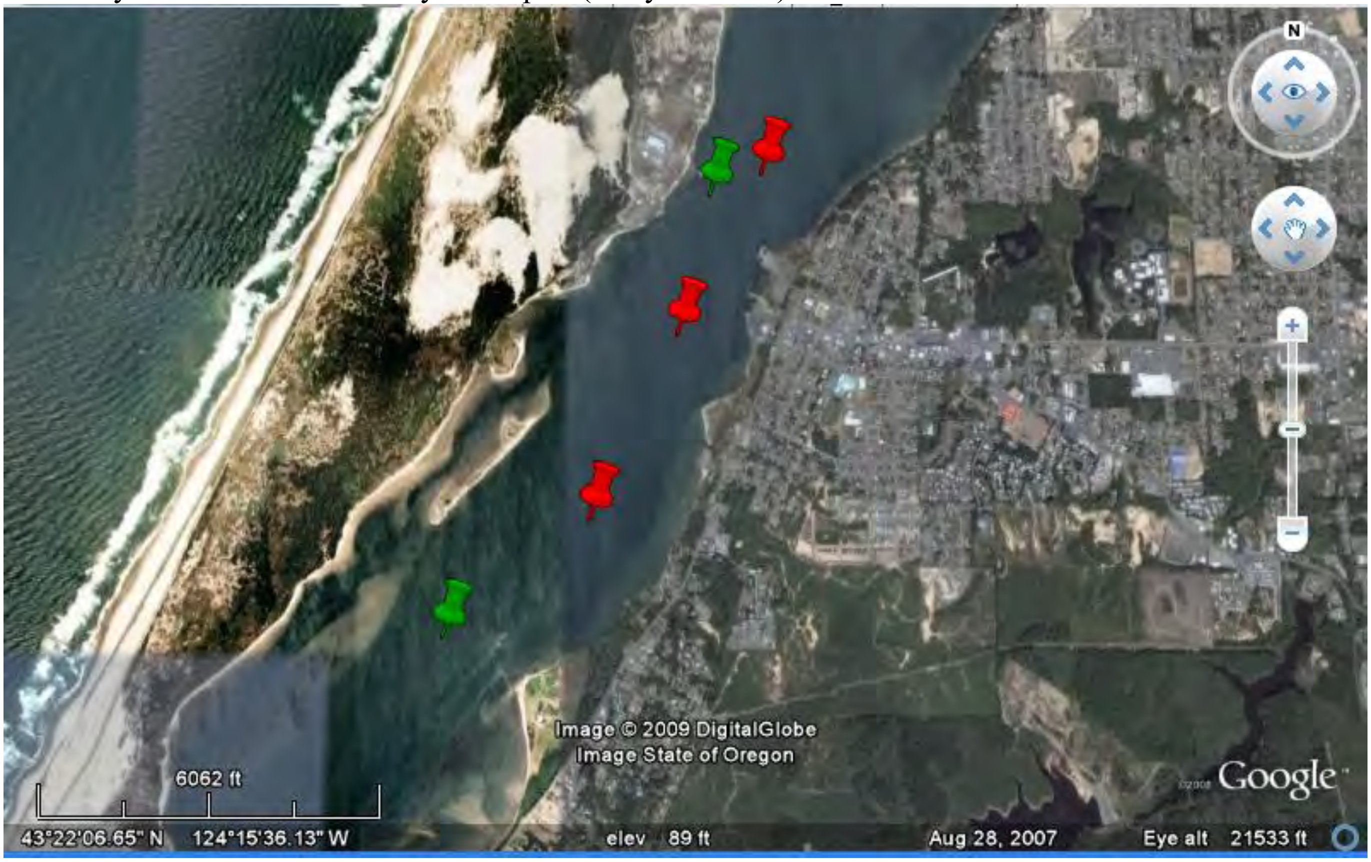
Red Buoy to shore .07 miles (369.6 feet) (123.2 yards) (112.65 meters)
****

Red Buoy to OIMB Auditorium .14 miles (739.2 feet) (246.4 yards) (225.31 meters)
****

Red Buoy to Coast Guard Housing Complex -.23 miles (1214.4 feet) (404.8 yards) (370.15 meters)
****

Red Buoy to House Along Cape Arago Hwy .34 miles (1795.2 feet) (598.4 yards) (547.18 meters)
****

Coos Bay Channel at Community of Empire (Buoys marked)

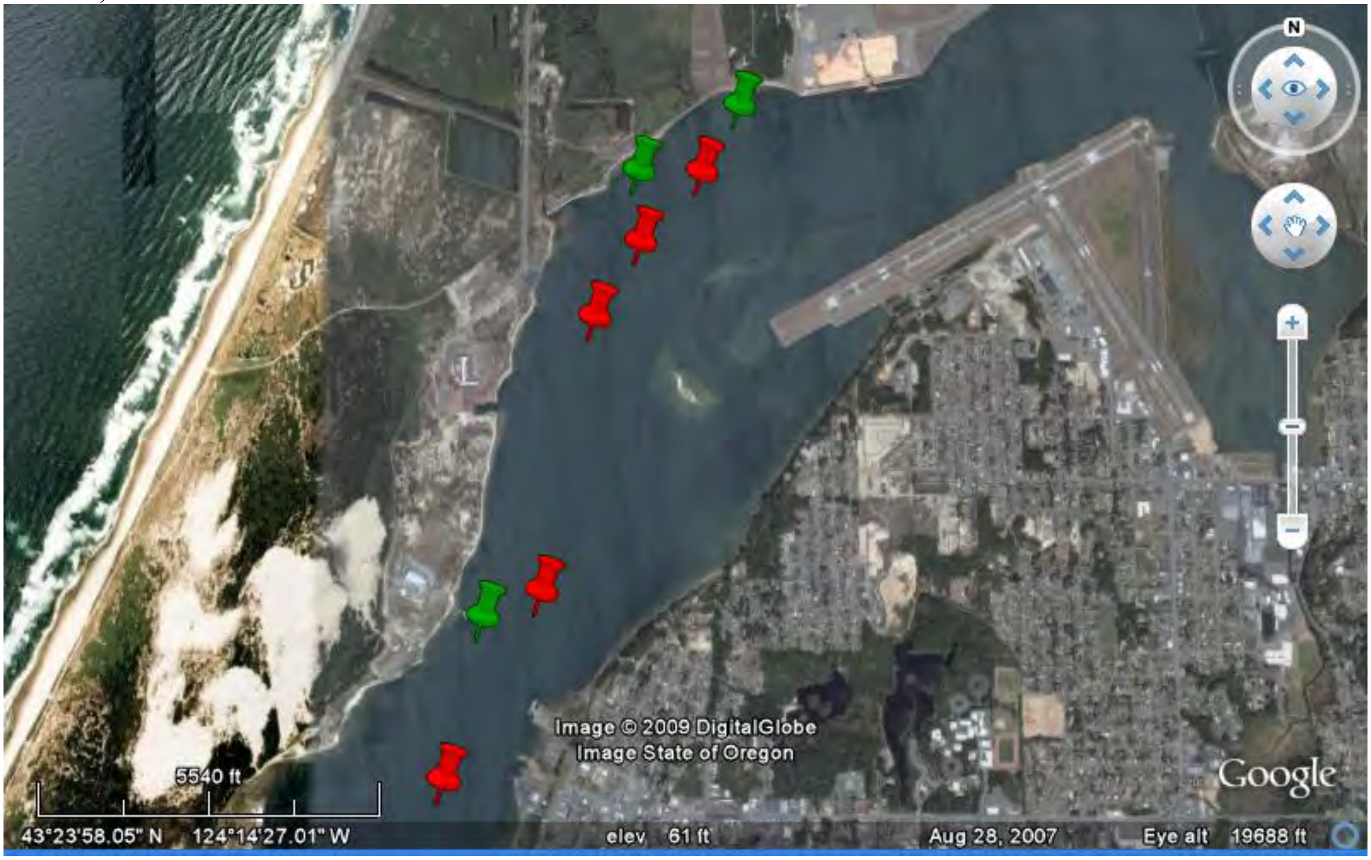


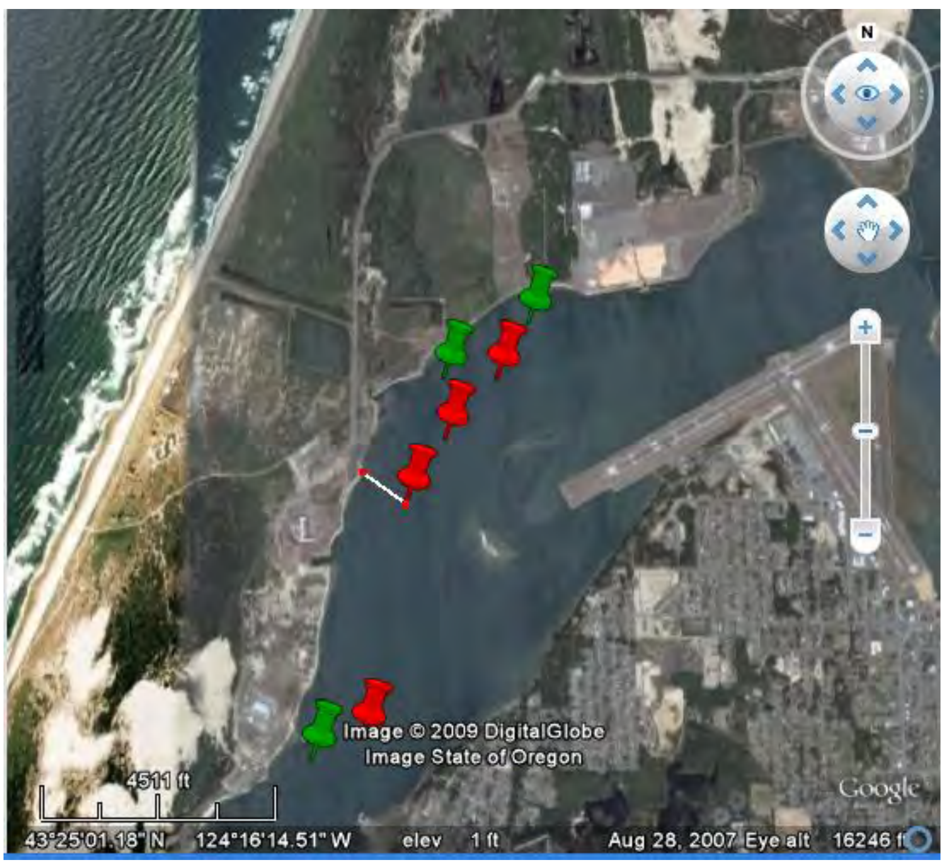
Red Buoy to Shoreline near DB Western .25 Miles (1320 feet) (440 yards) (402.34 meters)
****

Green Buoy to Shoreline near DB Western .12 miles (633.60 feet) (211.2 yards) (193.12 meters)
****

Red Buoy to Empire Marina Parking Lot - .25 Miles (1320 feet) (440 yards) (402.34 meters)
****

Coos Bay Channel – Jarvis Turn / Airport / City of North Bend / Industrial area on North Spit (Buoys marked)





Red Buoy to end of North Spit Boat Ramp .20 miles (1056 feet) (352 yards) (321.87 meters)

****

Red buoy to end of airport runway - .78 miles (4118.4 feet) (1372.8 yards) (1255.29 meters)
****

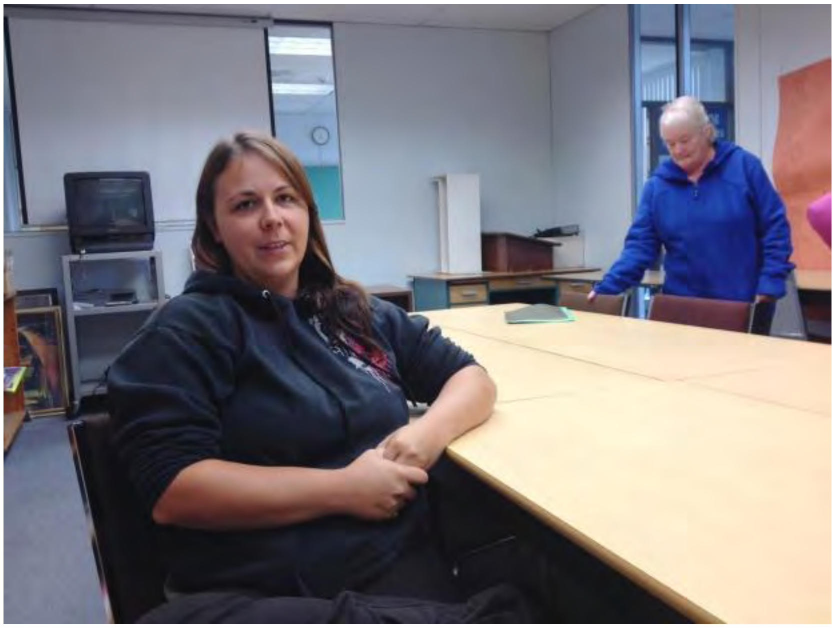
Exhibit 49

http://www.vancouversun.com/business/energy/Northwest+boom+already+bust+some/10326811/story.html?__lsa=0882-6c5e

Northwest B.C.’s LNG boom is already a bust for some (with video)

Heated economy drives up prices and drives out tenants

By Gordon Hoekstra, Vancouver Sun November 5, 2014



Oct. 1 - Kitimat - April Roy is one of the residents in Kitimat that have been evicted from apartments slated for renovation in anticipation of a economic boom from proposed LNG projects. Roy and her three children had been living in the Kuldo Apartments, but has had to move. As a result, her rent has increased significantly.
Photograph by: Gordon Hoekstra , Vancouver Sun

KITIMAT — In an ironic twist, April Roy moved to Kitimat five years ago from Fort McMurray to escape the high rents.

She found a three-bedroom apartment for $522, but then as a construction boom fuelled by the prospects of liquefied natural gas projects heated the local economy, the Kuldo Apartments were bought by Calgary-based Kiticorp and renovated.

She was evicted last year and had to find other accommodation.

Roy did, but at $1,200 for a cramped two-bedroom. She was only able to make the rent because she has a partner now, she said.

“That’s the only reason we managed it, or we would have been out on the streets,” she said.

The story is not a new one.

The recipe is simple: large industrial projects bring in thousands of workers and, combined with speculation, housing prices and rents are driven up.

It’s been played out in places such as Fort McMurray in northern Alberta and in Fort St. John in northeastern B.C.

The first recent wave of workers to northwest B.C. came with Rio Tinto’s $4.8-billion modernization of its aluminum smelter scheduled to be finished next year, and the $736-million Northwest Transmission Line, completed three months ago.

The next wave is meant to tap into Asia’s thirst for energy.

Petronas, Shell and Chevron, whose proposed LNG projects total more than $30 billion, would require as many as 16,000 workers.

While camps have been built to accommodate workers, some of them have spilled out into the communities, particularly when they have been given hefty living-out allowances.

In Kitimat, housing prices and rents have as much as tripled. Prices and rents are also up significantly in Terrace, the region’s service hub, and are rising in Prince Rupert as well.

In Kitimat, rental vacancy rates were 35-40 per cent three years ago, but they are now approaching zero.

While the rejuvenated housing market has meant new investments to improve the rental housing stock in northwest B.C., it has displaced hundreds of people on low and fixed incomes, say housing advocates.

Kitimat housing resource worker Paul LaGace says more low-income housing is needed from the province.

But that’s not the answer, says the B.C. Liberal government.

Let the market react to the influx of people and increasing wages, and where necessary assist people with rent subsidies where they are already living, says Natural Gas Development Ministry Rich Coleman, who has responsibility for housing.

LaGace says the so-called “renovictions” number in the hundreds.

Some renovations are legitimate, but sometimes landlords are simply using it as a ruse to get people out, slapping up a coat of paint and new carpets to charge higher rents, he said.

The problem is that with little government low income housing in Kitimat, and rising rents in Terrace and Prince Rupert, there are few options for people, said LaGace.

They have placed some people in Terrace, but sometimes they have little choice but to tell people to move to another town, perhaps trying to see if they have family elsewhere, he said.

“It’s a bad situation,” said LaGace.

In Prince Rupert, where a pair of LNG projects are proposed, the same problems are starting to emerge.

Ulf Kristiansen, with the Prince Rupert Unemployed Centre Society, said he believes a big increase in evictions is tied to an early influx of construction workers for LNG projects.

The annual allowable rent increase is about two per cent for existing tenants, but if you get a new tenant you can charge more. “Landlords are looking for any excuse to evict people so they can charge one-and-a-half times to double the rent,” he said.

At a mobile home park in Port Edward, just 10 minutes from Prince Rupert and adjacent to the proposed $11-billion Pacific Northwest LNG project led by Petronas, tenants were served eviction notices in August.

The tenants and are trying to fight the evictions.

Park resident Ken Jennings said he believes the new owners are simply trying to capitalize on the coming LNG boom at the expense of longtime park residents.

Jennings, 76, said he has no idea where he and his wife, Mary, 78, who are paying just over $200 for pad rent, will go.

“What a way to treat seniors,” he said.

Stonecliff Properties president Victoria Beattie said she bought the park as an investment.

She said she planned to fix the sewer and water system in the park, fill in empty spots with new trailers but keep some spots low rent, and potentially expand the park.

But Beattie says she has been stymied by the tenants, and has decided simply to close the park, as it will cost less than keeping it open.

In Kitimat, Kiticorp makes no apologies for its investment in the Kuldo apartments.

Nearly half of the 80 units were shuttered because it was cheaper for the previous landlord to turn off the heat and other services, given the low rents, says Kiticorp president Eli Abergel.

He also make no secret of their effort to benefit from the construction boom.

“It’s obviously inevitable that some of our tenants were displaced. But we still have some tenants paying very, very low rent that we still keep in our units. So, it’s all about balance for us,” he says.

Abergel also said that ultimately it’s the community and provincial government’s responsibility to deal with any need for low-income housing.

Chevron, which has not made a final investment decision on its Kitimat LNG project, said that displacing people on low and fixed incomes is a concern.

Rod Maier, a Chevron spokesman for the Kitimat LNG project, said the company does not want to create negative impacts in communities where it develops projects, which is why it tries to hire local as much as possible and will set up a 3,000-person worker camp if the project goes ahead.

Chevron has just completed a 600-person camp in Kitimat.

But Maier noted that sometimes the influx of workers and knowledge of living expense allowances will drive rents up on their own, noting that happened in Saint John's, Nfld., with the development of the Hibernia offshore oil project.

Stacey Tyers, a Terrace city councillor and poverty law advocate for the Terrace and District Community Services Society, says the biggest problem is the living-out allowance provided to workers.

At $130 a day, three workers can share a house and still pocket money, but it completely prices out the average home renter, she said.

And in a service centre such as Terrace, there are many retail workers who simply can't afford the doubling in rents for a two-bedroom place that now range from $1,200 to $1,500.

Between December and February last year, elementary schools in Terrace lost 60 children because their families couldn't afford to live in the community, she said.

The City of Terrace has taken steps to allow secondary suits in all areas, and is also in the midst of passing bylaws to allow carriage houses, reduce lot sizes and house sizes.

But low-income housing is the first solution, said Tyers.

"We keep explaining to the provincial government that housing is actually a barrier to our economic growth because we can't have businesses open here if their employees have nowhere to live," said Tyers.

Coleman, who has the housing portfolio, said the province is working with northwest communities to address the issues of increasing rents.

But Coleman noted that it is a natural phenomena: any time there is economic growth, there is going to be a change in the housing market.

He noted there had been a real problem with a depressed housing market in northwest B.C. for a long time, which has meant that very little new housing has hit the market.

"We wouldn't build social housing to fill the gap — we would actually let the market do that," he said.

Coleman is a proponent of increasing densities, adding carriage houses and increasing basement suites.

Add to that subsidized rents for those that need it where they are living and you create a quicker, more flexible solution, he said.

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Exhibit 50

http://www.cbc.ca/news/canada/british-columbia/b-c-lng-work-camps-concern-for-northern-towns-say-mayors-1.2938393

B.C. LNG work camps concern for northern towns, say mayors

Two northern B.C. mayors share their city's struggle with the impending influx of temporary workers

By Radio West, CBC News Posted: Feb 02, 2015

With promises of an LNG boom and Site C on the horizon, some B.C. communities are grappling with how to cope with the prospect of hundreds of workers arriving on their doorstep.

Two northern B.C. cities have already begun to deal with the issue. In Kitimat, two work camps are being built within city limits. Fort St. John will soon decide if it will allow the same thing.

"There's no doubt the people in that neighbourhood and the affected neighbourhood were not thrilled about it," said Kitimat mayor Phil Germuth.

Germuth said he voted against one of the work camp proposals because he didn't feel like there had been enough consultation with the residents of the neighbourhood where it is being built.

"I'm not saying you can't put a camp in a residential neighbourhood," said Germuth. "But if you're going to do it you really owe it to the people who are going to be affected by it, in my opinion, that they need to be consulted greatly with their concerns."

The proposal, a camp that will house 2,000 workers from any company willing to rent it, did get accepted by council. To ensure a legacy from the project, the city decided to charge a one-time tax of $500 per bed, which will go towards future affordable housing projects.

The idea of legacy is important to city of Fort St. John as well.

"Our top priority, as any community in the north," said Fort St. John Mayor Lori Ackerman, "is the development of vital permanent sustainable communities that provide the citizens with a high quality of life."

Ackerman said the buildings could house seniors or serve as affordable housing when they're eventually vacated.

She said the city is concerned about the impact on services such as health care, police and social welfare. Residents were also worried about traffic.

As a result of those concerns, the city has commissioned research on the potential impact of the camps. The results should be in to council in about two or three months.

"We're going to have to talk about community engagement at that point," said Ackerman.

Exhibit 69

https://theworldlink.com/news/science/where-have-the-wild-birds-gone-study-counts-billion-fewer/article_a626eed1-2063-52e5-9e5e-a6c7a903f593.html

Where have the wild birds gone? Study counts 3 billion fewer than 1970, stunning scientists

By Seth Borenstein and Christina Larson AP Science Writers
Sep 19, 2019

FILE - This April 14, 2019 file photo shows a western meadowlark in the Rocky Mountain Arsenal National Wildlife Refuge in Commerce City, Colo. According to a study released on Thursday, Sept. 19, 2019, North America's skies are lonelier and quieter as nearly 3 billion fewer wild birds soar in the air than in 1970. Some of the most common and recognizable birds are taking the biggest hits, even though they are not near disappearing yet. The population of eastern meadowlarks has shriveled by more than three-quarters with the western meadowlark nearly as hard hit. (AP Photo/David Zalubowski, File)
David Zalubowski

North America's skies are lonelier and quieter as nearly 3 billion fewer wild birds soar in the air than in 1970, a comprehensive study shows.

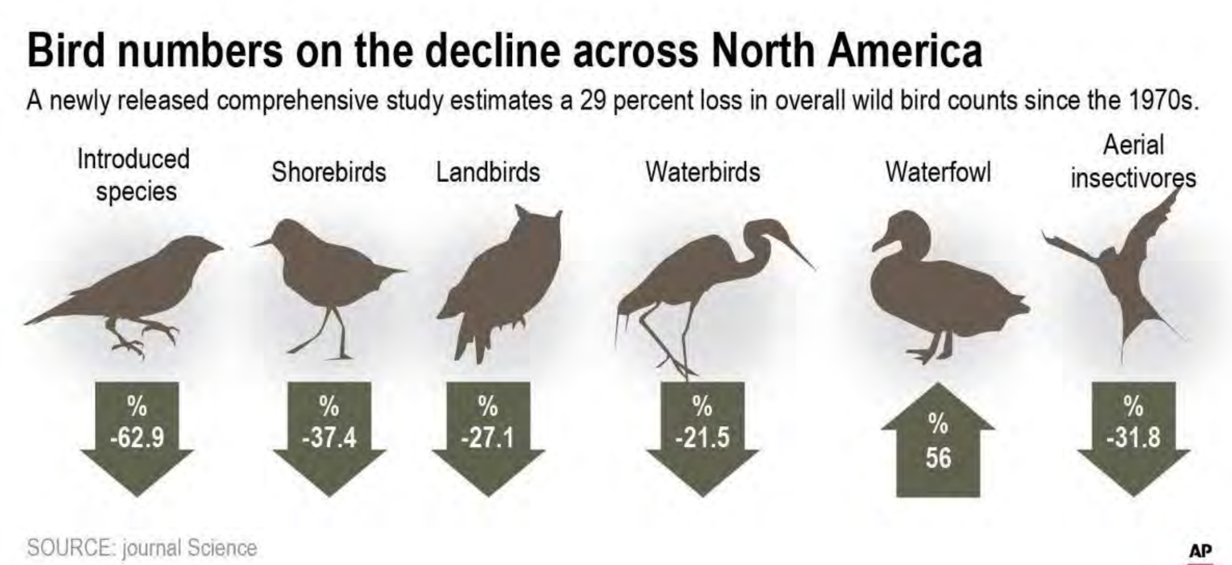
The new study focuses on the drop in sheer numbers of birds, not extinctions. The bird population in the United States and Canada was probably around 10.1 billion nearly half a century ago and has fallen 29% to about 7.2 billion birds, according to a study in Thursday's journal Science .

"People need to pay attention to the birds around them because they are slowly disappearing," said study lead author Kenneth Rosenberg, a Cornell University conservation scientist. "One of the scary things about the results is that it is happening right under our eyes. We might not even notice it until it's too late."

Rosenberg and colleagues projected population data using weather radar, 13 different bird surveys going back to 1970 and computer modeling to come up with trends for 529 species of North American birds. That's not all species, but more than three-quarters of them and most of the missed species are quite rare, Rosenberg said.

Using weather radar data, which captures flocks of migrating birds, is a new method, he said.

"This is a landmark paper. It's put numbers to everyone's fears about what's going on," said Joel Cracraft, curator-in-charge for ornithology of the American Museum of Natural History, who wasn't part of the study.



A new study finds there are nearly 3 billion fewer wild birds flying in North American skies than in 1970.;
f.duckett

"It's even more stark than what many of us might have guessed," Cracraft said.

Every year University of Connecticut's Margaret Rubega, the state ornithologist, gets calls from people noticing fewer birds. And this study, which she wasn't part of, highlights an important problem, she said.

"If you came out of your house one morning and noticed that a third of all the houses in your neighborhood were empty, you'd rightly conclude that something threatening was going on," Rubega said in an email. "3 billion of our neighbors, the ones who eat the bugs that destroy our food plants and carry diseases like equine encephalitis, are gone. I think we all ought to think that's threatening."

Some of the most common and recognizable birds are taking the biggest hits, even though they are not near disappearing yet, Rosenberg said.

The common house sparrow was at the top of the list for losses, as were many other sparrows. The population of eastern meadowlarks has shriveled by more than three-quarters with the western meadowlark nearly as hard hit. Bobwhite quail numbers are down 80%, Rosenberg said.

Grassland birds in general are less than half what they used to be, he said.

Not all bird populations are shrinking. For example, bluebirds are increasing, mostly because people have worked hard to get their numbers up.

Rosenberg, a birdwatcher since he was 3, has seen this firsthand over more than 60 years. When he was younger there would be "invasions" of evening grosbeaks that his father would take him to see in Upstate New York with 200 to 300 birds around one feeder. Now, he said, people get excited when they see 10 grosbeaks.

The research only covered wild birds, not domesticated ones such as chickens.

Rosenberg's study didn't go into what's making wild birds dwindle away, but he pointed to past studies that blame habitat loss, cats and windows.

"Every field you lose, you lose the birds from that field," he said. "We know that so many things are killing birds in large numbers, like cats and windows."

Experts say habitat loss was the No. 1 reason for bird loss. A 2015 study said cats kill 2.6 billion birds each year in the United States and Canada, while window collisions kill another 624 million and cars another 214 million.

That's why people can do their part by keeping cats indoors, treating their home windows to reduce the likelihood that birds will crash into them, stopping pesticide and insecticide use at home and buying coffee grown on farms with forest-like habitat, said Sara Hallager, bird curator at the Smithsonian Institution.

"We can reverse that trend," Hallager said. "We can turn the tide."

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Follow Seth Borenstein on Twitter at @borenbears and Christina Larson at @larsonchristina .

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The Associated Press Health and Science Department receives support from the Howard Hughes Medical Institute's Department of Science Education. The AP is solely responsible for all content.

Exhibit 70

Smithsonian.com

SmartNews Keeping you current

Even Without Ears, Oysters Can Hear Our Noise Pollution

Study shows that certain frequencies of noise cause oysters to clam up

(Wikimedia Commons)

By Jason Daley
smithsonian.com
October 27, 2017

Of course, oysters don't have ears. They've never heard the cowbell in Blue Oyster Cult's "Don't Fear the Reaper" or heard a recitation of the oyster classic, *The Walrus and the Carpenter.* But as Teresa L. Carey at PBS Newshour reports, a new study suggests that oysters may still suffer one of the downsides of having ears: noise pollution.

As Carey reports, researchers have long known that noise pollution can impact a range of sea creatures—and might even be responsible for some mass strandings of whales. Researcher Jean-Charles Massabuau of the University of Bordeaux and his team wanted to see if the sound created by boats, ships and other human activities on the water also impacted invertebrates.

Massabuau brought 32 Pacific oysters into his laboratory and used a loudspeaker to play various frequencies to the bivalves. Happy oysters tend to keep their shells cracked open; when they are stressed or face a threat, they slam their shells shut. So the team played a range of frequencies, measuring the how quickly the oysters closed their shells.

It turned out, the oysters reacted most strongly to noises between 10 and 1000 hertz, showing the most sensitivity to sounds between 10 and 200 hertz. As Douglas Quenqua at *The New York Times* reports, those lower frequencies are often produced by cargo ships, seismic research, wind turbines and pile driving. Higher frequencies created by jet skis and small boats, however, did not seem to bother the animals. They published their results in the journal *PLOS ONE*.

“They are aware of the cargo ships,” Massabuau tells Carey. “What is for sure is that they can hear. The animals can hear these frequencies.”

Of course oysters don’t hear like humans. Instead, they have hair cells on the outside of their shells that sense vibration. The researchers believe the oysters use these hairs to detect things like breaking waves and ocean currents caused by rising tides giving them cues for when to feed.

“To hear the current arriving could prepare them for eating and digesting, possibly as when we hear and smell that somebody is preparing dinner,” Massabuau tells Quenqua. Noise pollution, however, could muddle the oysters' ability to read the tides, affecting their long term health.

University of Hull marine biologist Mike Elliott, however, says it’s not clear if the noise pollution is having an impact. He has conducted similar studies on mussels and hermit crabs, who have similar reactions to certain frequencies. “It is quite a big leap from detecting a response [to sound] to if the animal is being harmed by it,” Elliott tells Carey. “The big challenge is converting this into a response that denotes harm to the organism.”

Massabuau agrees with this conclusion and plans to continue the study, focusing on whether the long-term exposure negatively impacts the oysters.

It's not just shellfish feeling the vibes. A 2015 study on general noise pollution in the oceans suggests it could be having significant impacts on a variety of species. In particular there’s growing evidence that air guns, which are used for seismic surveys, can cause hearing damage in whales and fish and stress from chronic noise pollution can negatively impact reproduction in many other species.

Perhaps, to help the creatures of the sea we first need to learn a lesson from the oysters, and just pipe down.

About Jason Daley

Jason Daley is a Madison, Wisconsin-based writer specializing in natural history, science, travel, and the environment. His work has appeared in *Discover*, *Popular Science*, *Outside*, *Men’s Journal*, and other magazines.

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Exhibit 71

https://www.sciencedaily.com/releases/2019/03/190313143307.htm

Review of noise impacts on marine mammals yields new policy recommendations

Date: March 13, 2019

Source: University of California - Santa Cruz

Summary: Marine mammals are particularly sensitive to noise pollution because they rely on sound for so many essential functions, including communication, navigation, finding food, and avoiding predators. An expert panel has now published a comprehensive assessment of the available science on how noise exposure affects hearing in marine mammals, providing scientific recommendations for noise exposure criteria that could have far-reaching regulatory implications.

FULL STORY

A trained spotted seal (Phoca largha) cooperates in an underwater hearing test at Long Marine Laboratory, UC Santa Cruz. (NMFS permit 18902)
Credit: B. Wakefield

Marine mammals are particularly sensitive to noise pollution because they rely on sound for so many essential functions, including communication, navigation, finding food, and avoiding predators. An expert panel has now published a comprehensive assessment of the available science on how noise exposure affects hearing in marine mammals, providing scientific recommendations for noise exposure criteria that could have far-reaching regulatory implications.

Published March 12 in *Aquatic Mammals*, the paper is a major revision of the first such assessment, published in 2007 in the same journal. Both efforts were led by Brandon Southall, a research associate at the Institute of Marine Sciences at UC Santa Cruz and senior scientist at Southall Environmental Associates.

"One of the things we did in 2007 was to identify major gaps in our knowledge, and we now have considerably more data. We thought there was enough new science to reconvene the panel and revisit these issues," said Southall, who served as director of NOAA's Ocean Acoustics Program from 2004 to 2009.

Concern about the potential for ocean noise to cause hearing damage or behavioral changes in marine mammals began to mount in the 1990s, focusing initially on activities related to the oil and gas industry. In the early 2000s, the association of sonar with mass strandings of deep-diving whales became another focus of concern. Shipping and construction activities are other important sources of ocean noise pollution.

Loud noises can cause temporary or permanent hearing loss, can mask other sounds, and can disturb animals in various ways. The new paper focuses on direct effects of noise pollution on hearing in marine mammals. Separate papers addressing behavioral effects and the acoustics of different sound sources will be published later this year.

"Noise-induced hearing loss occurs in animals the same way it does in humans. You can have a short-term change in response to exposure to loud noise, and you can also have long-term changes, usually as a result of repeated insults," said coauthor Colleen Reichmuth, a research scientist who leads the Pinniped Cognition and Sensory Systems Laboratory at UC Santa Cruz.

Because animals vary in their sensitivities to different types and frequencies of sound, the panel categorized marine mammal species into groups based on what was known about their hearing. The new paper includes all living species of marine mammals.

"The diversity of species is such that a one-size-fits-all approach isn't going to work," said coauthor Darlene Ketten, a neuro-anatomist with joint appointments at Woods Hole Oceanographic Institute and Boston University's Hearing Research Center. "We need to understand how to avoid harm, and the aim is to provide guidelines to say, if this or that species is in your area, here's what you need to avoid."

Over the past decade, the number of scientific studies on hearing in marine mammals has grown rapidly, enabling the panel to refine and improve its groupings and assessments. Accompanying the paper is a set of appendices compiling all the relevant information for 129 species of marine mammals.

"We did a comprehensive review, species by species, for all living marine mammals," said Reichmuth, who led the work on the appendices. "We pulled together the available knowledge covering all aspects of hearing, sound sensitivity, anatomy, and sound production. That's the scientific basis for the species groupings used in the noise exposure criteria."

"The appendices are a really important resource that does not exist anywhere else," Southall said. "The 2007 paper was the most impactful single paper I've ever published -- it's been cited in the literature more times than all my other papers combined -- and I expect this new paper will have a similar impact."

The 2007 paper covered only those species under the jurisdiction of the National Marine Fisheries Service (NOAA Fisheries). NOAA Fisheries issued U.S. regulatory guidance in 2016 and 2018 based on the 2007 paper and a 2016 Navy technical report by James Finneran, a researcher at the U.S. Navy Marine Mammal Program in San Diego and a coauthor of both papers.

In addition to covering all marine mammals for the first time, the new paper also addresses the effects of both airborne and underwater noise on amphibious species in coastal environments, such as sea lions. According to Southall, publishing the new noise exposure criteria along with a comprehensive synthesis of current knowledge in a peer-reviewed journal is a major step forward.

"There are regulatory agencies around the world that are thirsting for this kind of guidance," Southall said. "There are still holes where we need more data, but we've made some big strides."

Research on seals, sea lions, and sea otters at the UCSC Pinniped Lab now run by Reichmuth has provided much of the new data on hearing in amphibious marine mammals. Working with trained animals at UCSC's Long Marine Laboratory, Reichmuth's team is able to conduct controlled experiments and perform hearing tests similar to those used to study human hearing.

Finneran's program in San Diego and coauthor Paul Nachtigall's program at the University of Hawaii have provided much of the data for dolphins and other cetaceans.

But some marine mammals, such as baleen whales and other large whales, simply can't be held in a controlled environment where researchers could conduct hearing tests. That's where Ketten's research comes in. Ketten uses biomedical imaging techniques, including CT and MRI, to study the auditory systems of a wide range of species.

"Modeling an animal's hearing based on the anatomy of its auditory system is a very well-established technique that can be applied to baleen whales," Ketten explained. "We also do this modeling for the species that we can test in captivity, and that enables us to hone the models and make sure they're accurate. There has been a lot of resistance to modeling, but it's the only way to study hearing in some of the species with the greatest potential for harm from human sounds."

Southall said he regularly hears from people around the world looking for guidance on regulating noise production by activities ranging from wind farm construction to seismic surveys. "This paper has significant international implications for regulation of noise in the ocean," he said.

Story Source:

Materials provided by **University of California - Santa Cruz**. Original written by Tim Stephens. *Note: Content may be edited for style and length.*

Journal Reference:

1. Brandon L. Southall, James J. Finneran, Colleen Reichmuth, Paul E. Nachtigall, Darlene R. Ketten, Ann E. Bowles, William T. Ellison, Douglas P. Nowacek, Peter L. Tyack. **Marine Mammal Noise Exposure Criteria: Updated Scientific Recommendations for Residual Hearing Effects**. *Aquatic Mammals*, 2019; 45 (2): 125 DOI: 10.1578/AM.45.2.2019.125

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The World – Coos Bay
https://theworldlink.com/news/local/utvs-to-takeover-box-car-hill-this-weekend/article_c3258d6e-e77f-5073-b28c-8d2a657c7186.html

UTVs to 'takeover' Box Car Hill this weekend

NICHOLAS A. JOHNSON - The World
Jun 27, 2019

Riders navigate at the dunes Wednesday at Box Car Hill during the UTV Takeover in North Bend.
Ed Glazar The World

A message scrawled on a sand covered tire Wednesday during the UTV takeover at Boxcar Hill Campground in North Bend. Ed Glazar The World

NORTH BEND — Once again the UTV Takeover has, as its name suggests, taken over Box Car Hill with thousands coming from all over to watch and participate in a weekend full of ATV and UTV events.

While most leave the events to the professionals and just come for a viewing, nearly anyone can participate in the various events from June 26-30 out on Box Car Hill, located on the Transpacific Highway north of the McCullough Bridge. Events run all day and entry to the takeover costs $25 for general admission.

UTV Takeover
A rider speeds up a hill Wednesday out of Box Car Hill campground during the UTV Takeover in North Bend.

A Utility Task Vehicle, also known as a side-by-side, is similar to an all-terrain vehicle but typically larger and uses a steering wheel and pedals rather than handlebars and can carry passengers.

Events include more extreme activities like barrel racing, drag strip racing, and a wheeliefest. However, there are plenty of events throughout the weekend for those who might prefer to just eat food, listen to music and watch the more adventurous types tear around the dunes.

The Sand Outlaw is a helmets-required event where two drivers face off and simultaneously barrel down two equal tracks, the distance of two football fields. The course contains several elevation changes, jumps, crossovers and hurdles. The competition is single elimination, with winners moving on to another round and losers staying back to watch. Like most larger events, the prize for the Sand Outlaws event is $100 and four raffle tickets, with second being $50 and two raffle tickets.

UTV Takeover
An vehicle sits Wednesday among vendor tents during the UTV takeover at Boxcar Hill Campground in North Bend.

Some of the less competitive events only net winners $40 and four raffle tickets or $20 and two raffle tickets. Events like the Blind Bandit adhere to this prize structure. The Blind Bandit event sees blindfolded drivers attempt to navigate through a tight obstacle course, while receiving only verbal instructions from the passenger.

Throughout the takeover, participants and spectators have the opportunity win and purchase raffle tickets. Those entered in the raffle have a chance to win up to $20,000 in prizes from various sponsors and vendors.

Nicholas A. Johnson can be reached at 541-266-6049, or by email at nicholas.johnson@theworldlink.com.

Exhibit 74

From: Dan Shoemaker (FAA)
Sent: Wednesday, January 20, 2016 10:08 AM
To: Jody McCaffree; Robert VanHaastert (FAA)
Cc: Mitch T Swecker (OR Dept Aviation); Jeff CAINES (OR Dept Aviation); Heather Peck (OR Dept Aviation)
Subject: RE: RE - Jordan Cove LNG Export Project airport concerns

Good morning, Ms. McCaffree.

I appreciate your taking the time to express your concerns regarding the potential for plume and flare effects on aircraft operations at Southwest Oregon Regional Airport. However, the FAA obstruction evaluation process is limited to only the physical effect the structure would have on Part 77 airspace surfaces; instrument procedures and routes; air traffic control minimum flight and vectoring altitudes; runway design surfaces; radar, communications, and radio navigational and landing aid signals; and visual landing aids and control tower visibility arcs. While the FAA can make advisory statements about other potential issues, such as exhaust plumes and flares, visual and thermal glare, and thermal and mechanical turbulence, it cannot determine a structure to be a hazard to air navigation based solely upon these factors. These are ultimately land-use issues that must be decided by local governments, based upon the FAA's guidance. The memoranda you cited are just that: advisory in nature, and intended to give land-use decision makers information with which they can rule on proposed structures and facilities.

As a result, the FAA Obstruction Evaluation Group cannot reconsider the previously issued determinations of no hazard to air navigation.

Dan Shoemaker
Airspace Specialist
Seattle Obstruction Evaluation Group
[redacted]

From: Jody McCaffree
Sent: Tuesday, January 19, 2016 4:15 PM
To: 'Dan Shoemaker (FAA)'; 'Robert VanHaastert (FAA)'
Cc: Mitch T Swecker (OR Dept Aviation); Jeff CAINES (OR Dept Aviation); Heather Peck (OR Dept Aviation)
Subject: RE - Jordan Cove LNG Export Project airport concerns

Dear Mr. Shoemaker and Mr. VanHaastert:

On January 7, 2016, the Jordan Cove Energy Project (JCEP) filed FAA form 7460-2 for extensions of the following determinations by the FAA. (See listing below)

I would like to request that the FAA reconsider some of their determinations of "NO HAZARD TO AIR NAVIGATION" in some of these filings.

On January 21, 2015, and September 24, 2015, the FAA released memorandums concerning: "*Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations.*" In these memorandums the FAA determined that *thermal exhaust plumes in the vicinity of airports may pose a unique* *hazard to aircraft in critical phases of flight (particularly takeoff, landing and within the pattern) and therefore are incompatible with airport operations*.

The proposed Jordan Cove LNG Export project would be releasing considerable amounts of heat into the atmosphere from their two (2) proposed gas flares, their six (6) proposed South Dunes Power Plant (SDPP) venting stacks and their six (6) proposed LNG liquefaction trains. No one to my knowledge has addressed this issue or the cumulative impacts from Jordan Cove releasing all this high volume of heat into the atmosphere in the vicinity of the Southwest Oregon Regional Airport flight paths. Jordan Cove's July 2013 Thermal Plume Study considered only 5 SDPP venting stacks and did not consider Jordan Cove's proposed gas flares, liquefaction trains or the operation of the facility at full build out.

No single proposed component of the Jordan Cove LNG Export project would be able to exist without the other components, so it is essential that the cumulative impacts of Jordan Cove's proposed structures be considered with respect to potential impacts to the Southwest Oregon Regional Airport.

Jordan Cove is proposing to raise their current static property levels to 46 and 60 feet in height in the vicinity of their proposed LNG terminal facility. The cumulative impact of all their proposed structures could and most likely would cause electrical and/or multipath interference for aircraft which may lead to navigational errors in critical phases of air flight. One accident is all it would take to cause cascading failures at the proposed LNG facility and the potential for a catastrophic accident affecting the entire Coos Bay area.

Going forward, please consider carefully your decisions with respect to the following FAA filings by the proposed Jordan Cove LNG facility. I would like to be notified of any additional decisions made by the FAA on these filings and/or chances for citizen comment.

Citizens have rebuttal comments due on January 26, 2016, under Coos County Land Use file No. HBCU-15-05 for the proposed Jordan Cove LNG facility. Any help I can obtain with determining Jordan Cove's entire *thermal plume hazard* would be appreciated.

The following Jordan Cove proposed structures are currently up for FAA form 7460-2 review and extensions:

Flare at JCEP South Dunes Power Plant Exp 1-24-2016
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=201501157

Flare at JCEP Storage / Liquefaction Exp 1-24-2016
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344098

Amine Contractor 2-E
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344077

Amine Contractor 1-W
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344066

TURG/HRSG Stack 6
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194342174

TURG/HRSG Stack 5
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194340340

TURB/HRSG Stack 4
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194340310

TURB/HRSG Stack 3
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194340287

TURB/HRSG Stack 2
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194340280

TURB/HRSG Stack 1
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194340290

Transmission Line: 13R-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338098

Transmission Line: 13L-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338096

Transmission Line: 12-Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338092

Transmission Line: 11R-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338087

Transmission Line: 11L-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338083

Transmission Line: 10-R-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338048

Transmission Line: 10-L-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338047

Transmission Line: 9-R-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338044

Transmission Line: 9-L-Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338003

Transmission Line: 8 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338001

Transmission Line: 7 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338000

Transmission Line: 6 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337998

Transmission Line: 5 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337989

Transmission Line: 4 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337978

Transmission Line: 3 - Suspension
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337969

Transmission Line: 2-R – Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337956

Transmission Line: 2-L – Dead-end
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337948

Building: Compressor Shelter Roof 1-N
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344104

Building: Compressor Shelter Roof - 2
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344125

Building: Compressor Shelter Roof - 3
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344128

Building: Compressor Shelter Roof - 4-S
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194344131

The following Jordan Cove structures are not currently up for FAA form 7460-2 review and extension but are essential components of the LNG facility:

LNG Storage Tanks – Two (2) - FAA Notice of Presumed Hazard 7-24-2014
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194337946

LNG Storage Tank – North - FAA Notice of Presumed Hazard 7-24-2014
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=195630983

Amine Tower 2-E - FAA Notice of Presumed Hazard 7-24-2014
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338105

Amine Tower 1-W – FAA Notice of Presumed Hazard 7-24-2014
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=194338102

LNG Carrier Vessel - Docked – Completed 6-25-2015 with expiration 12-25-2016
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=195631327

LNG Carrier Vessel – Transiting through Bay – Not completed - Work in Process
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=253732721
and
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=249632862

Monopole - Not completed - Work in Process
https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=displayOECase&oeCaseID=273550454

Sincerely,

Jody McCaffree
PO Box 1113
North Bend, OR 97459
[redacted]

Exhibit 75

LEGEND

- Manhole
- Pump Station
- Settling Pond
- Landfill

Leachate Lines

- Existing Leachate Line
- New Leachate Line
- Disconnect Leachate Line

City Water Lines

- Existing City Water Line
- New Water Line
- Disconnect City Water Line

BASIN DETAIL PLAN FROM FILE BY GSI WATER SOLUTIONS, INC., DATED FEBRUARY 28, 2012

North

0 180 360 FT

GRI JORDAN COVE ENERGY PROJECT
FORMER WEYERHAEUSER MILL SITE AND INGRAM YARD
WORK PLAN FOR JOINT PROGRAM REGULATORY CLOSURE

BASIN DETAIL PLAN

JULY 2013 | JOB NO. 4277-S | FIG. 3

RESIDUAL MILL CONTAMINATION FROM FILE BY DEQ (2012)

North

0 400 800 FT

GRI JORDAN COVE ENERGY PROJECT
FORMER WEYERHAEUSER MILL SITE AND INGRAM YARD
WORK PLAN FOR JOINT PROGRAM REGULATORY CLOSURE

RESIDUAL MILL CONTAMINATION

JULY 2013 JOB NO. 4277-S FIG. 4

Exhibit 76

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
September 7, 2019

Re:
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000
Response to August 28, 2019 PHMSA Data Request

My comments are not to be attributed to the University of Arkansas.

This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016; September 22, 2018; October 2, 2018; December 3, 2018; April 1, 2019; July 18, 2019; and August 27, 2019 - all of which I stand by.

On August 28, 2019, the U.S. Department of Transportation, Pipeline and Hazardous materials Safety Administration (PHMSA) Staff issued questions and information requests related to PHMSA's review of the siting requirements under 49 CFR Part 193,Part B ("August 28 PHMSA Request").

These comments address only JCEP's response to Scenarios MR-2 involving the use of FLACS-Fire. However, these comments are not directed to the details of the calculations (using FLACS-Fire) presented for Scenario MR-2. My purpose here is to emphasize the same concerns raised in my previous (August 27, 2019) comments, and to expand on the importance of PHMSA taking immediate corrective action.

I believe that the use of FLACS-Fire in JCEP's submission effectively circumvents the intent of 49 CFR Part 193, Part B because it has not been approved by PHMSA for such use. If I am wrong about this, I respectfully ask that PHMSA immediately notify me, and I will take the necessary corrective action.

If I am not wrong about this, I believe we are, as a result of this action, further enabling the applicant to circumvent the Regulations in a manner that will result in important decreases in the provision of Public Safety.

The current LNG regulations focus on providing public safety by requiring that the applicant provide approved science-based calculations of exclusion distances to prevent public injury beyond the plant boundaries from liquid pool fires and vapor cloud fires and explosions.

The FLACS model, which is increasingly used in applications for LNG Export Terminal Siting applications, is a complex suite of mathematical modeling methods that are advertised to address the calculation of Dispersion, Fire Radiation, and Vapor Cloud Explosion hazards.

The FLACS Model used by JCEP designed to predict dispersion has received PHMSA approval for use in applications to meet the requirements of 49 CFR 193.

The FLACS Model used by JCEP designed to predict vapor cloud explosion overpressures has not received such approval.

It is my understanding that the FLACS-Fire Model used by JCEP in the application here considered to calculate fire radiation intensity to ensure that the prescribed radiation limits do not extend beyond the property values has not received such approval.

If I am correct in the assumptions I have made here, I believe there has been a critically important failure to provide for Public Safety in the current regulations designed for siting LNG Export Terminals. The current regulations were designed for LNG Import Terminals. It is established knowledge that Export Terminals involve important hazards that are not present in Import Terminals. There has been a failure to update the Regulations accordingly. I am very concerned that the current moves to provide “Regulatory Relief While Preserving Public Safety” are going badly wrong. In my opinion, just as in the current debate about the science information about Global Warming/Climate Change, the debate about the push to expand the LNG Export business in the United States is allowing the Export Terminal applicants-for-siting to cut regulatory corners by adopting complex mathematical models that are used to determine the risks involved without proper science-based evaluation.

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
August 27, 2019

Re:
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000
Part 193, Subpart B Siting Review Supplement

My comments are not to be attributed to the University of Arkansas.

This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, December 3, 2018, April 1, 2019 and July 18, 2019 - all of which I stand by.

On August 14, 2019, the U.S. Department of Transportation, Pipeline and Hazardous materials Safety Administration (PHMSA) Staff issued questions and information requests related to PHMSA's review of the siting requirements under 49 CFR Part 193,Part B. These comments address only the first Information Request (Request 1):

> *In response to Request 2 from the PHMSA Information Request dated August 2, 2019, the analysis considered the 2-dimensional Phast output results from a jet fire occurring from release scenario LNG-17 that indicated at a flame height of 96.23 feet, the impacts from a jet fire do not extend over the 100-foot wall. Furthermore, the Phast output summary file provided for scenario LNG-17 indicates the length of the flame is 584 feet, which appears to be greater than the distance between the release location and the 100-foot wall. This means the tip of the flame as well as its thermal radiation may spread vertically along the height of the wall. Since the 2-dimensional analysis does not account for this spreading of the flame, the height not extending over the 100 foot wall is not indicative of the exclusion zone remaining onsite.*
>
> *In addition, it remains unclear whether the radiant heat from a jet fire from MR-2 will remain onsite.*
>
> *Provide an analysis that demonstrates the 1600 Btu/hr-ft^2 from jet fire scenarios LNG-17 and MR-2 would remain within the property legally controlled by Jordan Cove using a modeling software that accounts for the obstruction from plant equipment and the 100-foot wall.* *(emphasis added)*

JCEP provided two figures with accompanying text from which they appear to conclude that the 1600 Btu/hr-ft^2 (thermal radiation level?) from jet fire scenarios LNG-17 and MR-2 would remain within the property legally controlled by Jordan Cove. JCEP's response stated that these two scenarios were modelled using FLACS-Fire version 10.9.

It is my understanding that the currently applicable version of CFR193.2057, Thermal radiation protection, requires that thermal radiation distances must be calculated using Gas Technology Institute's (GTI) report or computer model GTI-04/0032 LNGFIRE3: A Thermal Radiation Model for LNG Fires (incorporated by reference, see 193.2013). The use of other alternate models which take into account the same physical physical factors and have been validated by experimental test data may be permitted subject to the Administrator's approval.

I am here respectfully requesting an answer to the following questions:

1. Has a request from, or on behalf of, JCEP been received by PHMSA for approval of the alternate (to LNGFIRE3) FLACS-Fire Version 10.9 model?
2. If such a request has been received, please provide a statement of PHMSA's response to the request.

From my position of working specifically on these matters of the calculations submitted by JCEP to obtain approval for the siting of the LNG export terminal in Coos Bay, Oregon since early 2015, and my four decades experience with PHMSA and other governmental regulators in trying to ensure that the regulations in force utilize good, carefully vetted, scientific tools to protect public safety, I am saddened to feel that the safety regulation process is being circumvented.

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
July 18, 2019

Regarding the
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT
Docket Nos. CP17-494-000 and CP17-495-000
of March 2019

My comments are not to be attributed to the University of Arkansas.

COMPUTER MODEL USED TO PREDICT LNG EXPORT TERMINAL VAPOR CLOUD EXPLOSION HAZARDS HAS NOT BEEN APPROVED BY PHMSA – THERE IS NEW PUBLISHED INFORMATION CONCERNING THE UNCERTAINTY IN THE FLACS EXPLOSION CALCULATIONS

This comment is intended to notify PHMSA of new developments regarding our knowledge of the risk of cascading fire and unconfined vapor cloud explosion (UVCE) accidents that could occur at the Jordan Cove Export Terminal (JCET). This comment expands on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, December 3, 2018, and April 1, 2019 - all of which I stand by.

As stated in my previous comments, my review of the March 2019 JCET DEIS did not disclose any detailed predictions of vapor cloud explosion (VCE) overpressure for design spills of heavy hydrocarbons, but I did locate on the FERC Website a report entitled “Facility Siting Hazard Analysis”, dated October 2, 2018, which presents a collection of hazard footprints for overpressure, calculated with FLACS, predicted to result from design spills of heavier-than-methane hydrocarbons at the JCET[1]. The overpressures presented therein still appear to be significantly lower than those reported for numerous incidents that have occurred with the same materials, in similar amounts and in similar conditions. I am very concerned that such predictions might be approved by FERC in the FEIS - repeating the approval of similar predictions prepared for FERC with the same mathematical model FLACS in 2015.

Although a process for developing a written protocol for evaluation of FLACS for application to the prediction of overpressures was requested by PHMSA to be funded following the LNG Regulation Workshop of 2016[2], it appears that the plans announced at the LNG Workshop of 2016 for a required updating of 49 CFR 193 to cater for the new hazards that will be present at export terminals are at a standstill.

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[1] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198
Click on “Facility Siting Hazard Analysis” and download

[2] https://primis.phmsa.dot.gov/rd/mtgs/111616/WG%205%20Report-Out.pdf – See GAP #4

Sub-Model Q9

It is my understanding that the sub-model named Q9 was used in FLACS to compute the explosion overpressure predictions in the Jordan Cove DEIS. I believe those predictions may well be an order-of- magnitude too low. As the FLACS model has yet to be evaluated by subjection to a written Protocol, as currently required by PHMSA, it follows that the sub-model Q9 has not been evaluated either.

The purpose of this comment is to request that PHMSA consider a scientific review paper regarding Q9 recently published by the British Health and Safety Executive[3]. I believe this paper substantiates my concerns that there are such large uncertainties in the Q9 method, as utilized currently in FLACS, as to result in order of magnitude (too low) errors in overpressures. Such errors could result in the dismissal of the UVCE hazard for heavy hydrocarbon gas clouds considered as “Design Spills” in the recent Jordan Cove DEIS. I am very concerned that correction of these errors has the potential to change the overpressures presented in the Jordan Cove DEIS to indicate overpressures an order of magnitude higher, which would bring those predictions into substantial agreement with the extensive historical review by the British Health and Safety Laboratories presented at the LNG Regulatory Workshop in 2016. Such overpressures could well lead to destruction of the plant and extend danger to the public outside the controlled boundary.

[3] Stewart, J., Gant, S. and Bilio M. (2019) “A review of the Q9 Equivalent cloud method for explosion modelling”, Fire and Blast Information Group (FABIG) Technical Newsletter 75, March 2019. Available from: http://www.fabig.com/video-publications/TechnicalNewsletters

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
April 1, 2019

Regarding the
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT
Docket Nos. CP17-494-000 and CP17-495-000
March 2019

My comments, directed simultaneously to FERC and PHMSA,
are not to be attributed to the University of Arkansas.

COMPUTER MODEL USED TO PREDICT LNG EXPORT TERMINAL VAPOR CLOUD EXPLOSION HAZARDS HAS NOT BEEN APPROVED BY PHMSA - PREDICTED EXPLOSION OVERPRESSURES APPEAR SERIOUSLY UNDERESTIMATED

These comments are intended to notify FERC, PHMSA, and the public of critically important developments regarding our expanding knowledge of the risk of cascading fire and unconfined vapor cloud explosion (UVCE) accidents that could occur at the Jordan Cove Export Terminal (JCET). The comments are an expansion on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, and December 3, 2018 - all of which I stand by. They are also intended as a response to the joint news release of August 31, 2018 by PHMSA and FERC, entitled " FERC, PHMSA Sign MOU to Coordinate LNG Reviews**"**, from which I quote - "The MOU establishes a framework **for** coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public impacts". I trust these comments will be helpful to the decision-makers in fully informing the public.

My concerns remain essentially the same as commented to FERC in January 2015 by James Venart and myself[1]. I believe that Government is failing to adequately provide for the risks of potentially devastating Unconfined Vapor Cloud Explosions (UVCEs) of heavier-than-methane hydrocarbons at the JCET.

I remain concerned that the predictions of explosion overpressures (determining explosion damage) presented in the 2015 JCET DEIS were an order of magnitude (factor 10) too low. Such overpressures are not conservative enough to indicate the real hazard that exists, as evidenced by numerous confirmed occurrences of devastating UVCEs involving the same heavy hydrocarbons in similar conditions.

My review of the March 2019 JCET DEIS did not disclose any detailed predictions of vapor cloud explosion (VCE) overpressure for design spills of heavy hydrocarbons. However, I did locate on the FERC Website a report entitled "Facility Siting Hazard Analysis", dated October 2, 2018, which

[1] UNITED STATES LNG TERMINAL SAFE-SITING POLICY IS FAULTY, Comments submitted to FERC by Jerry Havens and James Venart, January 14, 2015, Docket No. CP13-483.

presents a collection of hazard footprints for overpressure, calculated with FLACS, predicted to result from design spills of heavier-than-methane hydrocarbons at the JCET[2]. The collection of calculations presented in that report presents a picture very similar to that presented in the 2015 DEIS. The overpressures presented therein still appear to be significantly lower than those reported for numerous incidents that have occurred with the same materials, in similar amounts and in similar conditions. I cannot determine to what extent these newer predictions have been utilized in the 2019 DEIS, but I am very concerned that such predictions as these might be approved by FERC in the FEIS - repeating the approval of similar predictions prepared for FERC with the same mathematical model (FLACS) in 2015. If that were to happen, I believe a serious error affecting public safety will be the result, because the unrealistically low damage predictions could be used again by FERC as a basis to dismiss the UVCE hazard at the JCET. Continued dismissal of the UVCE hazard would be a very serious error. <u>If the magnitude of the possible overpressures are estimated using actual data (experience) available for UVCEs (rather than predicted with the FLACS theoretical model), the VCE hazard would be clearly indicated as a serious major hazard at the JCET[3].</u> <u>*UVCEs at numerous similar heavy hydrocarbon handling/storage facilities have resulted in destruction of the facilities as well as injuries and deaths beyond the plant boundaries.*</u>

Contrasting LNG Import and Export Terminal Siting Regulations

I want to state here that if either PHMSA or FERC believes that anything I present is in error I request that I be notified immediately. I will make any corrections as necessary, and I will alter my comments, as necessary, as well. My goal is to ensure that the science-based tools that are used for hazard evaluation in the regulations are applied correctly. I am very concerned that failure to ensure proper, validated, use of mathematical models for UVCE hazard evaluation could result in devastating UVCEs that, in addition to public endangerment, could cripple the industry.

In order to most effectively explain my concerns, I think it helpful to provide a very brief history of the LNG regulations. The provisions of 49 CFR 193. Liquefied Natural Gas Facilities: Federal Safety Standards were developed by PHMSA to govern the siting of LNG peak shaving terminals and <u>import</u> terminals. It has been accepted practice to identify for these two types of terminals <u>only</u> two principal hazards; pool fire hazards and vapor dispersion hazards. A third hazard, Unconfined Vapor Cloud Explosion (UVCE), is generally considered negligible for Import Terminals. This policy is based on the generally accepted fact that import terminals handle and store primarily LNG with methane contents sufficiently high that the LNG can be assumed to be pure methane. Given the very low propensity for explosion of unconfined methane-air clouds, UVCEs at LNG import terminals have historically been neglected as a hazard. <u>As a consequence the present Regulation, 49 CFR 193, does not mandate the consideration of UVCE hazards</u>.

With the advent of LNG export terminals in the United States the requirements for safe siting of LNG terminals have changed importantly. That is because the export terminals typically remove and store large quantities of heavier-than-methane hydrocarbons from the incoming natural gas feed stream. Furthermore, the removal of those heavy hydrocarbons typically requires the use of

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[2] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198
Click on "Facility Siting Hazard Analysis" and download

[3] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111 Atkinson, G., Vapor Cloud Explosion (VCE) Historical Review, PHMSA Public Workshop on Liquefied Natural Gas (LNG) Regulations, Washington DC, 19 May 2016.

large quantities of refrigerant gases that are heavier-than-methane hydrocarbons. The storage and handling of large quantities of these heavier-than- air hydrocarbons results in a new primary hazard - vapor cloud explosions of the heavy hydrocarbon materials that could follow accidental release.

I have been involved in the development of 49 CFR 193 from its beginning in the early 1980s. My principal involvement has been as an author/evaluator of the DEGADIS model for use in predicting LNG vapor cloud dispersion. DEGADIS is approved by PHMSA for use in predicting the requirements for vapor cloud dispersion exclusion zones for LNG Import Terminals. During the last decade, and coincident with the advent of LNG Export Terminals in the United States, additional vapor dispersion models have been approved by PHMSA for use by LNG terminal companies seeking siting approval.

My comments here are restricted to the FLACS model. The FLACS model is an example of what is known as a computational fluid dynamics (CFD) model. I generally support the use of CFD models for vapor dispersion predictions because they are appropriate for dealing with complexities not catered for by simpler models such as DEGADIS. Accordingly, I supported the approval by PHMSA of the FEM3A model developed by the Lawrence Livermore National Laboratory (LLNL) and I supported the request for PHMSA approval of FLACS for vapor dispersion use. I do not object to FLACS' approval, which PHMSA granted, for vapor dispersion prediction.

FLACS has not been Evaluated or Approved by PHMSA for Explosion Prediction

This is the crux of the matter. There are now four mathematical models approved by PHMSA for vapor dispersion prediction, in order of the time approved; DEGADIS, FEM3A, FLACS, and PHAST. All four were required by PHMSA to be subjected to evaluation of their performance in demonstrating suitable agreement with experimental data available from a collection of field and wind tunnel tests of vapor dispersion.

FLACS (FLame ACceleration Simulator) is a commercial Computational Fluid Dynamics (CFD) software used extensively for atmospheric dispersion modeling and explosion modeling in the field of industrial safety and risk assessment[4]. FLACS has been subjected to the written protocol provided by PHMSA and approved by PHMSA for vapor dispersion predictions required by 49 CFR 193. PHMSA has not completed development of a written protocol for the evaluation of FLACS for explosion prediction. Consequently, FLACS has not been formally evaluated for explosion prediction and has not received approval for the evaluation of UVCE hazards (read explosion overpressures) by PHMSA.

Although it appears that a process for developing a written protocol for evaluation of FLACS for application to the prediction of overpressures was requested by PHMSA to be funded following the LNG Regulation Workshop of 2016[5], I can find no evidence that the required protocol has been completed. It appears that the plans announced at the LNG Workshop of 2016 for a required updating of 49 CFR 193 to cater for the new hazards that will be present at export terminals are currently at a standstill. The only conclusion I am able to reach is that the newly announced JCET DEIS appears to me likely to utilize predictions of explosion overpressures for the heavier-than-methane hydrocarbon design spills selected for analysis that have not been approved by PHMSA. Such a failure to adequately address the risk of UVCEs would mean that potential risks of cascading

[4] https://en.wikipedia.org/wiki/FLACS

[5] https://primis.phmsa.dot.gov/rd/mtgs/111616/WG%205%20Report-Out.pdf – See GAP #4

violent explosions that could destroy the plant as well as extend dangers to the public beyond the facility boundary are effectively being ignored.

PHMSA Contracted for Expert Evaluation of the Risk of Unconfined Vapor Cloud Explosions

Simultaneously with my comments to FERC in 2015 I notified PHMSA of my concerns. I have also filed a total of four comments (to date) on PHMSA's LNG Regulation Workshop site. Further, there have been a series of important developments subsequent to my 2015 comments to FERC, the results of which I think are critically important to consider now.

PHMSA contracted with the British Health and Safety Laboratories (HSL) to prepare the report "Review of Vapour Cloud Explosion Incidents"[6]. Quoting excerpts from the Executive Summary of that report:[7]

> **"T**his review of major vapor cloud incidents has been jointly commissioned by the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and the UK Health and Safety Executive (HSE). The primary objective was to improve understanding of vapor cloud development and explosion in order to examine the potential for these hazards to exist or develop at LNG export plants that store substantial quantities of these flammable gases for use in the liquefaction process or as a by-product from the liquefaction …
>
> This review has not found any historical records of LNG (methane) vapor cloud explosions in open areas with severity sufficient to cause secondary damage to tanks and pipes and consequently rapid escalation of an incident from a minor process leak to a major loss of inventory.
>
> On the other hand some LNG sites (especially export sites) also hold substantial amounts of refrigerant gases and blends containing ethane, propane, ethylene and iso-butane. Higher hydrocarbons may also be produced and stored on LNG export sites as by-products of gas condensation. There are numerous examples of Vapor Cloud Explosions (VCEs) in open areas involving these higher molecular weight materials and the storage and use of higher molecular weight hydrocarbons on LNG export sites which may, if not managed adequately, introduce an additional set of incident scenarios in which VCEs trigger rapid escalation of loss of containment. (emphasis added)
>
> This study involves a review of 24 major VCE incidents focusing on source terms, cloud development and explosion mechanics. The incidents studied are split between permanent fuel gas (C2-C4 (e.g. LPG) and volatile liquids C4-C6 (e.g. gasoline). The source terms for leaks of gases and liquids are different but once a stable current of cold heavy vapor forms, the subsequent development of LPG and gasoline clouds are similar…
>
> An important finding from the review is that a high proportion of vapor cloud incidents occurred in nil/low wind conditions. By the term "nil/low wind" we mean a wind that was so weak close to the ground that it only detrained (stripped away) a small proportion of the vapor accumulating around the source … Rather than being picked up and moved downwind, the vapor flow in this case was gravity driven; spreading out in all directions and or following any downward slopes around the source.
>
> In many of the cases examined, 50% (12/24), there is clear evidence from the well-documented transport of vapor in all directions and/or meteorological records that the

[6] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111

[7] HSL Report on PHMSA LNG Regulation Workshop site.

vapor cloud formed in nil/low wind conditions. In a further 21% (5/24), the pattern of vapor suggests nil/low wind conditions but there is insufficient data available to be sure … incidents in nil/low wind conditions apparently make up the majority of historical records of the most serious VCEs … In nil/low wind conditions the cloud continues to grow throughout the time that the tank takes to empty… The maximum area covered by the flammable cloud is typically several hundred times greater in nil/low winds condition than in light winds.

The implication of this type of analysis is that if the density of ignition sources is constant and quite low in the area around the tank the chances of ignition in nil/low wind conditions would be hundreds of times greater for a given release. This illustrates why nil/low wind conditions dominate records of major vapor cloud incidents even though the weather frequency is low. Losses of containment in nil/low wind conditions are also particularly dangerous because a highly homogeneous cloud can be formed that may spread by gravitational slumping (without significant dilution) for hundreds of meters… A very large cloud that is all close to the stoichiometric ratio increases the risk of flame acceleration to a high pressure regime capable of seriously damaging storage and process facilities, when compared with clouds that are entraining air because of wind-driven dilution. This is because fundamental burning rates fall off rapidly for concentrations away from the stoichiometric. Once a high pressure regime is established explosions are not confined to congested areas of a site. In many of the cases reviewed almost all the footprint of the cloud was exposed to pressures in excess of 2000 mbar (29 psi). In at least one case the cloud detonated, causing extremely severe damage over the area covered by the cloud)." (emphasis added)

PHMSA Conducted a Public Workshop on Liquefied Natural Gas (LNG) Regulations

The Workshop was conducted in Washington, DC in May 2016. Quoting excerpts from PHMSA's Statement of Mission (from the Workshop Website):

"Historically, most LNG facilities were peak shavers built to liquefy and store natural gas to be degasified and injected back into the pipeline during periods of peak demand … However, due to the recent abundance of domestic shale gas, LNG export terminals are now being constructed that liquefy vast volumes of natural gas. These facilities require significantly greater quantities of refrigerants to liquefy the natural gas than the amount typically used at peak shavers… Most refrigerant gases and blends used at the export facilities contain ethane, propane, ethylene, and iso-butane and are referred to as heavy hydrocarbons. These gases are similar to gases that have resulted in VCEs at petrochemical facilities…

The understanding of VCEs is evolving. PHMSA recognizes that significant quantities of heavy hydrocarbons present different risks than methane and seeks to better understand that risk. Prior to investigative work on the Buncefield accident, the prevailing understanding was that vapor clouds formed outdoors were unlikely to explode if ignited. Today it is understood that VCEs involving higher hydrocarbons have occurred in outside areas. This paper advances our understanding further. PHMSA sponsored the "Review of Vapour Cloud Explosion Incidents" report with the primary objective to improve the scientific understanding of vapour cloud development and explosion in order to more reliably assess hazards at large Liquid Natural Gas (LNG) export facilities… The aim of reviewing the particular incidents in this report is the extensive forensic evidence available that provides the information needed to study how the vapor cloud formed and ignited, the amount of overpressure exerted, and other information about the mechanism of VCE. This research was performed by the Health and Safety Laboratory (HSL) under a subcontract with the Oak Ridge National Laboratory, a United States Department of Energy (DOE) facility, and was supported by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA and DOE) and the United Kingdom Health and Safety Executive (HSE). The research's objective was to improve understanding of vapor development and explosions in order to more reliably assess hazards and safety measures at facilities that contain significant quantities of heavy hydrocarbons…

The technical review of the report was performed by uncompensated subject matter experts… The purpose of this independent review was to provide candid and critical comments to make the report as sound as possible… The review, comments, and draft manuscript remain confidential to protect the integrity of the deliberative process. The panel reviewed multiple drafts of the report, held several conference calls, and convened a meeting on May 17th (2016) in Washington, D.C. A presentation about the draft report was given at a public meeting, PHMSA's Public Workshop on LNG Regulations, on May 19th, 2016, in Washington, D.C. …" (emphasis added)

The 2018 PHMSA /FERC MEMORANDUM OF UNDERSTANDING

PHMSA is responsible for developing the regulations that specify the means of ensuring public safety in siting LNG terminals. The applicable regulation is 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. The present regulation was developed in the early Eighties to regulate LNG peak shaving and import terminals. Consequently, the present PHMSA regulation does not address the "new" hazards of vapor cloud explosions of heavier-than-methane hydrocarbons that are present in large quantities at LNG export terminals. So, during the period following my comments to FERC in 2015 on the UVCE hazard, and until very recently, I failed to understand why the 2015 JCET DEIS included an address of the UVCE hazard (not required by 49 CFR 193) by presenting the extensive predictions of explosion overpressure for heaver-than-methane hydrocarbon/air clouds that could be formed following accidental release at JCET. I remain uncertain why that action was taken, but I am increasingly concerned that the UVCE hazards present in the operation of LNG export terminals are effectively being ignored. My concern is that the order-of-magnitude-too-low predictions of the overpressures used by FERC to evaluate the VCVE hazard in the environmental impact statements for the JCET might result in the continued dismissal of the importance of this hazard for the JCET.

On August 31, 2018, the Federal Energy Regulatory Commission (FERC) and the Hazardous Materials Safety Administration within the U.S. Department of Transportation announced the signing of an agreement to coordinate the siting and safety review of FERC-jurisdictional LNG facilities. Quoting therefrom:

"The Memorandum of Understanding (MOU) establishes a framework for coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public safety impacts. The MOU provides that PHMSA will review LNG project applications to determine whether a proposed facility complies

with the safety standards set forth in PHMSA's regulations, and that PHMSA will issue a letter to FERC stating its findings regarding such compliance. FERC will then consider PHMSA's compliance findings in its decision on whether a project is in the public interest." (emphasis added)

It is my understanding that the JCET DEIS issued in 2019 does not state that FERC received an LOD (letter of determination) from PHMSA that presented its findings regarding compliance with the safety standards set forth in its regulations. It is further my understanding that the FERC/PHMSA MOU effectively requires PHMSA to issue such an LOD by the time the FEIS is completed.

My review of the Reliability and Safety section of the DEIS disclosed no direct reference to the UVCE hazard. It is as if the problem had either been decided as lacking further need of address or that some further address might be forthcoming by the time the EIS is completed.

I respectfully request that I be provided an answer to the following question: Given PHMSA's announcement in 2016 at the Public Workshop on LNG Regulation that 49 CFR 193 appeared to require updating to cater for the new (UVCE) hazards that attend Export Terminal operations, why has that announcement not led to any further analysis and evaluation in the 2019 JCET DEIS?

Unless that question can be answered satisfactorily, it appears that critical safety recommendations by PHMSA requiring changes to 49 CFR 193, backed up by extensive advice from the scientific expert community, are being ignored.

Who Required the UVCE Hazard to be Addressed in the 2015 JCET DEIS?

The only government source I have found for guidance regarding calculations of overpressure required to be presented in the 2015 JCET DEIS is in "Guidance Manual for Environmental Report Preparation, Volume II, LNG Facility Resource Reports 11 & 13 Supplemental Guidance, DRAFT, December 2015", prepared by FERC. Section 13.H.3, "Hazard Analysis Reports" of that draft appears to be the source of the requirement for explosion overpressure that appeared in the 2015 JCET Environmental Impact Statements. The requirement for explosion overpressures remains in the Guidance Manual for Environmental Report Preparation, FINAL, dated February 2017.

It is my understanding that the Draft FERC document providing guidance to JCET for providing VCE overpressure calculations was not based on the requirements of 49 CFR 193. It appears that FERC may have recognized the need to evaluate the UVCE hazards that could attend the operation of the JCET, and that those hazards should be considered in the JCET DEIS. I have no information about why FERC included the requirement to address UVCE hazards in their Guidance Document for preparation of Environmental Impact Statements. In any case, the "requirement" in FERC's Guidance Manual for Environmental Reports appears to demonstrate FERC's awareness of the importance of addressing the UVCE hazard.

The fact remains that the predictions of overpressure that were provided for the JCET DEIS in 2015 were stated therein to be made with the FLACS model, and although FLACS is approved for vapor dispersion calculations required by 49 CFR 193, it is my understanding that FLACS still has not been either evaluated or approved by PHMSA for explosion overpressure determination. If this is the case, then a major course-correction seems required, because comparisons of those (order-of-magnitude-too-low) overpressure predictions with documented measurements of overpressure data for a large number of UVCE events involving the same hydrocarbons, in similar amounts, and in similar atmospheric conditions, will demonstrate that the predictions utilized in the JCET environmental impact statements are in serious error.

If this problem is not addressed, it appears likely that such errors accompanied by FERC's approval thereof will ignore the scientific expert advice that resulted from the PHMSA Workshop conducted in 2016. The effect will be to ignore extensive accident experience that demonstrates the potential for cascading explosions that could destroy the plant and possibly extend damages to the public beyond the facility boundary.

CONCLUSIONS

49 CFR 193 Liquefied Natural Gas Facilities: Federal Safety Standards does not currently provide for adequate consideration of the hazards of Unconfined Vapor Cloud Explosion (UVCE) hazards that attend LNG Export Terminals handling and storing large quantities of heavier-than-methane hydrocarbons.

PHMSA conducted the Public Workshop on Liquefied Natural Gas (LNG) Regulations in Washington, DC, 19 May 2016. The principal purpose of the Workshop was stated to be the intention to address the need for updating 49 CFR 193 in order to cater for any new hazards that could be involved in siting LNG Export Terminals. The Workshop clearly identified the UVCE hazard as being the most important hazard present at Export Terminals that was not currently addressed adequately by 49 CFR 193.

PHMSA initiated a program to address the needs for changes in the regulation to provide for UVCE hazards. It appears that no progress has been forthcoming.

The new Draft Environmental Impact Statement (DEIS) for the Jordan Cove Export Terminal, just issued, continues to seriously underestimate vapor cloud explosion overpressures (damage) that could occur following credible releases of heavy hydrocarbons at the JCET site. The latest predictions that I am aware of appear to be an order of magnitude lower than are indicated by physical evidence of numerous documented UVCEs that have occurred worldwide with the potential to cause injuries and deaths to persons and result in destruction of the facility.

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are my fourth in a series submitted to the website established for the Public Workshop on Liquefied Natural LNG Regulations conducted in Washington, DC in May 2016. I appreciate the availability of this website for receiving comments from the public relating to the PHMSA's intention to update 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. However, I am very concerned that failure to ensure that the hazards attending LNG export terminals are adequately addressed will have catastrophic consequences.

The Workshop website includes two documents which are critically important because they explain clearly to all stakeholders the critical need for the regulations to be updated and effectively prescribe a path forward that would alleviate my concerns. Unfortunately, the website does not appear to have received the attention it deserves – to date the site has received only about a dozen comments, four of which are mine. The first document clearly defines the principal need that the Workshop was designed to address – a science-based evaluation of severe heavier-than-methane vapor cloud explosion (VCE) hazards that can exist in LNG export terminals. The second document, commissioned by PHMSA and presented at the Workshop, clearly provides that need.

I am concerned that comments that I filed with FERC in 2015 regarding the Environmental Impact Statement for the Jordan Cove Export Terminal in Oregon and the subsequent Health and Safety Executive Report "Review of Vapor Cloud Explosion Incidents" presented at the Workshop in 2016 are being ignored. In my opinion, a potential error in overpressure calculations presented in the Jordan Cove EIS portends the possibility of a VCE explosion that could destroy the plant and endanger the Public beyond the facility boundary.

Excerpts from PHMSA's Statement of Mission (from the Workshop Website)

"Historically, most LNG facilities were peak shavers built to liquefy and store natural gas to be degasified and injected back into the pipeline during periods of peak demand … However, due to the recent abundance of domestic shale gas, LNG export terminals are now being constructed that liquefy vast volumes of natural gas. These facilities require significantly greater quantities of refrigerants to liquefy the natural gas than the amount typically used at peak shavers… Most refrigerant gases and blends used at the export facilities contain ethane, propane, ethylene, and iso-butane and are referred to as heavy hydrocarbons. These gases are similar to gases that have resulted in VCEs at petrochemical facilities…

The understanding of VCEs is evolving. PHMSA recognizes that significant quantities of heavy hydrocarbons present different risks than methane and seeks to better understand that risk. Prior to investigative work on the Buncefield accident, the prevailing understanding was that vapor clouds formed outdoors were unlikely to explode if ignited. Today it is understood that VCEs involving higher hydrocarbons have occurred in outside areas. This paper advances our understanding further. PHMSA sponsored the "Review of Vapour Cloud Explosion Incidents" report with the primary objective to improve the scientific understanding of vapour cloud development and explosion in order to more reliably assess hazards at large Liquid Natural Gas (LNG) export facilities… The aim of reviewing the particular incidents in this report is the extensive forensic evidence available that provides the information needed to study how the vapor cloud formed and ignited, the amount of overpressure exerted, and other information about the mechanism of VCE. This research was performed by the Health and Safety Laboratory (HSL) under a subcontract with the Oak Ridge National Laboratory, a United States Department of Energy (DOE) facility, and was supported by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA and DOE) and the United Kingdom Health and Safety Executive (HSE). The research's objective was to improve understanding of vapor development and explosions in order to more reliably assess hazards and safety measures at facilities that contain significant quantities of heavy hydrocarbons…

The technical review of the report was performed by uncompensated subject matter experts… The purpose of this independent review was to provide candid and critical comments to make the report as sound as possible… The review, comments, and draft manuscript remain confidential to protect the the integrity of the deliberative process. The panel reviewed multiple drafts of the report, held several conference calls, and convened a meeting on May 17th (2016) in Washington, D.C. A presentation about the draft report was given at a public meeting, PHMSA's Public Workshop on LNG Regulations, on May 19th, 2016, in Washington, D.C. …"

Excerpts from the Executive Summary of "Review of Vapour Cloud Explosion Incidents"

"This review of major vapor cloud incidents has been jointly commissioned by the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and the UK Health and Safety Executive (HSE). The primary objective was to improve understanding of vapor cloud development and explosion in order to examine the potential for these hazards to exist or develop at LNG export plants that store substantial quantities of these flammable gases for use in the liquefaction process or as a by-product from the liquefaction …

This review has not found any historical records of LNG (methane) vapor cloud explosions in open areas with severity sufficient to cause secondary damage to tanks and pipes and consequently rapid escalation of an incident from a minor process leak to a major loss of inventory.

On the other hand some LNG sites (especially export sites) also hold substantial amounts of refrigerant gases and blends containing ethane, propane, ethylene and iso-butane. Higher hydrocarbons may also be produced and stored on LNG export sites as by-products of gas condensation. There are numerous examples of Vapor Cloud Explosions (VCEs) in open areas involving these higher molecular weight materials and the storage and use of higher molecular weight hydrocarbons on LNG export sites which may if not managed adequately introduce an additional set of incident scenarios in which VCEs trigger rapid escalation of loss of containment.

This study involves a review of 24 major VCE incidents focusing on source terms, cloud development and explosion mechanics. The incidents studied are split between permanent fuel gas (C2-C4 (e.g. LPG) and volatile liquids C4-C6 (e.g. gasoline). The source terms for leaks of gases and liquids are different but once a stable current of cold heavy vapor forms, the subsequent development of LPG and gasoline clouds are similar…

An important finding from the review is that a high proportion of vapor cloud incidents occurred in nil/low wind conditions. By the term “nil/low wind” we mean a wind that was so weak close to the ground that it only detrained (stripped away) a small proportion of the vapor accumulating around the source … Rather than being picked up and moved downwind, the vapor flow in this case was gravity driven; spreading out in all directions and or following any downward slopes around the source.

In many of the cases examined, 50% (12/24), there is clear evidence from the well-documented transport of vapor in all directions and/or meteorological records that the vapor cloud formed in nil/low wind conditions. In a further 21% (5/24), the pattern of vapor suggests nil/low wind conditions but there is insufficient data available to be sure … incidents in nil/low wind conditions apparently make up the majority of historical records of the most serious VCEs… In nil/low wind conditions the cloud continues to grow throughout the time that the tank takes to empty… The maximum area covered by the flammable cloud is typically several hundred times greater in nil/low winds condition than in light winds.

The implication of this type of analysis is that if the density of ignition sources is constant and quite low in the area around the tank the chances of ignition in nil/low wind conditions would be hundreds of times greater for a given release. This illustrates why nil/low wind conditions dominate records of major vapor cloud incidents even though the weather frequency is low. Losses of containment in nil/low wind conditions are also particularly dangerous because a highly homogeneous cloud can be formed that may spread by gravitational slumping (without significant dilution) for hundreds of meters… A very large cloud that is all close to the stoichiometric ratio increases the risk of flame acceleration to a high pressure regime capable of seriously damaging storage and process facilities, when compared with clouds that are entraining air because of wind-driven dilution. Thjis is because fundamental burning rates fall off rapidly for concentrations away from the stoichiometric . Once a high pressure regime is established explosions are not confined to congested areas of a site. In many of the cases reviewed almost all the footprint of the cloud was exposed to pressures in excess of 2000 mbar (29 psi). In at least one case the cloud detonated, causing extremely severe damage over the area covered by the cloud). (emphasis added)”

When is the LNG Regulation Update Expected?

It has been more than two and a half years since the Public Meeting on LNG Regulation was held. My attempts to get information on the schedule for Regulation updating have not been encouraging. I have learned that PHMSA has addressed the need for a written protocol to assess the verity and utility of the computer-calculated explosion overpressure predictions that were the means of addressing the vapor cloud explosion (VCE) hazard in the Environmental Impact Statement(s) filed for the Jordan Cove Terminal in Oregon. I should note that these comments are directed primarily to the environmental impact statements relating to the Jordan Cove Project, which I have previously commented on; however, the scientific information presented on the Workshop website that I am referring to should be considered applicable to LNG Export Terminals in general. I understand that the development of a written protocol (for explosion model verification) requires that funding be expedited. I also understand the difficulties faced by the Regulatory Agencies in the present political climate. Meanwhile, LNG export terminals are being approved and some are operating. I am concerned that errors are being made in the calculation of overpressures in the design spills that are being considered in environmental impact statements for LNG export terminals now processing applications for siting. Such errors can put these very expensive facilities at risk of severe vapor cloud explosions that could result in cascading loss of containment events that could destroy the facility and present important hazards to the public beyond the plant boundaries. Accordingly, I am convinced of an urgent need for updating of the LNG regulations.

Please let this comment serve as my request that funding be provided as soon as possible to PHMSA to determine whether the calculations now being presented for LNG facility siting can be evaluated by testing against the applicable explosion events documented in the HSE report. In my opinion the HSE report contains sufficient validated scientific data for numerous severe VCEs involving the same or similar fuels and amounts thereof. I believe that a careful, science-based, evaluation of the calculations of overpressures in VCEs that have been presented in the Jordan Cove proceedings using the HSE report will provide a method for dealing with this urgent problem that is not cost prohibitive. I believe the problems underlying my concern have been addressed carefully in the HSE report. I conclude that actions required to alleviate these concerns are doable and can be expedited using the HSE report that has been commissioned by PHMSA .

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are a further addition to my comments to the Public Workshop on Liquefied Natural LNG Regulations site on July 28, 2016 and September 22, 2018.

I stated in my comments of September 22, 2018 that I am very concerned that our current regulatory measures concerning siting of LNG export terminals be developed by decision-makers that are fully informed regarding the public safety impacts involved.

Based on information I have learned since September 22, 2018, I want here to clarify my understanding of the process that took place in the preparation of the Environmental Impact Statements for the Jordan Cove LNG Export Terminal, and I respectfully request that PHMSA inform me of any faults in that understanding.

In 2015 FERC published a draft notice of their intent to update their guidance document on preparation of environmental impact statements. The earlier guidance document (2002) did not include any consideration of explosion overpressure hazards. The draft (dated 2015) clearly specified the direction to applicants to prepare calculations of VCE explosion overpressures that could result following the Design Spills considered, and the draft was approved and issued in 2017 – still containing the directions to the applicant to prepare the explosion overpressure hazards calculations.

To my knowledge, PHMSA's regulations on LNG Terminal siting did not in 2015 and still do not require Vapor Cloud Explosion (VCR) overpressure calculations.

The FLACS Model was approved for vapor cloud dispersion exclusion zones by PHMSA based on FLACS' satisfactorily meeting the requirement of PHMSA's written protocol.

The written protocol used to approve FLACS for calculating vapor cloud dispersion zones does not address the suitability of FLACS for calculating VCE overpressures.

I am very concerned that the afore-mentioned information could indicate that the FLACS model used for calculating the VCE overpressures presented in the Jordan Cove LNG Export Terminal Environmental Impact Statements has not received adequate scientific peer review.

I appreciate this site remaining available for comments relating to the 2016 PHMSA Public Workshop on Liquefied Natural Gas (LNG) Regulations.

Comment by Jerry Havens
Distinguished Professor Emeritus
University of Arkansas

I am speaking as a concerned scientist and citizen.
My comments are not to be attributed to the University of Arkansas.

These comments are an expansion of my earlier comments to the Public Workshop on Liquefied Natural LNG Regulations site on July 28, 2016, which I stand by. They are also intended as a response to the joint news release of August 31, 2018 by PHMSA and FERC:

FERC, PHMSA Sign MOU to Coordinate LNG Reviews

Quoting the MOU, "The MOU establishes a framework for coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public safety impacts ".

I understand the importance to us all of expeditious and timely handling of LNG Export Terminal applications, but I am very concerned that our current regulatory measures be developed by decision-makers that are fully informed regarding the public safety impacts involved. I realize the gravity of this statement, and I have struggled with the decision to put such questions of uncertainty on the table. But I have been unable to satisfy myself that my concerns are unwarranted. Therefore, I appreciate this opportunity to state my concerns.

Please let me repeat that I stand fully behind the comments I submitted to this site on July 28, 2016, as well as all of my previous comments submitted to FERC and PHMSA. But more importantly, I want to clearly identify here my increasing concerns that our regulatory process is failing to satisfactorily consider fully the accident consequences that attend the operation of LNG Export Terminals that must be considered in the public interest. Please consider the following statements, which I trust are factual. If PHMSA notifies me that I am in error, I will promptly refile accordingly.

- The current LNG regulation 49 CFR 193 was developed for application to the evaluation of hazards attending Import Facilities.
- 49 CFR identifies only two hazard exclusion zone requirements; a vapor dispersion zone and a fire radiation zone. The regulations require that the maximum lateral extent of these zones must not exceed the distance to the property boundary.
- The current regulation does not address vapor cloud explosion hazards. My understanding of the basis for this policy is the long-accepted premise that LNG vapor (being essentially methane, that is, not containing heavier (higher molecular weight) hydrocarbons such as propane, butane, etc.), will not explode if uncontained.

- For import terminals, there are normally no situations where there is significant risk of release of large amounts of heavier-than-methane hydrocarbons.
- But, for export terminals, the gases entering the facility for liquefaction may (and typically do) contain significant amounts of high-explosion-risk hydrocarbons that must be stored and handled, thus presenting new risks not ordinarily attending import terminals.
- <u>The requirement for only two exclusion zones, dispersion and thermal radiation zones, for import terminals does not address the risks of explosion of unconfined gas air clouds that can occur at export terminals.</u>
- My comments to FERC and PHMSA on this subject have been directed thus far primarily to the Jordan Cove Export Terminal proposed for the coast of Oregon. The remaining points in these comments are largely presented for consideration with the Jordan Cove Facility only. However, it should be anticipated that such hazards could attend any of the LNG export terminals currently operating or under consideration throughout the world.
- As I understand it, there is no requirement at present in 49 CFR 193 to address the unconfined vapor cloud explosion (UVCE) risk.
- However, as exemplified by the Draft and Final Environmental Impact Statements for Jordan Cove, the applicants included calculations to provide for the formation of very large clouds of heavier hydrocarbon gases than methane <u>which are known to cause damaging explosion overpressures</u>. It is my understanding that the calculation of the overpressures was done with a Computer Code called FLACS. The results of the calculations were then used to justify the statement in the Environmental Impact Statements that the explosion damage would not extend off-site. Along with Professor James Venart of the University of New Brunswick (now deceased) I filed comments with FERC questioning the accuracy of those conclusions in 2015.
- Subsequently, PHMSA held a public workshop in Washington in mid-2016 which announced PHMSA's intent to consider the need for updating the LNG regulations for proper consideration of the hazards that attend LNG export terminal operations.

The Current Situation (as I understand it)

It appears that the FLACS Computer Model used in support of Jordan Cove applications was used to calculate the vapor cloud explosion overpressures that could have been realized for the design spills considered. My understanding is that the calculations using the FLACS model are important to the final decision by FERC to grant approval to both the DEIS and the FEIS for Jordan Cove. For various reasons, the project did not proceed, but it has been announced that a new DEIS will be issued in February of 2019.

In view of the importance of the facts presented, coupled with the policy now adopted by PHMSA for such codes as FLACS to be designated **Proprietary** using their designation as Critical Energy Infrastructure Information (CEII), it appears to me that the public interest is not being served by the Agency's failure to sufficiently investigate the scientific validity of FLACS for determining the damage that might result from the very spills of heavier than methane hydrocarbons that Jordan Cove argued could be released, specifically mixed refrigerant hydrocarbons and ethylene, both of which have been shown to cause violent Unconfined Vapor Cloud Explosions.

Here are three more inputs which I believe support my concerns:

- LNG Regulation 49 CFR 193 is based on the determination of the extents of exclusion zones for vapor dispersion and fire (thermal) radiation using mathematical models which must be approved by PHMSA.
- As I understand it, vapor dispersion models are now approved by PHMSA only if the models meet the requirements of PHMSA-specified written protocols designed for the purpose.
- <u>To my knowledge there has not been made available to the public a protocol that must be met for PHMSA's approval for the use of FLACS to predict vapor cloud explosion overpressures</u>. This leaves me with the concern that the FLACS model has not been sufficiently evaluated for such regulatory use, considering the very high stakes involved.

Thank you for the opportunity to express my concerns about this situation, which I believe is of critical importance to us all.

Comment by Jerry Havens
Distinguished Professor of Chemical Engineering
University of Arkansas

<u>I am speaking as a concerned scientist.</u>
<u>My comments are not to be attributed to the University of Arkansas.</u>

I attended the LNG workshop at DOT Headquarters in Washington on May 18 and 19, 2016. My comments are directed to the plans previewed by PHMSA at the workshop for updating the federal regulatory requirements for safe siting of LNG facilities; especially relating to the workshop presentations made by Drs. Graham Atkinson and Simon Gant of the British Health and Safety Laboratories (HSL) regarding predictive modeling of flammable vapor cloud formation, dispersion, and explosion hazards.

I understand that HSL is under contract to PHMSA to provide an assessment of specific needs that should be addressed by PHMSA for its planned updating of LNG Regulation 49 CFR 193. I do not know the specific requirements of the contract with HSL, but it seemed strongly suggested at the workshop that HSL is considering at least two critical needs for LNG facility siting regulation evaluation and updating:

- Unresolved questions about the potential at LNG storage terminals for unconfined vapor cloud explosion (UVCE), with emphasis on the increased potential for severe explosions involving heavier-than-methane hydrocarbons used and stored in large amounts in LNG export terminals. (Workshop presentation by Dr. Atkinson)
- Protocols for approval of mathematical models for LNG vapor cloud formation, dispersion, and explosion potential, particularly for heavier-than-methane hydrocarbons. (Workshop presentation by Dr. Gant)

My comments focus on the methods used to determine consequences of UVCEs that could follow the design spills required to be considered by 49 CFR 193. I believe the following three issues (in caps), all of which are closely coupled in the determination of vapor cloud explosion potential, are of highest priority for updating the LNG regulations.

MATHEMATICAL MODELS FOR VAPOR DISPERSION CONFINED BY FENCES AND UVCE OVERPRESSURE POTENTIAL REQUIRE THOROUGH SCIENTIFIC VETTING

The main purpose of my comments is to request PHMSA to address concerns that have been raised that some of the mathematical modeling methods currently in use can produce results that severely underestimate vapor cloud explosion hazards (consequences) to the public. I am very concerned that PHMSA's current procedure for determining the hazards attending large-scale LNG Export Terminals, including the present protocol for approval of vapor dispersion models for such use, is seriously flawed, particularly regarding UVCE hazards.

Proprietary Models

The current model approval process relies on provision to PHMSA by the applicant (for model approval) of evidence that the proposed model meets PHMSA requirements for scientific correctness as well as requirements for satisfactory model agreement with a PHMSA supplied list of field and laboratory experiments that have been documented. The most serious flaw in the current procedure, in my opinion, is that because the protocol allows approval of modeling methods that are proprietary, and thus not subject to independent scientific-peer review, neither PHMSA nor the public can confidently determine whether the models are suitable for purpose. The result is that the public is not provided the following information about the hazard-modeling process, all of which is necessary to make a science-based evaluation of the model predictions that form the basis for FERC's approval or disapproval of proposed LNG terminals:

- Details of data input to the model(s),
- Detailed results produced by the model(s), and,
- most importantly, a transparent description of the methods used in the models that is suitable for examination and scientific review to ensure that the methods are not used improperly.

The use of proprietary models denies the public an effective means of ensuring that errors in model application are not committed accidentally or intentionally. Such a process portends danger to the public. There is no question that the hazards attending the handling and storage of extremely large quantities of potentially flammable/explosive materials in LNG facilities, if the hazard determinations are not accurate, could result in catastrophic damages extending beyond facility boundaries.

PHMSA has a single means of ensuring that the decisions for approval of the safety provisions claimed are not subject to error – a scientific peer review process. There must be a means developed to insure that the public is provided information sufficient to independently verify the accuracy and applicability of the model predictions that determine FERC's decision for or against LNG facility approval. The importance of requirements for model transparency can only increase as the scientific tools for predicting hazardous materials risks and consequences become more complex and difficult for evaluation by the regulators and the public.

Past Experience: "Sub-Model" SOURCE5

A brief review of one of PHMSA's documented actions taken to correct misuse of hazard-models illustrates the difficulties the agency faces in enforcement of model use that is based on correct science and is accurate. The "case" described below also provides a pertinent example of the critical need to ensure that so-called "sub-models" (subordinate parts of the parent models) that are required to quantify the risk and/or consequences of the "design" spill are also based on correct science and are accurate. This is particularly important presently; some of the issues that I believe are now being handled incorrectly and which were described in my comments to FERC in January/February 2015 regarding the DEIS for the Jordan Cove LNG Export Terminal are due to use of such sub-models.

The vapor dispersion models approved for determination of vapor cloud exclusion zones by PHMSA require specification as input the rate at which the gas enters the atmosphere. Historically, the largest "design spills" for which vapor cloud exclusion zones must be predicted are liquid spills into impoundments, necessitating estimation of the evaporation rate from the LNG (liquid) released as input to the vapor dispersion model. Until about 2010, during which time the LNG vapor dispersion model DEGADIS was used widely, a sub-program called SOURCE5 was used to compute gas input rate to the dispersion model. There appeared statements in the scientific literature as well as comments to Draft Environmental Impact Statements that SOURCE5 contained assumptions that were erroneous and that resulted in severe underestimation of the "source term" (the gas rate introduced to the atmosphere) which led to severely underestimated vapor cloud dispersion distances.

PHMSA responded and processes were put in place to provide scientific review of several sub-models, including SOURCE5. One of the resulting scientific reports that contributed to PHMSA's decision to prohibit further use of SOURCE5 was prepared by the British Health and Safety Laboratory (HSL). See Ref. 1 below. For brevity, I quote a single brief statement from Appendix A of HSL's report which I believe says everything that is necessary to justify, indeed require, PHMSA's decision to prohibit further use of SOURCE5:

> *In summary we find that the suite of models embodied in SOURCE5 do not have a sound physical basis. In fact it is doubtful that one can get an accurate picture of a scenario as complicated as those considered here if one restricts oneself to simple algebraic equations such as those considered by SOURCE5. Some of the predictions of the model, especially the lack of dilution of the vapour before it achieves the bund wall height, are expected to result in markedly optimistic prediction of hazards.*

I used this short excerpt because it so effectively summarized HSL's finding. Lest the reader be misled by the brevity and straightforward simplicity of this statement that justified PHMSA prohibiting further use of SOURCE5, I think a few remarks are in order. Readers willing to take the time to examine the HSL Report from which the excerpt is quoted will find that the examination of the model by HSL was thorough and painstaking. The expertise and knowledge required for an assessment of complex mathematical models resides in relatively few independent organizations, and the resulting action prohibiting further use of SOURCE5 could not have been achieved without PHMSA's request to a neutral scientific body for advice and interpretation. I appreciate the agency's concern that the amount of time and effort required by the model evaluation by HSL was expensive to the U.S. taxpayer. However, such costs are necessary as part of any government regulatory process that relies on expert scientific advice for decision making, particularly if those decisions directly impact public safety. Without such actions taken by the regulatory authority, the public cannot be confident of predictions that FERC accepts to approve or disapprove a facility.

THE PRACTICE OF CONFINEMENT OF VAPOR CLOUDS WITH GAS-IMPERMEABLE FENCES SHOULD BE EVALUATED FOR POTENTIAL TO INCREASE EXPLOSION DAMAGE

The use of gas-impervious vapor fences is relatively new to the industry; it appears to be resulting more frequently associated with requests for approval for siting of very large facilities which cannot economically provide satisfactory exclusion distances to the facility property line without resort to such "vapor cloud mitigation practices". The majority of LNG Export Terminals now being considered have requested approval by FERC of vapor-impervious fences placed strategically to limit flammable vapor cloud travel beyond the applicant's property line. Such practices raise important (unanswered) questions about the increase in the severity of vapor cloud explosions that can result from such partial confinement. Based on my review of the Jordan Cove project DEIS, it appears that FERC has not considered the potential of such fences, some of which are 40 feet tall and constructed with reinforced concrete, to increase explosion overpressure damage. In my opinion this neglect of explosion science knowledge is wrong.

CURRENT MODELS FOR EXPLOSION DAMAGE OF VAPOR CLOUDS ARE INSUFFICIENTLY TESTED AND MAY LEAD TO NONCONSERVATIVE HAZARD PREDICTIONS

After I learned of the planned PHMSA workshop and that PHMSA had contracted with HSL to evaluate some of the concerns I had raised in my comments to FERC, I developed a better understanding of the situation which I believe should be considered by PHMSA as they proceed with the regulation updating process. I believe the issues described here deserve highest priority, since unconfined vapor cloud explosions involving heavier-than-methane hydrocarbons handled and stored in large quantities in LNG export facilities pose the potential for catastrophic cascading explosion damages resulting in complete destruction of the facility and potential for danger to the public beyond the facility boundaries.

Focusing on Jordan Cove EIS Critical Issues: Effects of Vapor Fences and Use of Proprietary Models to Predict Explosion Overpressure

Expert advice for preparation of draft environmental impact statements is generally provided to applicants for siting approval (such as Jordan Cove) by consultants who are practiced in making such determinations using computer modeling methods. Such calculations are now almost exclusively made using complex mathematical modeling tools – the use of computational fluid dynamics (CFD) computer models has become widespread in the LNG industry/regulatory community in the last two decades. This practice, however sophisticated and rapidly developing it may be, is relatively new and untested for application to the strongly coupled complex phenomena of atmospheric dispersion and combustion/explosion dynamics. Experimental verifications of such model predictions as complex as those currently appearing in environmental impact statements is increasingly expensive and difficult to achieve.

In my opinion, the reality of the situation is this: The prediction of explosion overpressure damage that could result if a very large design spill formed a flammable vapor cloud in near-calm conditions and confined by vapor fences is presently fraught with uncertainty; so much so that the scientific community has insufficient confidence in such predictions unless they are verified, at least in part, by experiment. But these new "complex" models are the product of private research and development efforts, in the present case by consulting companies that must deal directly (for the project applicant) with PHMSA and FERC. The result is that such tools are now being approved by PHMSA with a proprietary designation. This is understandable, if not necessarily justified, as the companies are motivated to protect their investment in the required model development process.

It is this author's experience that until the current model protocol process was instituted (accepting proprietary models for regulatory use), there has always been a strong reluctance by regulators to allow such models that are not available (at reasonable cost) to the public, or the public's agent, for careful scientific scrutiny. SOURCE5, although developed by private interests, was not prohibitively expensive and could be obtained for careful analysis with a reasonable effort by the public. That availability enabled the criticisms that led to the model's careful scientific vetting and the prohibition of its further use. The new complex models being adopted are prohibitively expensive to the public and protected as proprietary as well. There must be some means of ensuring that such complex, untested, calculations are thoroughly vetted by independent scientific parties responsible to PHMSA. In my opinion, proceeding with the current hazard evaluation processes now being approved by FERC cannot be justified.

Low or No--Wind Condition Concerns Made Worse with Cloud Confinement

Revisiting the Jordan Cove DEIS in preparation of these comments, I verified that the vapor cloud travel distances that were determined using the recently approved FLACS model, essentially none of which reach beyond the JC property lines, resulted not from dispersion (or lack thereof) but from the use of vapor fences that confine the cloud to the property controlled by the applicant. The vapor cloud does not proceed beyond the boundaries because it is stopped by a vapor fence. Because the cloud cannot penetrate the fence, it accumulates on the site. Although the fences are not continuous (laterally), they prevent the cloud from advancing beyond most of the boundaries. The result is confinement of the gas on the site, where the depth (thickness) tends to increase until the spill ends and the liquid all evaporates. Then, under very low or no-wind conditions, the gas cloud pretty much sits there (which can be a long time if there is no wind to increase vertical diffusion of the gas) unless it is ignited. But, if it is ignited and the flammable concentration range of the gas includes large parts of the cloud, the condition is set up for a catastrophic explosion.

The Volume of the Gas Cloud that is within the Flammable Concentration Range is a Strong Determinant of the Damaging Explosion Overpressure

The confinement of the cloud when it is formed with very little wind (to increase dispersion) can result in the cloud becoming highly concentrated (in flammable gas) throughout. In all four of the catastrophic explosions described in my comments to FERC (and those described by Dr. Atkinson at the Workshop), there were very large parts of the cloud with gas concentrations in the flammable range. The gas concentration distribution in the cloud strongly determines the severity of the fire or explosion that can result if the cloud is ignited. If the entire cloud is below the lower flammability concentration of the gas, none of it will ignite and there will be no fire or explosion. If the source of ignition is in a region of the cloud where the gas concentration is above the upper flammability limit, ignition will not occur at that location. If ignition occurs in a cloud region where the concentration lies between these limits and there are nearby regions where there are higher concentrations (above the upper flammability limit) the cloud will continue to burn through those regions. In any case the flame advance will only be stopped when the concentration of the cloud (at that location) drops below the lower flammable limit.

Revisiting FLACS and Sub-Model Q9 Used for Jordan Cove EIS

There exists evidence in the open scientific literature that the FLACS vapor-dispersion mathematical model, which includes a specific sub-model called Q9 that is used in part to calculate explosive overpressures, has not been subjected to a satisfactory scientific peer-review process designed to prevent its misuse. In preparation for these comments, I found a publication in the Institution of Chemical Engineers (IChemE) Symposium Series which presents an evaluation of the combined use of FLACS and Q9 for explosion modeling (See Ref. 2 below).

There are striking similarities in the IChemE paper with statements that appeared in criticisms of SOURCE5. Again, for brevity, I have selected brief comments from the IChemE paper about Q9 that indicate serious questions about its overall applicability to the prediction of UVCE explosion overpressure damage in complex plant environments:

> *Q9 is a volume measure which accounts for the effects of gas concentration by weighting the volume with the effect of burning velocity and expansion ratio. Experiments showed that burning velocity varies with concentration … For hydrocarbons, burning velocity is maximum at or near stoichiometric concentration of 1 and dropping off rapidly as gas concentration is rich … or lean …, reaching zero at UFL and LFL.*
>
> *We found that Q9 measures are being used increasingly by consultants. We are concerned that there has not been work to verify that this approach is indeed correct. Our observation is that there appears to be little fundamental understanding of the Q9 measures by consultants we encountered. Its application is based on a belief that since there is a varying gas concentration in a gas cloud formed from pressurized gas release, assuming a uniform gas cloud concentration is thus 'over-conservative', and using Q9 would remove this perceived 'over-conservatism'. As we see… this is not necessarily so.*
>
> *Superficially, Q9 seems to be the most accurate measure out of the three (we reviewed) as it accounts for the well known effect of gas concentration on flame speed and expansion ratio. It may be a surprise that our results showed that the Q9 measure performs poorly. … one should not confuse complexity and accuracy.*
>
> *Size of the gas cloud – Limiting the flammable gas cloud to a smaller effective volume reduces the effect of flame acceleration over a larger distance and over a longer period of time that that produced by larger cloud volumes and could lead to lower and the wrong distribution of overpressure …. Another reason for psssible underestimation of flammable volume is that volumes with rich gas mixtures can be diluted with air or with lean gas mixtures during the course of a gas explosion, rendering the rich mixture closer to the stoichiometric ratio of 1. Applying the Q9 method blindly, it is possible to reach a conclusion that a very large leak of flammable gas would not pose a hazard* (emphasis added).
>
> *Any methods used should be verified against experimental data as far as possible. It should be the duty of the model developer or user of the model to verify any new methods against available data …*
>
> *This work does not support the use of Q9* (emphasis added).

While the referenced IChemE Symposium paper is not equivalent to a thorough scientific peer review, it does qualify as an Industry/Academia-led evaluation of current methods for determining flammable gas volumes to be considered in explosion modelling. Most importantly, the paper provides results of a technical expert-evaluation of the Q9 model for estimating equivalent stoichiometric volumes of the flammable cloud volumes that were predicted for the heavy hydrocarbon design spills presented in the Jordan Cove Export Terminal EIS. Similar queries about SOURCE5 were dealt with by PHMSA's request to an independent scientific body for assessment. I believe the questions raised here about Q9 (as used with FLACS) deserve similar scrutiny, and I hope that PHMSA will commission such a review.

A Closing Comment on Accidental vs. Intentional Events

There were suggestions during the Workshop that incorporation of quantitative risk assessment (QRA) procedures were being considered by PHMSA for updating 49 CFR 193, perhaps by incorporation of LNG-QRA procedures in NFPA 59A.

I believe it is just as important that the regulations begin to address the burgeoning problem of the potential for intentional acts against LNG facilities to cause extremely serious fire and explosion cascading events.

It is clear that reliance on design of LNG facilities to minimize the probability (measure of likelihood) of accidental occurrences is turned on its head when intentional acts are considered. A simple fact plagues all of the energy industry, including the nuclear power and weapons sectors; it is relatively easy to assemble an explosive device that can be made to explode. Designing the same device to ensure that it doesn't explode is another matter entirely.

We can start by doing a better job in applying our scientific knowledge to minimize the extent to which we provide opportunities to those inclined to take advantage. The incorrect use of our scientific tools, so as to mistakenly conclude that the design under consideration is a benign one, leads us in the wrong direction.

Conclusions

The concerns laid out here exemplify why it is impossible for complex mathematical models used in regulatory determinations of questions bearing on public safety, in the absence of transparent independent scientific review, to be fairly and adequately vetted for such use. These concerns were laid out by Professor Jim Venart, now deceased, and me in response to the Draft Environmental Statement (DEIS) for the proposed Jordan Cove LNG Export Terminal in Coos Bay, Oregon. See Ref 3 and 4. I stand by my comments submitted to FERC, which I subsequently provided PHMSA for their information. While FERC acknowledged my comments when the FEIS was issued for the Jordan Cove Export Terminal Project, their reply was unsatisfactory in that it did not address the technical questions for which I had requested answers.

This is more than a debate about scientific theories of the hazards of UVCEs. It is not about "opinions" regarding the hazards of UVCE. My comments to FERC provided verified information that at least four catastrophic UVCE events, all occurring under conditions that clearly justify their description as worst-case accidents (therefore normally considered highly improbable), have occurred in the past decade. See Ref 3 and 4. Those incidents, and additional ones, were also described by Dr. Atkinson at the workshop.

There must be increased transparency of PHMSA approved mathematical modeling methods, especially those used for public-safety-regulation purposes, to prevent the public being misled. In the absence of such transparency there is little likelihood that more detailed and extensive alterations to the regulation will address the primary problem underlying these concerns.

So, my comments focus on a single question - Are the mathematical models which are being used as a basis for approving construction of LNG terminals, with the present focus on Export rather than import, being subjected to the necessary scientific scrutiny to ensure that the hazards involved are being correctly identified? I do not believe they are.

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Exhibit 77

https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/

WILLIAMS COMPANIES FAILED TO PROTECT EMPLOYEES IN PLYMOUTH LNG EXPLOSION

The natural gas company eyeing other Northwest projects has a history of unsafe work conditions.

Two employees were inside the compressor building (rear) at the time of the explosion. One sustained severe injuries. by Washington Utilities and Transportation Commission (Used with permission.)

Author: **Tarika Powell**
(@) on June 3, 2016 at 6:30 am

This article is part of the series Fracked Fuel & Petrochemical Projects in the Pacific Northwest

Two years ago, an explosion at a liquefied natural gas (LNG) plant in eastern Washington forced hundreds to evacuate their homes, injured five workers, and caused $69 million in damages. It was one in a string of accidents at The Williams Companies' natural gas facilities that in the last three years has killed five workers and injured at least 120 people.

Through a public records request, Sightline obtained documents from the Washington Department of Labor and Industries (Washington L&I), which conducted an investigation into the safety of employees at the Plymouth plant where the explosion occurred. The agency found that Williams endangered its employees, lacked an adequate emergency response plan, and had deficient safety training. The company's track record—not just in the Northwest, but throughout the US—reveals a pattern of failing to heed safety regulations. It also illustrates why we should not underestimate the fire and explosion hazards of natural gas processing plants such as LNG facilities.

The Williams Plymouth LNG explosion

The explosion happened shortly after 8:00 a.m. on March 31, 2014 at the Plymouth LNG plant in eastern Washington, about 30 miles south of the Tri-Cities, where the company stores natural gas in liquid form in two 14-million-gallon tanks. Natural gas ignited inside the LNG processing equipment, creating a "rolling detonation" that generated a mushroom-shaped cloud and large fire. Members of the public felt the rumble of the explosion up to six miles away, and employees near the explosion were knocked off their feet by its force. Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

The blast completely fragmented a large piece of the natural gas processing equipment called an adsorber, propelling 250 pounds of debris and shrapnel up to 900 feet away and injuring 5 employees. One employee's injuries were so extensive that a coworker who helped him evacuate the grounds did not initially recognize him. The explosion caused extensive physical damage to buildings and electrical equipment and even bent the BNSF rail line near the perimeter of the facility's property.

Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

To make matters worse, on the morning of the explosion, plant operators had shut down two safety monitoring systems. Facility operators disabled both the system that detects gas releases and the emergency shutdown system, which is designed to put facility equipment in "safe mode" should the plant experience hazardous conditions.

Shutting down these systems disabled detectors that would have automatically shut down the plant in an emergency. Instead, employees who were trying to flee the site had to locate and manually pull two separate emergency shutdown switches. Shutting down the systems may have also disabled the plant's alarms, which explains why many employees did not hear alarms after the explosion.

The last remaining employees on site were able to successfully engage the emergency shutdown only after realizing that the system had been disabled. While the shutdown stopped at least one gas leak, other leaks continued for more than 24 hours. Shrapnel from the explosion had pierced multiple gas pipes as well as one of the facility's two 90-foot-tall LNG tanks, resulting in a "roaring noise" as pressurized gas escaped from multiple locations on site. Residents within a two-mile radius were evacuated to the local fairgrounds, but not before the smell of gas had spread at least a quarter-mile from the plant.

Employees evacuated to the nearest fire station, but officials in charge of responding to the incident asked three Williams workers to reenter the premises multiple times while gas continued to leak so they could help plug, patch, or stop the leaks by closing valves at the site. The shutdown valves employees used to stop the leaks were 150 to 450 feet from the original explosion and fire, the area with the highest potential for exposure to hazards. While these employees rather selflessly agreed to assist, it was against the law to put them back into the "hot zone," the portion of a hazard site that is immediately dangerous to life and health, because Williams had not given them adequate emergency training.

Fires burn at site of Plymouth LNG explosion. by Washington Utilities and Transportation Commission (Used with permission.)

A disaster months in the making

Notably, plant operators had set the explosion in motion several months earlier, in November 2013, when they closed off the end of a pipeline with plastic and tape rather than proper sealing equipment, a move that allowed an explosive mixture of air and gas to enter the LNG processing system.

Next, system operators, following the company's written procedures, failed to properly purge excess oxygen from the equipment. The procedure for purging oxygen did not meet industry standards, and investigators with the Washington Utilities and Transportation Commission (UTC) later determined that the instruction manual lacked details that were clear enough for employees to follow with consistent and safe results. The Pipeline and Hazardous Materials Safety Administration's safety violation report notes that the company had been using the inadequate oxygen purge procedure for many years.

Williams' deficient safety training compounded this negligence. Federal workplace safety and health standards require Williams to adequately train employees for emergency response before asking them to participate in a real emergency scenario. To ensure their safety, only employees who have been highly trained in hazardous materials emergency response are permitted to enter a hazard site for the purpose of stopping a gas release. Guidance by the National Fire Protection Association and the International Association of Fire Chiefs supports these laws.

Yet Williams failed to adequately train its workers to enter the area of immediate threat, thereby gravely endangering them. On paper, the company's procedures align with workplace safety regulations, stating that only employees who have received advanced training in hazardous materials and emergency response will be sent into a hot zone or participate in an actual emergency response operation. In fact, the employees who were sent into the hot zone had not received the legally required training, so facility managers had a duty to make sure they remained evacuated from the site.

These workers faced many hazards in the hot zone: in addition to the gas leaking from pipes and the LNG storage tank, the facility houses liquid propane and butane tanks that each hold about 3,000 gallons and that are susceptible to expanding vapor explosions in circumstances such as those that followed the Plymouth explosion. The pipeline leak closest to the original explosion abutted a warehouse that gas had most likely entered, and as a 2010 overview of LNG properties and hazards notes, "explosions occur with noticeable frequency from a buildup of natural gas vapors indoors."

In addition to failing to adequately train its employees, Williams did not provide them with the protective clothing and equipment necessary to enter an area containing fire and explosion hazards. Workplace safety laws require that employers provide appropriate protective equipment to any personnel who enter a hazardous site, including a respirator and protective clothing that would cover all parts of the body that could be harmed by the hazard. While firefighters wore full protective gear and respirators, Williams provided only one of the employees with comparable protective equipment to enter the hot zone. Another was only given a flame-resistant shirt and pants, while the third employee was only provided with a flame-resistant shirt.

Washington L&I found that Williams placed its employees in close proximity to gas leaks that were likely to cause injury from a fire or explosion. The state determined that Williams' emergency response plan was not effective in practice because the company only provided limited emergency response training. Further, the agency noted deficiencies in Williams' written health and safety programs. Washington L&I fined Williams $1,000 (later adjusted down to $300) and ordered the company to correct the violations by giving the employees appropriate emergency response and hazardous materials training.

Rocky inspection record at Plymouth LNG

Past inspections at the eastern Washington facility foreshadowed Williams' lack of preparation for fire hazards or natural gas releases. A 2002 inspection by the UTC found fully ten areas of concern at the facility. Some of the fire detectors were too weak to detect hazards more than a couple feet from the equipment, and another was out of alignment with the area it was supposed to monitor. The company's procedures did not require that gas detection systems meet the National Fire Protection Association's minimum LNG fire protection requirements, and plant operators were not able to provide documentation that staff regularly checked the equipment for leaks. Further, the company lacked procedures to minimize the recurrence of safety incidents.

A V-shaped ice formation develops above the puncture on Plymouth LNG tank while pipe (lower left) spews LNG and gas vapor. By Washington Utilities and Transportation Commission (Used with permission.)

In other failings, a 2007 inspection by the UTC noted that for at least two years, Williams technicians had not correctly read the output for one of the cathodic protection devices, which help prevent leaks by monitoring corrosion in metal structures such as liquid gas storage tanks and pipes. They hadn't done so because the technicians themselves were confused about the configuration of the equipment.

In 2008, the UTC issued a violation to facility operators because they did not inspect and test fire control systems within six-month intervals, as required by federal LNG standards. Two of Williams' senior officials at the plant were "surprised that there was no grace period in the code" that allowed them to exceed the six-month minimum requirement for testing fire equipment.

Company's workplace safety problems have triggered federal probes

The Williams Companies is a natural gas corporation with hundreds of miles of pipeline in the western states and along the Atlantic coast. The company was set to build 232 miles of pipeline through Oregon for the Jordan Cove LNG export project, which federal regulators rejected in March 2016, and 85 miles of pipeline for the proposed Oregon LNG export facility, which developers withdrew from consideration in April 2016.

Both federal and state agencies have fined the company on numerous occasions for poor operations of natural gas plants and pipelines, but in the past three years, an alarming number of explosions and fires have broken out at The Williams Companies' natural gas and petrochemicals facilities, suggesting a pattern of recklessness that reaches far beyond Plymouth.

For example, a flash fire at one of the company's natural gas compression facilities injured fifteen people in New Jersey in May 2013. That same month, a Pennsylvania gas compressor station caught fire with eleven employees on site. In June 2013, an explosion at a Louisiana olefins plant killed two workers and injured more than 100 others. Then in October 2013, another explosion killed three contractors at a different Louisiana facility. A month after the March 2014 explosion at Plymouth LNG, an explosion at a Williams gas gathering facility in a small Wyoming town forced residents to evacuate.

The Occupational Safety and Health Administration found that the company failed in its responsibility to find and fix safety violations and ensure the safety of workers at its Louisiana olefins plant. The string of accidents also triggered the US Chemical Safety

Board to initiate a federal probe into Williams' safety practices. That investigation has been slow-going.

Williams resumes business as usual in Washington

Williams failed to properly train and equip its employees for emergency response, and it did not adequately coordinate with local first responders so that they could address the hazard without endangering employees. The company's failure increased the dangers of the hazard not only for employees and first responders, but also for the broader community.

There is reason to worry The Williams Companies will continue to shirk safety standards.

After paying a very small fine for its actions, Williams has moved forward. The company has now completed all the repairs necessary to resume full operations at Plymouth, and it is slated to build the pipeline for a proposed methanol facility at the Port of Kalama, Washington. But the company's record, along with ongoing investigations into the company's practices by Washington L&I and the UTC, demonstrate there is reason to worry The Williams Companies will continue to shirk safety standards—potentially endangering Williams' employees and nearby communities once again.

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