EMERGING RISKS TASK FORCE REPORT – 2013

Project Overview

Task Force Charter

"The petroleum products moving through the Northwest (NW) are changing in product type, transportation mode and quantity. This task force (TF) will look at those changes and determine how they will impact oil spill risks in the NW. Specific tasks include: (1) Decide how to represent the current and proposed transportation risk picture for AOR (Area of Responsibility). Recommend dividing into sub-taskforces (pipeline, rail, marine); (2) Determine characteristics, response strategies and safety for non-traditional products such as: Oil Sands, coal, residual fuel oil, LNG (liquefied natural gas), biodiesel and synthetic fuels."

This was an information-gathering TF charged to study changing traffic patterns and volumes of oil and other fuels entering and exiting the region. The Task Force's diverse membership endeavored to capture a high-level snapshot of such activity in the spring/summer of 2013. The information presented ranges in fidelity because some contributors relied upon single Internet searches for their reports whilst others more familiar with the subject matter cited multiple sources for their work. We understand that research based on a single Internet search is always susceptible to error/bias. We further understand that any findings we present can and will likely change. Economic conditions based on supply and demand are unpredictable, certainly those relating to commodities addressed in this report are. For example, the United States' LNG market has gone full circle. Five years ago there were plans to import LNG. Today we are a country awash in LNG, looking to export the product. Our 2013 picture will look totally different in a year, possibly as soon as the next step of this project, the Vessel Traffic Risk Assessment, is completed. In addition, a year from now ports, refineries and governments will have built, delayed or cancelled projects seen as "on the books" today. In other words, caveat lector.

Sections of this document will be inserted into the 2014 Northwest Area Contingency Plan update.

Washington State Petroleum Association (WSPA) members' input provided historical details on Group V oil movement in our region. New details will likely arise that will allow future Area Committees to further address these heavier products. Though WSPA's input was narrow, they made it clear that " [WSPA] is unable to critique, comment on or verify much of the factual material in the Draft. Therefore, [WSPA's] participation in this effort should not be construed as adopting or endorsing this Draft or any subsequent Draft unless [WSPA] does so in writing."

Scott Knutson, Task Force Chair

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I. FINDINGS: CRUDE OIL

A. Transportation picture

The U.S. crude-by-rail industry has expanded rapidly since January 2011 as domestic crude production soared by 1.4 million barrels per day (MBD) over the same period. The growth of crude-by-rail followed pipeline bottlenecks in the Midwest that caused landlocked inland crudes to be discounted by upwards of $20 per barrel (Bbl) versus coastal destinations. That price discount made shipping oil by rail to the coast a viable proposition in the absence of new pipeline capacity. Crude-rail terminals in the Bakken formation now load over 400 MBD for shipment to coastal markets.

Higher demand for transporting Bakken crude is also proving to be a lifesaver for rail companies, which have experienced a dramatic decline in coal shipment volumes. Demand for rail services from oil companies is so high, in fact, that many companies are being forced to wait up to nine months to lease rail cars.

According to the Association of American Railroads, the number of rail cars hauling crude oil and petroleum products reached close to 241,000 in the first six months of 2012 compared to 174,000 in the first half of 2011.

Burlington Northern Santa Fe (BNSF) has increased capacity in 2012 to enable the railroad to haul one million barrels per day out of the Williston Basin in North Dakota and Montana. This increased capacity will allow the energy industry to continue the record expansion of oil production in the Williston Basin and to ship the new production to markets throughout the U.S. It will also benefit shippers of other commodities, including agricultural products.

Justin Piper of BNSF Railways reported that their system has moved mostly crude oil through their system to date, with only a small percentage being OSP transported to the U.S. (0.65 percent). There was a 300 percent increase in crude transport in 2011-2012, with no accidental releases. In 2012, there were 16 non-accidental releases averaging 3 gallons per release related to shipper related issues.

In 2012, there were 3,632 shipments of light sweet crude to Washington and 1,557 to Oregon (per Alberta Oil Sands Workshop for Washington State Department of Ecology, the Regional Response Team 10 and the Pacific States/British Columbia Oil Spill Task Force). In 2012, BNSF achieved an accident rate of 1.88 per million train miles, a record for their system. Petroleum unit trains normally contain 80-100 tank cars; each car has a 28,000-gallon capacity. Cars are typically owned, maintained and inspected by the transporter and expected to be a 40-year asset. The rail companies conduct additional inspections when the cars become part of a train. All cars are built to U.S. standards as specified in 49CFR174.

The safety program employed by BNSF has four parts: 1) community training; 2) emergency preparedness; 3) accident prevention and; 4) emergency response. The community training involves either in-person or online training for local emergency responders. Annually 3-5,000 people are trained nationwide. The emergency preparedness program involves development of an overall plan with appendices that define local response plans and environment sensitivity areas. Geographical Response Plans for water response have been developed for specific important environmentally sensitive areas such as the Northwest, Mississippi River, and rail-specific locations like the Columbia River, Colorado River and Glacier National Park (Flathead River), for example.

The accident prevention program utilizes onboard sensors/wayside detectors to determine brake or wheel problems, and engineering systems to improve track systems. The emergency response program involves an incident response command that includes all-hazards responders, operations personnel and contractors in one unified team. The team has available GIS with identified sensitive features, preplaced equipment and responder locations to streamline response actions. Preplaced equipment for hazardous spills in the Northwest is located in Pasco, Seattle and Spokane Washington. (http://www.unh.edu/workshops/oil sands Washington/Oil Sands Products Workshop Report)

Washington's oil refineries -- two near Anacortes, two in Ferndale and one in Tacoma -- have a combined processing capacity of about 654,000 barrels, of which about 43 percent is turned into gasoline.

The *Cherry Point Refinery*, seven miles south of Blaine, Wash., is the largest oil refinery in Washington with a processing capacity of 234,000 barrels per day. Historically, Cherry Point's crude oil has come from the Alaska North Slope (ANS). Though with decreasing North Slope production, ANS crude now comprises only approximately 50 percent of the Cherry Point Refinery's crude supply. Whether ANS crude or other foreign crudes, approximately 90 percent of the Cherry Point Refinery's crude supply is brought in by petroleum tankers via the Strait of Juan de Fuca and Rosario Strait and delivered directly to the refinery on the Strait of Georgia. The remainder of the crude comes from a pipeline connected to oil reserves in Western Canada. BP has applied for permits for a $60 million rail yard at its Cherry Point refinery north of Bellingham. The refinery is currently constructing a rail facility to import Bakken crude from North Dakota. The BP refinery would receive about 20,000 barrels a day by rail, less than a tenth of its 234,000 barrel-per-day capacity. This crude oil would replace some supply currently brought in by ship and serve to maintain production, not increase capacity.

The *Tesoro Anacortes Refinery*, 70 miles north of Seattle, is capable of processing 125,000 barrels per day. It receives feedstock via pipeline from Canada and ANS (Alaska North Slope oil) by tanker from Alaska. It also relies on a variety of crudes from foreign sources. Trains are also delivering Bakken crude oil from North Dakota and Montana to the Tesoro refinery, which recently completed a $55 million unit train unloading facility rail yard. The goal is to run six trains a week, shipping a total of 50,000 barrels of crude oil from the Bakken formation to the Anacortes refinery on each unit train. Tesoro expanded their receiving capacity to handle the new trains, and can unload two of these trains per day. Each train is about 100 cars long.

The *Shell Anacortes Refinery* has a capacity of 146,000 barrels per day. When the refinery first began operating, most of its crude oil came from Canada via pipeline. Although it continues to receive crude oil from Central and Western Canada, now most of the facility's feedstock arrives by tanker from oilfields on Alaska's North Slope. The Anacortes spur is an 18-20 mile long rail spur that comes off the main line at Burlington, Wash., and goes to the Shell and Tesoro refineries in Anacortes. Shell is exploring the potential to bring Bakken crude oil from North Dakota by rail to March Point for processing. This crude oil would replace some supply currently brought in by ship and serve to maintain production, not increase capacity. The project envisions one train per day in and out of the facility. Plans entail building a rail spur on Shell property with equipment to pump oil from rail cars into the facility at an estimated 50,000 barrels per day of crude oil. (Sightline Institute, The Northwest's Pipeline on Rails)

The *Phillips 66 Ferndale Refinery*, 20 miles south of the U.S.-Canada border, has a capacity of 107,000 barrels per day. The refinery processes primarily Alaska North Slope crude oil. It also receives Canadian crude oil via pipeline. Phillips 66 announced in June that it was buying as many as 2,000 railcars to transport shale oil [crude oil from the Bakken formation] to its refineries. It is set to build (completion Dec. 2014) a rail car receiving facility that will allow the plant to take 30,000 barrels per day.

The *U.S. Oil & Refining Co.* in Tacoma has a capacity of 42,000 barrels per day. The refinery is capable of handling weekly 100-car oil unit trains carrying Bakken crude oil from North Dakota at its new $8 million rail yard. Estimates are that the facility currently accepts 6,900 barrels of crude oil a day. (Sightline Institute, The Northwest's Pipeline on Rails)

Terminals, transloading facilities – Existing and proposed

Targa Resources Partners LP in Tacoma has agreed to provide rail unloading and barge loading services. The five-year agreement, which began in late 2012, allows advantaged U.S. or Canadian crude oil [Bakken or Oil Sands] to be unloaded from railcars at Targa's Tacoma terminal and transloaded onto barges for delivery to the Phillips 66 Ferndale Refinery. The facility also allows for delivery into the San Francisco, Calif., refinery, where crude imported from outside of North America could be replaced. The terminal is capable of receiving individual cars, but as volumes ramp up, it will transition to unit train capability. At full volume, the delivery capability is estimated to be approximately 30,000 BPD. (Sightline Institute, The Northwest's Pipeline on Rails)

Global Partners LP on the Columbia River in Clatskanie, Oregon, Port of St. Helens, announced that it has signed an agreement to acquire 100 percent of the membership interests in a West Coast crude oil and ethanol facility near Portland, Oregon, from Cascade Kelly Holdings LLC. The transaction includes a rail transloading facility serviced by the BNSF (Burlington Northern Santa Fe) Railway, 200,000 barrels of storage capacity, a deep water marine terminal, a 1,200-foot dock and the largest ethanol plant on the West Coast. The plant site is located on land leased under a long-term agreement from the Port of St. Helens. In November 2012, the facility began transloading unit trains of crude oil estimated to be 7,000 barrels per day. (Oregon Dept. of Environmental Quality)

The US Development Group, Hoquiam, Wash., is planning to spend $80 million constructing a facility at the Port of Grays Harbor's Terminal 3. Plans call for receiving 50,000 barrels of crude oil per day by rail, storing it on site in tanks, and transferring it to barge or vessel. (Sightline Institute, The Northwest's Pipeline on Rails). This proposal is still in discussion phase. Permitting has not begun yet on this potential project.

Westway's Grays Harbor Terminal, Hoquiam, Wash., is located at the Port of Grays Harbor where it currently operates a methanol handling facility. Westway is planning to spend $50 million building four additional storage tanks, each big enough to store 200,000 barrels of oil. The company hopes that the site will be operational by January 2014, but legal appeals of the permits will likely delay operations. (Sightline Institute, The Northwest's Pipeline on Rails)

Imperium Terminals (Hoquiam, WA) Imperium, a renewable fuels producer, is exploring a crude oil handling facility at the Port of Grays Harbor at the firm's existing site at Terminal 1. The company is proposing to spend $45 million constructing nine 80,000-gallon storage tanks and other facilities by 2014. Based on rail and vessel traffic estimates reported in news accounts, Sightline estimates that the site is likely to have a capacity of at least 75,000 barrels per day if it is completed. (Sightline Institute, The Northwest's Pipeline on Rails)

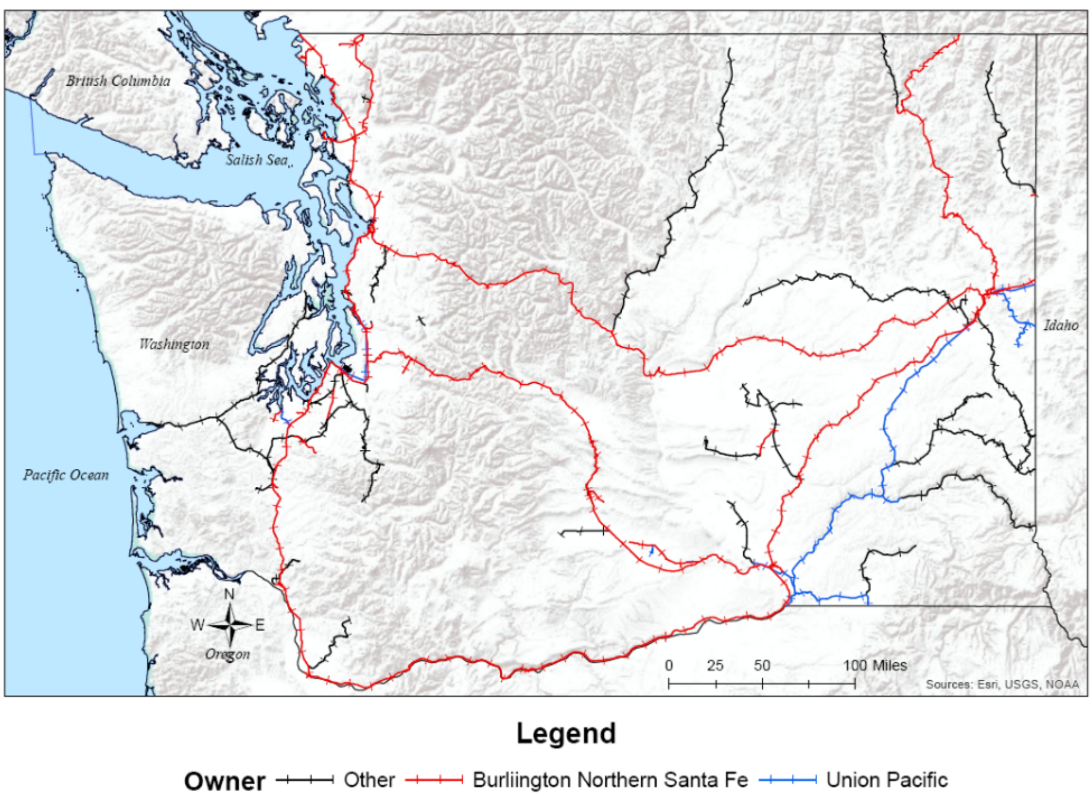
Tesoro / Savage, Vancouver, Wash., Tesoro's plan is to partner with Savage Companies to develop a $75 to $100 million rail complex at the Port of Vancouver. The facility is estimated to handle as much as 360,000 barrels per day. Company officials expect the site to be operational by 2014. (Sightline Institute, The Northwest's Pipeline on Rails)

Once the crude oil reaches these non-refining terminals, it may be loaded onto tank vessels (most likely barges) and transported to local refineries or exported out of the state to refineries). This will increase marine traffic and change the risk. We suggest monitoring the results of the Vessel Traffic Risk Assessment and help implement any mitigating measures that are proposed from that process.

Pipeline extension proposal

Proposed changes to Kinder Morgan crude oil pipeline on the Canadian side will allow the capacity on the U.S. side to increase from 170,000 barrels per day to an estimated 225,000 barrels per day.

Rail Lines by Owner



B. Definitions

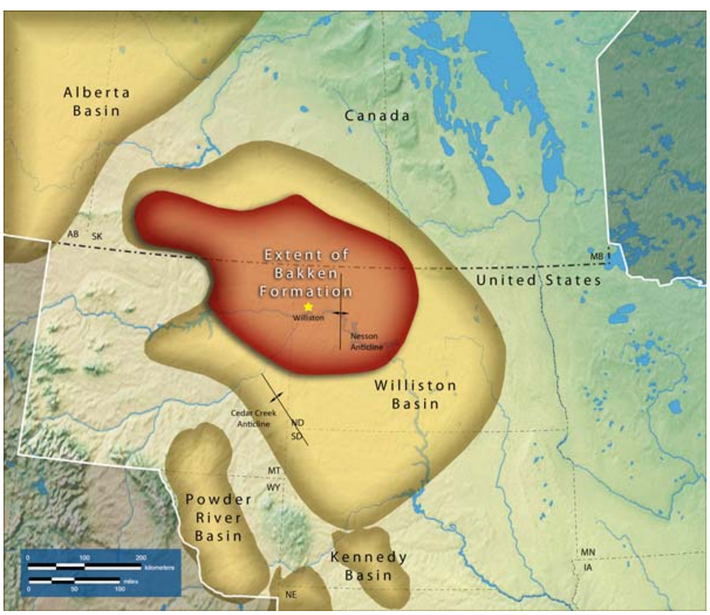
Oil Sands. Oil Sands, tar sands or, more technically, bituminous sands, are a type of unconventional petroleum deposit. The oil sands are loose sand or partially consolidated sandstone containing naturally occurring mixtures of sand, clay and water, saturated with a dense and extremely viscous form of petroleum technically referred to as bitumen (or colloquially “tar” due to its similar appearance, odor and color). Natural deposits are found in extremely large quantities in Canada, some 177 billion barrels or nearly 71 percent of global reserves.

Oil Sands Products. The density and viscosity characteristics of the raw bitumen material require blending for transport through pipeline or by rail tank car. To facilitate moving oil sands from production areas to ports or refineries, the bitumen is blended with diluents to reduce both density and viscosity and improve flow. The most commonly used diluent for mixing with bitumen is natural gas condensate. The blend of bitumen and diluent is often called *dilbit*. When the bitumen is mixed with synthetic crude oil (a partially refined bitumen product), the product is called *synbit*. Bitumen diluted with both a diluent and with synthetic crude oil is *dilsynbit*. As a group, the range of different blends based on bitumen as a base material is referred to *oil sands products*.

Diluents - In order to move bitumen efficiently through transmission pipelines, other petroleum products must be added to dilute it (diluents). These diluted bitumen products are called Oil Sands Products (OSP).

Bakken Crude Oil. Bakken crude oils originate from the Bakken Formation, occupying some 200,000 square miles of the subsurface of the Williston Basin underlying parts of Montana, North Dakota and Saskatchewan, could potentially contain recoverable reserves of up to 24 billion barrels of crude oil.

Map of Bakken Formation and Williston Basin



Source: Energy and Environment Research Center

> The rock formation consists of three components: lower shale, middle dolomite, and upper shale. The shale was deposited in relatively deep anoxic marine conditions, and the dolomite was deposited as a coastal carbonate bank during a time of shallower, well-oxygenated water. The middle dolomite is the principal oil reservoir, roughly two miles (3.2 km) below the surface. Both the upper and lower shale components are organic-rich marine shale. (Wikipedia article on Bakken Formation)

The Bakken Formation crude oils are also extracted from the shale deposits are characterized by very low permeability, averaging less than 5 percent porosity. In these deposits, the flow of oil from the rock to an extraction well is limited by the low permeability, fine-grained nature of the rock, which is the basis for the common term "tight oil." Recovery of oil trapped in these low-permeability rocks requires well stimulation techniques (physical or chemical actions performed on a well to improve the flow of oil or gas from the formation rock to the well bore).

The expanded use of new drilling, fracturing, and recovery techniques have resulted in dramatic increases in oil production. North Dakota's oil production recently reached 730,000 barrels per day. Bakken production has expanded so rapidly that companies have difficulties transporting oil to other parts of the country. Rail transport is allowing Bakken crude to be shipped to major terminals on the East and West coasts of the country where pipelines do not exist, or where pipeline capacity is limited.

C. Characteristics

1. Oil Sands Products

Oil Sands Origin. Alberta oil sands are believed to originate from a standard crude oil deposit that has undergone a significant degree of biodegradation. The lighter, shorter chain alkanes in the petroleum mixture have been degraded by naturally occurring microorganisms, leading to a partially weathered product with a predominance of large molecules. The biodegradation occurred at low temperatures (i.e., < 80° C), meaning pasteurization (sterilization) did not occur and microbial populations could continue to metabolize petroleum hydrocarbons.

The degree of biodegradation that may occur after a spill of oil sands products will be dependent on the extent to which the bitumen deposit was degraded prior to extraction and the inherent biodegradability of the diluent. Therefore, source bitumen that originally underwent a high degree of biodegradation would likely experience little further degradation after a release and weathering of the lighter diluent components. However, there are few experimental data available to fully evaluate the biodegradation potential oil sands products spilled into fresh or salt-water environments.

Bitumen Chemical Properties. *In situ* biodegradation of crude oil leads to a bitumen containing a lower proportion of paraffins (saturated hydrocarbons without rings) and naphthenes (saturated hydrocarbons with rings); and a higher proportion (>50 percent) of aromatics (hydrocarbons with one or more aromatic nuclei), which results in the increased viscosity and density characteristics of bitumen. Aromatics made up 37 percent of the total weight of Athabasca bitumen, followed by resins (25.7 percent), and by saturates and asphaltenes (both 17.3 percent). Gas chromatography has shown that Alberta bitumen is characterized by large, unresolved compounds (n-C_{10} to n-C_{40}) and a near absence of n-alkanes; C_{39} and larger molecules made up 56.96 percent of the weight of Athabasca bitumen.

Bitumen Physical Properties. Locating information on the physical properties of Alberta oil sands products can be challenging, as some of the specific physical and chemical properties data are considered to be proprietary business information. For this reason, it has been difficult for regulators and others in the scientific community to realistically model physical behavior in the environment.

Bitumen is generally characterized as denser than standard crude oil. The density of oil sands bitumen depends on the specific reservoir and temperature of the source material. Athabasca bitumen tends to be denser than freshwater, but less dense than saltwater, under standard conditions of 15.56°C. Between 25 and 40°C, Athabasca bitumen is less dense than water; Cold Lake Bitumen is denser than freshwater below ~40°C but less dense than saltwater.

As temperature increases, viscosity and density decrease; in some cases, this permits the raw bitumen to be transported in its native, albeit heated, state.

Bitumen can be orders of magnitude more viscous than conventional oils. At 25°C, the viscosity of conventional crude is ~13.7 cP (centipoise), while for bitumen it is >1,000,000 cP. Athabasca bitumen must approach 200°C, before its viscosity becomes similar to standard crude oil viscosity at ambient temperatures. Similarly, Cold Lake Bitumen must exceed 120°C before its viscosity is similar to standard crude viscosity at ambient temperature.

API (density) values for crude oils range from approximately <22-42, with refined products and condensates ranging higher. A summary of crude oil and other petroleum product densities is as follows:

- Gas Condensates – ≈ 42 to 55°API
- Light Crude Oils – ≈ 31 to 42°API - varies
- Medium Crude Oils – ≈ 22 to 31°API
- Heavy Crude Oils – ≈ <22°API
- Alberta Bitumen – ≈ 8°API prior to being mixed with diluent
- Water (≈10°API); Gasoline (≈63°API); Fuel Oil #2 (≈30-38°API)

Diluents

Diluents and Synthetic Crude. According to specifications established by Enbridge, the diluents used in the transport of oil sands products are light hydrocarbons with a typical density between 0.6-0.775 g/ml, a maximum sulfur weight by percent of 0.5 percent, and maximum viscosity of 2.0 cST (centistokes). Natural gas condensate, a liquid that under standard ambient conditions contains pentanes and heavier hydrocarbons produced from processing natural gas, is currently the most commonly used diluent. New pipelines have been proposed to supply diluent to Alberta and meet the growing demand for, but decreasing supply of, diluents in Canada.

Another method for upgrading bitumen for transport is to blend it with synthetic crude oil to make a product called "synbit." Synbit is a mixture of bitumen with synthetic crude—bitumen that has undergone upgrading through coking and hydrolysis to remove the larger molecules and decrease viscosity. Currently, this method is less expensive than mixing the bitumen with diluent. Projections suggest that the use of synthetic crude as a diluting agent will increase over the next decade, while the use of natural gas condensate will remain steady.

The characteristics of diluents vary across the range of products. Crude Quality Inc. provides an in-depth online list of the physical and chemical properties of several diluents.

Dilbit and Synbit Composition for Transport. The composition of dilbit varies between 25-30 percent diluent and 70-75 percent bitumen, depending on the viscosity of the bitumen and the density of the diluent. The ratio can be as high as 40 percent diluent for heavier bitumen. The diluent required for mixture can be decreased if the asphaltene fraction is removed from the parent bitumen. Because the diluent and bitumen are both hydrocarbon-based, the two are completely miscible.

For synbit, the mixture is typically 50 percent synthetic crude and 50 percent bitumen. Operating and spill-response experience reported by the Trans Mountain Pipeline is that dilbit and synbit behave as homogeneous products with fluid properties similar to other heavy crude oils.

Products transported in the Trans Mountain system, including dilbit and synbit crude oil, must meet the following *maximum* quality limits of the Canadian National Energy Board-approved Pipeline Tariff

- Reid vapor pressure: 103 kPa (kilopascal)
- Sand, dust, gums, sediment, water or other impurities (total in aggregate): 0.5 percent
- Receipt Point temperature: 38ºC
- Density: 940 kg/m³ (kilograms per cubic meter)
- Kinematic Viscosity: 350cSt (centistokes)
- Having any organic chlorides or other compounds with physical or

chemical characteristics that may render such Petroleum not readily transportable by the Carrier.

Corrosiveness of Oil Sands Products

Overview of Existing Research on Pipeline Corrosion. A recurring source of contention in discussions about the risks of transporting oil sands products via pipelines has centered on corrosion and the inherent corrosiveness of those products relative to traditional crude oil. Several research reports exist on the subject of oil sands products corrosiveness and although not entirely conclusive, the data suggest that oil sands products are generally *not* significantly more corrosive than other heavy crude oils being transported through pipelines. A brief overview of the findings includes the following points:

- Sulfur content of Alberta oil sands products ranges between 2-5 (weight percent). There are conflicting reports regarding how these sulfur levels compare to other heavy crude oils. That is, one report determined oil sands products to be generally comparable to other heavy crudes, with the exception of a few specific products; however, a U.S. Geological Survey study reported higher sulfur content as a fundamental difference between natural bitumen and conventional crude oils as a result of *in situ* biodegradation.
- TAN (total acid number) values of Alberta oil sands products ranged from .5-2.5 (mgKOH/g), which is comparable to many conventional heavy types of crude. Products with TAN values higher than 0.5 are generally considered "potentially corrosive," but in lab testing, the oil sands products were not found to be significantly different from comparable heavy crudes and not corrosive enough to be a concern to pipeline operators.
- Water content (expressed as BS&W, basic sediment and water) in oil sands products is comparable to other crudes, with the required maximum allowable threshold set by pipeline operators.
- Sediment content in dilbit crudes was found to be lower than or comparable to that of conventional crudes, with the exception of one dilsynbit blend that was found to have more than double the solids content of most other crudes. The data, however, only indicate the total amount of sediments, and do not provide information on the size distribution. It is unknown how the solids in the conventional crudes compared to those in dilbits.
- Sediment build-up in low or high spots in the pipeline interior can lead to corrosion.

In summary, research to date does not indicate that oil sands products are significantly more corrosive than other heavy crude oils. A National Academy of Sciences study currently underway and scheduled to be completed by the end of 2013 will analyze whether transportation of dilbit by transmission pipeline is subject to an increased likelihood of release compared with pipeline transportation of other crude oils. This study will be a review of existing literature and will not include any original research. PHMSA (Pipeline and Hazardous Materials Safety

Administration) data presented to the National Academy show that since 2002 there have been no releases of oil caused by internal corrosion from pipelines carrying dilbit. However, this does not imply that corrosion is not a concern: Combined internal and external corrosion account for 37 percent of non-small pipeline accidents for crude oil.

2. Bakken Crude Oil.

Bakken crude is considered a light (API Gravity from 36 to 44 degrees) –sweet (containing less than 0.42 percent sulfur) low viscosity crude oil with significant quantities of light, volatile hydrocarbons. Bakken crude is highly flammable and easily ignited at normal temperatures by heat, static discharges, sparks or flames (flash point less than -35°C and auto-ignition temperature of approximately 250 °C). Vapors may form explosive mixtures with air, and vapors may travel to source of ignition and flash back. Vapors may spread along ground and collect in confined areas such as sewers and tanks. The Upper Explosive Limit is estimated at 8 percent v/v): 8 (estimated). Lower Explosive Limit (4 percent v/v): 0.8 (estimated). If burned, carbon monoxide, sulfur oxides, nitrogen oxides and smoke particulates may be created.

The main properties and constituents of Bakken crude oil are shown and compared to synthetic crudes and diluted bitumen oils in the table below.

Summary of General Characteristics of Crude Oil That Would Be Transported by the Keystone XL Project (From: Keystone XL Project – Draft Supplemental Environmental Impact Statement – EPA, March 2013)

Characteristic	Synthetic Crude Oil[a]	Diluted Bitumen[b]	Bakken Shale Oil[c]
Density	na	na	827 kg/m^3
Specific gravity	0.84–0.86[g]	0.9–1.2	0.82–0.83
Viscosity	na	52 to 96 centistokes at 38°C	na
Flammability	na	Class B, Division 2: Flammable Liquids	Class B, Division 2: Flammable Liquids
Composition	Gas oils (petroleum), hydrodesulfurized 60% Naphtha (petroleum), hydrotreated heavy 10-30% Naphtha (petroleum), hydrotreated light, 3-7% Butane 1-5% Hydrogen sulfide (H_2S) 0.001-0.01% BTEX 1-1.5%	Bitumen 40-70% Light naphtha 15-40% Natural gas condensate 15-40% BTEX 1-1.5%	Light hydrocarbons <30% Pentanes 3-4% Hexanes 4-6% Heptanes 6-8% Octanes 6-8% Nonanes 4-6% Decanes 1-3% BTEX 1-3%
Flash point	68°F (20°C)	-0.4°F (-18°C)	na
Toxicity[d]	na	Class D, Division 2, Subdivision A: Very Toxic Material	na
Solubility in water[e]	Insoluble in cold water[f]	Insoluble[f]	Insoluble
Pour point	-5.8°F (-21°C)	-22°F (-30°C)	-25°F(-32°C)
Sulfur	0.25%	3.6%	0.17-0.20%
Other properties	Oxides of carbon, and nitrogen, aldehydes form upon combustion. Hazardous sulfur dioxide and related oxides of sulfur may be generated upon combustion.		

[a] Husky Energy 2011.
[b] Imperial Oil 2002.
[c] Crudemonitor 2012a. Five-year average was used for numbers.
[d] Table 3.13.5-12, Final Environmental Impact Statement (Final EIS).
[e] Table 3.13.5-12, Final EIS.
[f] Insoluble, but volatile organic compound and semivolatile organic compound constituents are soluble, (e.g., benzene, toluene, polycyclic aromatic hydrocarbons).
[g] Specific gravity for water = 1.0.
Notes: na = not available; kg/m^3 = kilograms per cubic meter; BTEX = benzene, toluene, ethylbenzene, and xylenes.

D. Response strategies

Oil Sands Products.

Although the physical characteristics of an oil sands product as blended for transport are expected to resemble those for typical crude oil products, uncertainties exist about the behavior of spilled and weathered product in the environment. Limited spill response experience reported by the Trans Mountain Pipeline and Western Marine Spill Response Corporation (WCMRC) during the 2007 Burnaby Harbor Spill is that the synbit spilled into the marine environment of Burrard Inlet behaved as a homogeneous product with fluid properties similar to other heavy crude oils. However, oil sands products may differ from crude oils in the rate at which lighter ends of the mixture volatilize, particularly in warm weather. As a result—and as demonstrated during the Enbridge Kalamazoo River Spill—spills of oil sands products may be potentially submerged or sinking, especially under high-flow and high-sedimentation conditions. As a result, responders should anticipate the potential for floating oil, and as time progresses, subsurface (neutrally buoyant and sinking) oil.

Procedures for responding to spills of Group IV and V oils have been described elsewhere and will not be repeated here. A few details of response actions and lessons learned from the limited case study histories for oil sands products (and one rail incident involving a heavy oil product) are reviewed below to provide insight into potential issues and challenges associated with these oils.

Case Studies. Two water-borne spills of oil sands products have recently occurred: the Kalamazoo River Spill in Marshall, Michigan, (dilbit) and the Burnaby Harbor Spill in Burnaby, British Columbia, (synthetic crude). Like all spills, these reflect unique circumstances and settings, limiting the ability to extrapolate universal lessons learned about oil sands products behavior and response methods. Due to the small number of case studies, this section will also examine the Wabamun Lake Spill, a railcar derailment that spilled Bunker C oil into a freshwater system in Alberta, Canada.

<u>Kalamazoo River Spill</u>

Spill Summary

Two types of dilbit oil were spilled during the Enbridge Pipeline spill into the Kalamazoo River system: Cold Lake and McKay River. Enbridge initially reported the size of the release to be 819,000 gal. This was later revised upward to 843,000 gal. Other estimates by the EPA have been substantially higher, up to 1.1 million gal. The reasons for the discrepancies in spilled-volume estimates are not clear and have not been resolved, but will factor into determination of Clean Water Act penalties.

The dilbit initially floated on the fresh water of Talmadge Creek and the Kalamazoo River. However, after mixing with sediments and the evaporation of the light hydrocarbons, some oil became dense enough to sink. As a result, there were periods during the response when the dilbit was simultaneously floating, submerged in the water column, and on the bottom of the river. Beyond the characteristics of the oil, water temperature, the presence of sediments, and the speed of the river affected oil.

Technologies Used in Recovery

An important factor impeding oil removal efforts during the Kalamazoo River Spill was the fast moving water of the river and Talmadge Creek. Recovering oil in fast-moving water is difficult, as oil tends to flow under containment booms and skimmer efficiency is greatly reduced, necessitating more rapid responses further downstream. In these situations, the Coast Guard recommends installing underflow dams, overflow dams, sorbent barriers, or a combination of these techniques.

Enbridge responders, with personnel from Terra Contracting and the Baker Corporation, used:

- *Oil booming and sorbent booming* at 33 oil-spill-containment and control points. At the most heavily boomed location, 176,124 feet of boom was deployed.
- One *Gravel-and-earth underflow dam* at the meeting of the contaminated marsh and Talmadge Creek. This site was chosen because it was accessible to heavy equipment. Responders did not have the traditional materials for adjustable underflow dams on-site and had to construct one out of surplus materials and, therefore, were late deploying the technology.
- Three *vacuum trucks* were used to recover oil at the underflow dam. Nine other vacuum tracks were deployed at other sites.
- *Oil skimmers* were also used to recover oil.
- On 25 acres, *dredging* was used to recover oil. This method was the most successful in terms of the amount of oil recovered.
- Responders considered plugging the steel culvert pipe under Division Drive with earth to contain the oil upstream, but the quick water flow prohibited attempting this method.

At the peak of deployment, 2,011 personnel engaged in oil spill recovery. As of summer 2013, the cleanup efforts were continuing. In October 2012, EPA directed Enbridge to dredge approximately 100 acres of the Kalamazoo River, as oil continued to accumulate in three areas. The main concern with the presence of this oil was that during a flood, the pools of oil could remobilize and contaminate parts of the river that had already been cleaned. EPA chose to move forward with dredging because it was deemed the most effective method during the original recovery efforts. Enbridge contested the EPA assessment, stating that further dredging would do more harm than good to the Kalamazoo River ecosystem. In March 2013, EPA ordered another round of dredging to remove submerged oil and oil-contaminated sediments upstream of the Ceresco Dam, in the Mill Ponds area, around Morrow Lake, and installation of sediment traps at two locations. The required dredging was to be completed by the end of 2013.

Lessons Learned Regarding Recovery Efforts
Three main issues were identified related to Enbridge's recovery efforts:

1. *Communication* –The spill occurred during the night and initial responders were not aware of the severity of the spill or the type of oil spilled, which led to impaired decision-making. Responders had no estimate of a volume release when the first round of containment methods was deployed.
2. *Lack of resources* – Originally, Enbridge responders did not have the resources to contain or control the flow of oil into the surrounding bodies of water (such as materials for underflow dams). Enbridge initially brought in contractors from Minnesota, a 10-hour drive from the spill site, which slowed recovery time. The EPA on-scene coordinator provided Enbridge with the contact information for local contractors to keep recovery efforts moving forward.
3. *Lack of Training* – During the initial response, Enbridge personnel placed the containment booms too far downstream to be effective, and also used booms that were incompatible with fast-moving water. This was related to both lack of

training, and also the lack of communication and knowledge regarding the severity of the spill.

Burnaby Harbor Spill

Spill Summary

On July 24, 2007, approximately 1,400 barrels (58,800 gal.) of synthetic crude leaked from the Westridge Transfer Line in Burnaby, British Columbia. After the oil was spilled, it flowed in Burnaby's storm sewer systems until it reached Burrard Inlet. In total, eleven houses were sprayed from the rupture, fifty properties were affected, 250 residents voluntarily left, and the Burrard Inlet's marine environment and 1,200 meters of shoreline were affected by the spill.

Five minutes after the rupture, the pipeline operator shut down the Westridge Pipeline, and the Westridge dock delivery valves were closed. However, the Burnaby Terminal is sited at a higher elevation than the rupture site, so gravity intensified the release of the oil. Twenty-four minutes after the rupture, the Burnaby Terminal and the Westridge Pipeline were fully isolated. Kinder Morgan established a unified command with the British Columbia Ministry of Environment and the National Energy Board (NEB) to coordinate the response. Nevertheless, the initial failure to fully shutdown the Westridge Pipeline was contrary to Kinder Morgan's standard shutdown procedures. Cleanup took months and cost roughly $15 million and resulted in the recovery of approximately 1,321 barrels of oil.

In 2011, three companies – two contracting companies and Trans Mountain Pipeline L.P. – pleaded guilty to violating the Environmental Management Act for introducing pollutants into the environment, and will each pay a $1,000 fine and donate $149,000 to the Habitat Conservation Trust Foundation. Trans Mountain Pipeline L.P. will be required to pay an additional $100,000 to fund training and education programs.

Technologies Used in Recovery

Kinder Morgan primarily relied on contractors to recover the oil (per Ministry of the Environment, 2007). The contractors used three distinct methods to recover the oil, based on the oil's location:

1. *Residential areas*. Peat moss was used successfully to absorb oil on land.
2. *Storm sewers*. Oil in the storm sewers was vacuumed up. Much of the oil was collected in the pump station.
3. *Burrard Inlet*. The responders were able to set up floating booms outside the storm sewer tunnels to collect oil that reached the Inlet. To treat the oil that had adhered to the shoreline, responders successfully used the chemical shoreline cleaner Corexit 9580.

Lessons Learned

The recovery effort during the Burnaby Harbor Spill was relatively successful. Because the synthetic crude traveled on a predictable path through the storm sewer system, responders were able to set up booms in a quick and efficient manner. We were not able to find any reports of the oil sinking or being submerged in the water column. However, extrapolating the oil behavior in this case to other potential synthetic crude spills is difficult because most of the oil was collected in the storm sewer systems and on land.

The primary issue in this case study was the lack of communication between city contractors and Kinder Morgan during the excavation process. As with the Kalamazoo Spill, failure to follow administrative procedures significantly increased the amount of oil spilled.

Wabamun Lake Spill

Spill Summary

Forty-three Canadian National Railway (CN) freight railcars derailed on August 3, 2005, adjacent to Lake Wabamun, just west of Edmonton, Alberta. The derailment resulted in 4,400 barrels of Bunker C oil and 554 barrels of pole-treating oil being spilled, with approximately 1,235 barrels[1] of the oil entering the temperate Lake Wabamun. The spill was caused by a faulty train track that had at least 13 undetected defects. Though Bunker C is not an oil sands product, it is a heavy oil and can have a density approaching that of water, and thus could be similar to undiluted bitumen. In this case, veteran spill responder Ron Goodman reported that the oil began to sink with limited amounts of weathering and sedimentation.

CN used an oil response contractor to recover the spilled oil. However, after the contractor's initial efforts, it became clear that the company was not sufficiently experienced in oil spills of this magnitude or of this type of oil. As a result, it was not able to contain the spill and CN eventually had to contract the cleanup to a more experienced response organization. The new response contractor surveyed oiling conditions using the Shoreline Cleanup and Assessment Technique (SCAT) and then moved to cleaning up individual shore segments. A number of reed beds were cut because the reeds became a continuing source of surface contamination. In total, approximately 1,076 barrels of oil was recovered and the response effort was completed in October 2005.

During the cleanup, there was strong public perception that the government failed to do its job, specifically, that the recovery efforts were more concerned with getting the track cleared and working again than with any ecological effects. This was compounded by the delay in beginning cleanup efforts due to lack of available equipment. As a result, the Alberta Ministry of the Environment established the Environmental Protection Commission in August 2005 after the spill; First Nations sued CN and were awarded $10 million. CN spent approximately $132 million in cleanup costs and paid $1.4 million in fines, and additionally made changes to its spill procedures and equipment requirements.

[1] The amount of oil that entered Lake Wabamun is debated and varies greatly depending on the source. This estimate is an average of the most commonly cited amounts.

Technologies Used in Recovery
Two main elements were taken into consideration during the Lake Wabamun Spill response: weather and the type of oil spilled. Both of these elements affected the behavior of the spilled oil, such as when the oil submerged and entered the water column or when the oil sank to the bottom (per Fingas, 2010). Responders used the following technologies:

- *Sorbent and containment booms* were the first technologies deployed at the site. Sorbent booms were ineffective in containing the Bunker C oil and there were not enough containment booms to stop the spread of oil due to high winds. It was necessary for additional equipment to be brought in from across Canada and the United States.
- *Dikes* were successfully built to stop the flow of oil into the lake. Once the ditches and dikes were completed, no further oil reached the lake.
- *Vacuum trucks* helped recover the oil.
- *Hand shoveling and skimmers* were relatively successful.
- *Sorbent pads* were used to probe the bottom of Lake Wabamun in order to detect oil that had settled on the bottom. The Bunker C oil had formed a skin and did not adhere to the pads, making this technology ineffective.
- *Video cameras for detection* were only successful in some shallow water situations due to the dispersed nature of the oil.
- *Nets of ten millimeters* were ineffective. Responders had to move toward very fine netting, which inhibited water flow. Ten-millimeter nets were tried due to the previous success with this size of net in collecting bitumen.
- Responders had very limited success in recovering oil once it reached the bottom.

It is important to note that it was not until four days after the derailment that responders realized that pole treating oil had been spilled, in addition to the Bunker C oil. The pole treating oil was mixed with other chemicals to be used as a wood preservative and potentially contained toluene, benzene and its derivatives, naphthalene and its derivatives, phenyls, and polycyclic aromatic compounds. As a result, possible workplace hazard associated with the chemical was neither recognized nor communicated until days later.

Lessons Learned
The spill response effort at Wabamun Lake was not efficient particularly due to management decisions. An emergency operations center under the unified command system (UC) was not set up. Under UC, response agencies collaborate on the response effort, with the main purpose to provide guidelines for multiple agencies to work together efficiently. This was the Transportation Safety Board of Canada's primary criticism of the CN response efforts. Other shortcomings observed during the response effort included:

- *Limited amounts of response equipment in close proximity to the spill.* This was problematic as it led to both negative public relations as citizens witnessed the oil spreading without an adequate response, as well as responders missing crucial time in containing the spill. Later, it was determined that some response equipment in the region was not made available because it was held in reserve in case of a concurrent environmental disaster.

- *The need for contingency planning.* CN implemented its Dangerous Goods Emergency Response Plan but failed to install a unified command. The lack of a central structure led to considerable confusion in the early stages of recovery as more responders arrived on scene and there was no organizational structure. Also, the contingency plan CN had in place was generic and had no specific guidelines for the Wabamun Lake area. The plans had not been tested recently and there had been little contact with response groups in the area.
- *Lack of information regarding the behavior of heavy oil when spilled.* In this case, the lack of information regarding the interaction of oil and fine sediments and how the changes in surface water temperature would influence submerged oil, tar ball formation, and the long-term fate of submerged oil in marine and fresh water ecosystems affected cleanup efforts.
- *Limited number of tested and effective oil detection technologies.* Response crews lacked appropriate technology for detecting oil once it reached the bottom of the lake.

Bakken Crude Oil Response Strategies.
Response to spills of Bakken Crude Oils are likely similar to response to other light, volatile rich crude oils. The effectiveness of standard spill response techniques applied to spills of Bakken Crude Oils needs to be synthesized for this report. Specific responder and public health factors to be taken into account during response are discussed in the following section.

E. Bakken Crude Oil Safety issues
(Cenovus Energy – MSDS and 2012 Emergency Response Guidebook)
Because of the presence of up to 30 percent (by volume) light volatiles in Bakken Crude, the potential for fire and explosion is the single largest risk to responder and public health. Accordingly, extreme caution should be exercised during the initial stages of response. The following general response guidelines are from the 2012 Emergency Response Guidebook prepared by the U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration and Transport Canada.

As an immediate precautionary measure, isolate spill or leak area for at least 50 meters (150 feet) in all directions. For large spills, consider initial downwind evacuation for at least 300 meters (1000 feet). If tank, rail car or tank truck is involved in a fire, ISOLATE for 800 meters (1/2 mile) in all directions; also, consider initial evacuation for 800 meters (1/2 mile) in all directions. For incidents with the potential to involve multiple rail cars or large tanks, this evacuation distance should be expanded accordingly. Keep unauthorized personnel away from the response. Stay upwind, keep out of low areas and ventilate closed spaces before entering unless atmospheric concentrations of contaminants have been evaluated.

<u>Fire Precautions:</u> **All these products have a very low flash point: Use of water spray when fighting fire may be inefficient.**

Small Fire
• Dry chemical, CO_2, water spray or regular foam.

Large Fire
• Water spray, fog or regular foam.
• Do not use straight streams.
• Move containers from fire area if possible without risk.

Fire involving Tanks or Car/Trailer Loads
• Fight fire from maximum distance or use unmanned hose holders or monitor nozzles.
• Cool containers with flooding quantities of water until well after fire is out.
• Withdraw immediately in case of rising sound from venting safety devices or discoloration of tank.
• ALWAYS stay away from tanks engulfed in fire.
• For massive fire, use unmanned hose holders or monitor nozzles; if this is impossible, withdraw from area and let fire burn.

<u>Personnel precautions:</u>
Only appropriately trained personnel should respond to uncontrolled releases. Avoid direct contact with material; use appropriate personal protective equipment. Inhalation or contact with material may irritate or burn skin and eyes. Fire may produce irritating, corrosive and/or toxic gases. Vapors may cause dizziness or suffocation. Wear positive pressure self-contained breathing apparatus (SCBA) until atmospheric conditions have been evaluated. Structural firefighters' protective clothing will only provide limited protection.

<u>Caution:</u> Hydrogen sulfide may accumulate in headspaces of tanks and other equipment, even when concentrations in the liquid product are low. Factors increasing this hazard potential include heating, agitation and contact of the liquid with acid or acid salts. Assess the exposure risk by gas monitoring. Overexposure to hydrogen sulfide may cause dizziness, headache, nausea and possibly unconsciousness and death.

<u>Environmental precautions:</u> Prevent material from entering soil, waterways, drains, sewers, or confined areas. Runoff from fire control or dilution water may cause pollution.

Small Spill or Leak
Eliminate all ignition sources (no smoking, flares, sparks or flames in immediate area). All equipment used when handling the product must be grounded. Do not touch or walk through spilled material. Stop leak if possible without risk. Prevent entry into waterways, sewers, basements or confined areas. A vapor suppressing foam may be used to reduce vapors. Absorb or cover product with dry earth, sand or

other non-combustible material and transfer to containers. Use clean non-sparking tools to collect absorbed material.

Large spill
Dike far ahead of liquid spill for later disposal.
Water spray may reduce vapor but may not prevent ignition in closed spaces.

First Aid
Move victim to fresh air.
Call 911 or emergency medical service.
Give artificial respiration if victim is not breathing.
Administer oxygen if breathing is difficult.
Remove and isolate contaminated clothing and shoes.
In case of contact with substance, immediately flush skin or eyes with running water for at least 20 minutes.
Wash skin with soap and water.
In case of burns, immediately cool affected skin for as long as possible with cold water.
Do not remove clothing if adhering to skin.
Keep victim warm and quiet.
Ensure that medical personnel are aware of the material(s) involved and take precautions to protect themselves.

II. CONCLUSIONS

Tar sand oils (and their derivatives) and Bakken Crude represent new and unique challenges to oil spill preparation and response community in the Northwest, owing to their unique characteristics, their relatively recent and dramatic increase in volumes shipped to new areas within the Northwest via new routes and transportation methods. Although standard oil spill response technologies, equipment, and experience in the Northwest is applicable to these new products, the locations and effectiveness of equipment currently staged in the Northwest needs to be further evaluated. Several key differences from the types of oils traditionally shipped in the Northwest (the potential for sinking oils and the potential for explosion of some products, for instance) highlight the need for continued evaluation of all aspects of response applied to these new products.

III. RECOMMENDATIONS

The Emerging Risks Task Force recommends that the Northwest Area Committee and its participants:

- Continue to watch developments in the push to develop new crude oil terminal projects and the corresponding increase in rail and vessel transport. This should include monitoring the Vessel Traffic Risk Assessment as one way to gage the increase in risk for the Northwest.

Continue to gather, analyze, and distribute information relative to response to spills of tar sand oils (and their derivatives) and Bakken Crude in the Northwest. In particular, the effectiveness of standard oil response equipment and strategies in addressing spills of Oil Sands Products and Bakken Crude oils needs to be evaluated, and the effects of spills on potentially impacted environments need to be available prior to the event of spills in order to streamline the response.

- Synthesize and incorporate information on response safety and appropriate measures to increase responder and public health and safety into appropriate chapters of the NW Area Contingency Plan, and make that information available for incorporation into local emergency management plans. Evaluate facility response plans to make sure appropriate safety information is available and consistent with the NW Area Contingency Plan.

  The Area Planning Committee will continue to support and monitor the outcome of the current risk studies, in particular the joint Vessel Traffic Risk Assessment, which could lead to a series of recommendations to manage the changing risks in the Northwest.

  Monitor studies that are occurring in Canada to support the various proposed projects to improve our understanding of the fate and effects, efficacy of dispersants and long-term toxicity of OSP.

  Study the distribution of response equipment between inland and marine areas to assess whether we are prepared for the changing inland risks.

IV. FINDINGS: COAL

A. Transportation picture

The Powder River Basin (PRB) supplies 40 percent of the coal in the United States. It is the primary source for coal shipped or planning to be shipped from West Coast coal ports. The PRB bridges both Wyoming and Montana. Mining companies such as Arch Coal and Peabody Coal operate there. Peabody Energy's PRB operations include coal seams up to 100-feet thick and include train-loading capabilities. Peabody Energy's operations in Wyoming produce more than 140 million tons of coal each year for customers.

There are two existing coal ports on the West Coast of Canada. The first, in Prince Rupert, British Columbia, is the home of Ridley Terminals Inc. The port is serviced by Canadian National (CN) Railway. Western Canadian mines export metallurgical and thermal coal. The facility can load at a rate of 9,000 tonnes per hour. The coal port has an annual shipping capacity of 12 million tonnes and storage capacity of 1.2 million tonnes. The port moors vessels of 325 meters LOA (length overall), 50-meters beam, 22-meters draft and 250,000 DWT (deadweight tonnage).

The second coal port, Roberts Bank Superport, a twin-terminal port facility in the greater Vancouver area, has an annual shipping capacity of 27.3 million tonnes. Its Westshore Terminal opened in 1970. The coal export terminal located at Roberts Bank, Delta, British Columbia, operates only 500 meters from the United States border. It is Canada's No. 1 export coal facility, surpassing the combined total coal exports of all other Canadian facilities. Westshore has also been the busiest single coal export terminal in all of North America, bringing in billions of dollars of export revenue for Canada and British Columbia. In recent years, Westshore has proved to be an increasingly popular choice on the West Coast for United States mines, particularly those in the Powder River Basin in Montana and Wyoming.

Proposed coal terminals on the U.S. West Coast
The Gateway Pacific Terminal (GPT) is located at Cherry Point - Ferndale, Washington. The proposal envisions an annual shipping capacity of 48 million tons.

The Millennium Bulk Terminals - Longview, Washington, has a proposal on the table to ship 44 million tons annually from the site of the former Reynolds Aluminum smelter in Cowlitz County.

The Port of Morrow in Boardman, Oregon, would have a proposed annual 3.5 - 8 million tons annual shipping capacity. The project would ship coal from the U.S. Intermountain region to Asian markets. Coal would be shipped by rail from Wyoming and Montana to the Port of Morrow. It would be transferred and loaded onto barges to be shipped down the Columbia River to Port of St. Helens' Port Westward Industrial Park. There, transloaders would transfer the coal onto covered oceangoing Panamax ships.

Railroad Routes:
<u>Sandpoint, Id. to Spokane, Wash.</u> (BNSF - 78.3 Miles) - The Montana Rail Link route from Mossmain would converge with BNSF direct coal from Shelby at Sandpoint, Id. and move on the BNSF line to Spokane, Wash. *All* (100 percent) BNSF export coal and oil to the Pacific Northwest moves over this 78.3-mile line segment. This line is commonly known as the "*Funnel*," and is the second-busiest rail corridor in Washington.

<u>Stevens Pass / Cascade Tunnel</u> - BNSF's Everett-Spokane line, which passes through the Cascade Tunnel at Stevens Pass, is the BNSF's major northern transcontinental route for double-stack intermodal container trains. It is heavily used, operated at about 70 percent of practical capacity in 2008. Empty oil tank cars and coal cars return eastward on this line.

Columbia River Gorge - The BNSF's Vancouver-Pasco line, which follows the Columbia River along the north side of the Columbia River Gorge, is used by double-stack intermodal container trains moving east and grain trains moving west to Pacific Northwest export grain terminals. The line is operating today at about 80 percent of practical capacity. This is the primary route for loaded oil and coal unit trains.

North-South I-5 Corridor - BNSF's line connecting Seattle with Portland, Ore., is the most heavily trafficked rail line in Washington State, conveying BNSF and UP trains (the latter via trackage rights) to and from the major Pacific Northwest ports. The corridor hosts an average of 58 freight trains each day. PRB to Pacific Northwest export coal tons will move over this route from Vancouver, Wash., to Longview and between Longview, and Seattle. Additionally, this is the route for Bakken crude oil transport to the Northwest.

Should these various rail-to-terminal projects be permitted and built, there will be an associated increase in vessel traffic to move the coal out of the state (or out of Canada through U.S. waters). It is not known but we can expect an associated increase in bunkering with the increase in vessel traffic. We suggest that we wait for the results of the VTRA before making conclusions on how this may change the risk picture for the Northwest.

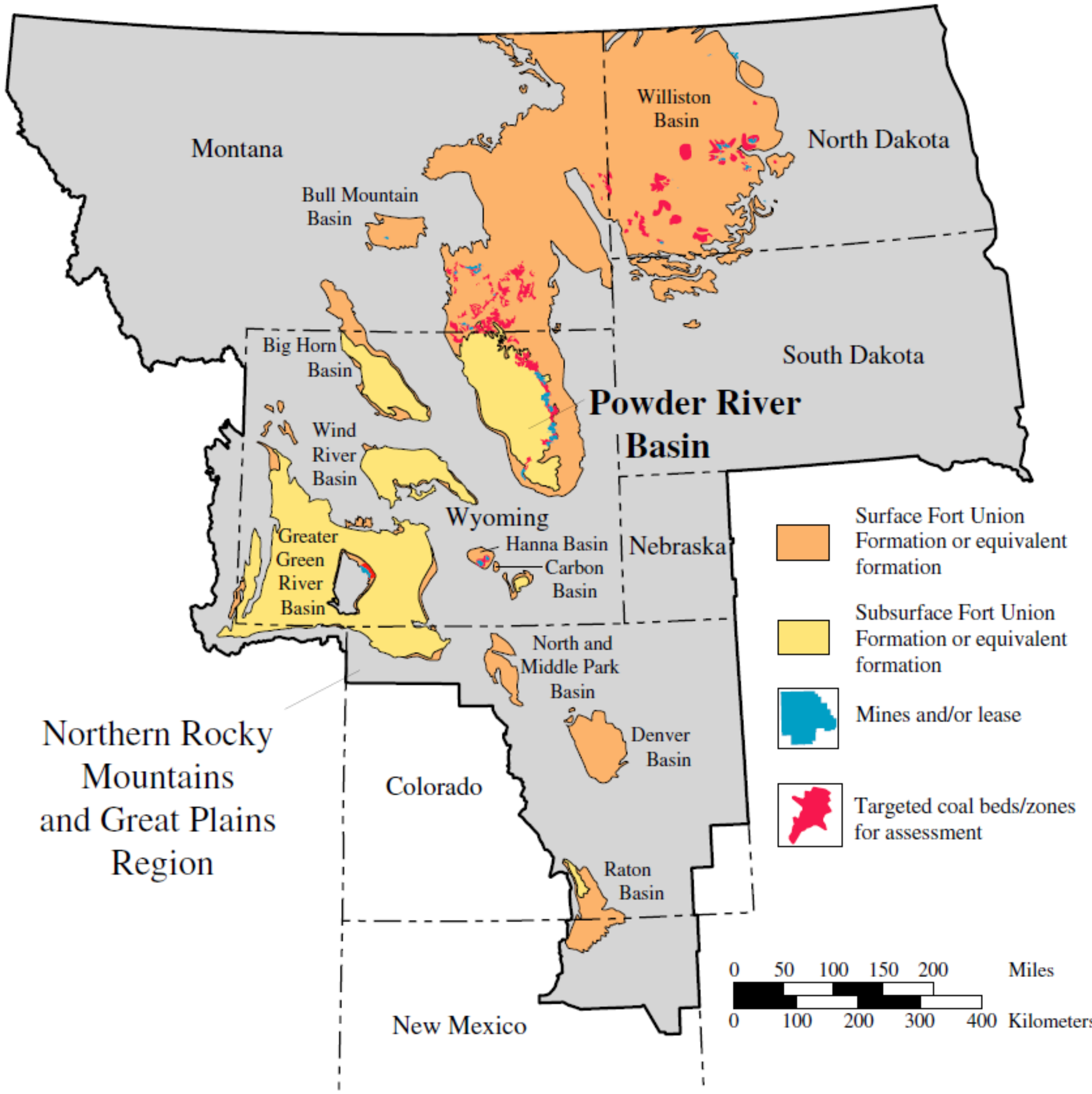
Should these various rail to terminal projects be permitted and built, there will be an associated increase in vessel traffic to move the coal out of the state (or out of Canada through U.S. waters). It is not certain but expectations are for an associated increase in bunkering with the increase in vessel traffic. We suggest waiting for the results of the Vessel Traffic Risk Assessment before forming conclusions as to how this may change the risk picture for the Northwest.
http://fragis.frasafety.net/GISFRASafety/.

B. Definition

Powder River Basin Coal. Coal mined from Powder River Basin (PRB) coal deposits found in southeast Montana and Northeast Wyoming (see map). PRB coal is classified as sub-bituminous, containing approximately 8,500 btu/lb, with low sulfur content relative to other coal sources. The table below compares characteristics and constituents of PRB Coal to Indiana Coal.

	Indiana coal	PRB coal
Moisture	10 -12%	~ 28%
Volatile matter	~ 40%	higher
Heating value	11,386 Btu/lb	Btu/lb 8,088
Ash content	9.4%	7.6%
AFT (flow, Reduction)	Need more data	?
Slag viscosity ~1400°C	Need more data	?
Char reactivity	Very few data Less reactive (higher T needed?)	More reactive because of more volatiles?
Sulfur	3.13%	0.72%
Chlorine	0.05%	0.01%

Source: M. Mastalerz, A. Drobniak, J. Rupp and N. Shaffer, "Assessment of the Quality of Indiana coal for Integrated Gasification Combined Cycle Performance (IGCC)," Indiana Geological Survey, Indiana University, June 2005



C. Characteristics

Coal is a heterogeneous material and varies widely in texture and content of water, carbon, organic compounds and mineral impurities. Among its constituents are such potential toxicants as polycyclic aromatic hydrocarbons (PAHs) and trace metals/metalloids. Due to coal's relatively low specific gravity compared to most sediment particles, transport by water movement may result in larger particles of coal being transported and deposited with smaller, denser particles of sands and gravels. Settling times and, therefore, transport distances will also be greater for a given particle size.

When present in marine environments in sufficient quantities, coal will have physical effects on organisms similar to those of other suspended or deposited sediments. These include abrasion, smothering, alteration of sediment texture and stability, reduced availability of light, and clogging of respiratory and feeding organs. Such effects are relatively well documented.

It is less clear whether organic compounds in coal can leach out into aqueous solution at concentrations that would cause concern from the perspective of potential biological effects. A fairly lengthy study sponsored by the USEPA (Carlson et al., 1979) used both Lake Superior water and purified water to create coal leachate solutions, but the concentrations of individual PAHs was less than 10-50 ng/L (parts per trillion). The predominant PAH types that solubilized were lower weight and alkylated PAHs, but the resulting equilibrium concentrations were equivalent to background levels in Lake Superior water. According to an environmental chemist with experience in distinguishing sources of PAHs in the marine environment, the tenacity with which PAHs are retained by coal can be explained by its physical structure:

> Coal often carries a petrogenic (oil-sourced) PAH signature that can be partially extracted on exposure to aggressive organic solvents like dichloromethane, but they are not bioavailable because they are sequestered within the mostly crystalline carbon matrix of coal. Consequently, the PAH signature contains abundant proportions of labile species like naphthalene that persist over geologic time scales in sediments
> (Jeffrey Short, JWS Consulting, LLC, pers. comm., 5 February 2013).

Toxic effects of contaminants in coal are much less evident, highly dependent on coal composition, and in many situations their bioavailability appears to be low. Bender et al. (1987) studied the uptake of hydrocarbons from coal in oysters and found virtually no increase in tissue burdens and no effect of even the highest exposure on shell growth. Chapman et al. (1996) studied the availability of coal dumped near Victoria (B.C.) harbor in 1891 and also reviewed the literature for effects of coal on aquatic organisms, and in both cases found little effect. Nevertheless, the presence of contaminants at high concentrations in some coal leachates and the demonstration of biological uptake of coal-derived contaminants in a small number of studies suggest that this may not always be the case, a situation that might be expected from coal's heterogeneous chemical composition; and recently, a noted NOAA toxicologist studying the biochemistry of oil hydrocarbons expressed concerns about the potential for biological effects from similar coal hydrocarbons. There are, however, surprisingly few studies in the marine environment focusing on toxic effects of contaminants of coal at organism-, population- or assemblage-levels. Campbell et al. (1997) found that juvenile Chinook salmon exposed to coal dust experienced elevated induction of CYP1a1, a gene encoding the xenobiotic metabolizing cytochrome P450 enzyme—but the implications of this to the health of the fish were not determined. The limited evidence indicating bioavailability of coal hydrocarbons under certain circumstances suggests that more detailed studies would be prudent, particularly with the Powder River product expected to be transported through the Pacific Northwest and under conditions of exposure relevant to our region.

Beyond the potential for uptake and effect of hydrocarbons in coal, another environmental concern may be the elevated levels of metals that are found in association with coal. While emissions from coal burning and coal fly ash have been well documented as sources of elevated trace metals into the air and soil, less information is available about the metal content of processed coal and the potential environmental implications from those metals. Struempler and Jolley (1979) measured trace metals in samples of Wyoming coal from the Fort Union and Hannah Formations (refer to figure above). For eleven Fort Union Formation coal samples, average concentrations (in parts per million) of metals were as follows:

Al = 6,700; Na = 780; K = 520; Mn = 41; Zn = 38; Cu = 21; Co = 4.1; Pb = 5.6; Cd = 0.43; Ag = 0.5; Tl = <0.5.

Bounds and Johannesson (2007) analyzed soil samples near the largest coal terminal in the northern hemisphere, located in Norfolk, VA. They found arsenic concentrations in soil samples and coal extracted from soil that ranged as high as 30.5 and 17.4 mg/kg (ppm), respectively. They concluded that risks from coal itself were likely minor, but environmental consequences of arsenic associated with the coal were not known.

As with the PAHs, it is not clear if or to what extent trace elements in coal are biologically available to potentially exposed organisms. As a result, the significance of concentrations of metals or other elements that occur with coal at naturally enriched levels is uncertain. Coal dust escapement and rainwater leachate from coal cars can be expected along rail corridors in the Northwest and at transfer terminals, and it is likely that concentrations of metals will be elevated in these areas (http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html).

A similar situation was documented in the latter part of the twentieth century along U.S highways and interstates, in which environmental concentrations of lead were found along the lengths of the roadways due to lead anti-knock additives in gasoline (since banned). However—whether the higher concentrations of metals that might result from coal transport by rail can be considered as environmental risks remains to be determined.

In the paper titled “Juvenile Salmonid Use of Habitats Altered by a Coal Port in the Fraser River Estuary, British Columbia,” C.D. Levings (Marine Pollution Bulletin, Volume, 16) describes alteration of habitat and diversion of Salmonid migration via an associated causeway due to impacts of coal terminal development.

The PAH content of coals is summarized in the table below. Powder River Basin coal would compare most directly to the Wyodak, USA, and possibly to other listed highly volatile, sub–bituminous entries.

Table 1 – Summary of total and 16 EPA polycyclic aromatic hydrocarbon concentrations in coals

	Total PAHs [mg/kg]	EPA-PAHs [mg/kg]	References
High volatile bituminous coal A, Elmsworth gasfield, 10-11-71-11W6, Canada	2429.1	152.1	
High volatile bituminous coal A, Elmsworth gasfield, 10-03-70-10W6, Canada	2412.3	136.6	
Medium volatile bituminous coal, Ruhr basin, Osterfeld, Germany	1037.2	153.3	
Medium volatile bituminous coal, Ruhr basin, Hugo, Germany	933.8	123.6	
Low volatile bituminous coal, Ruhr basin, Westerholt, Germany	1200.7	163.9	
Low volatile bituminous coal, Ruhr basin, Blumenthal, Germany	786.5	155.4	Willsch and Radke (1995)
Low volatile bituminous coal, Elmsworth gasfield, 06-19-68-13W6, Canada	546.4	98.6	
Low volatile bituminous coal, Ruhr basin, Haard, Germany	567.7	154.8	
High volatile bituminous coal, Wealden Basin, Nesselberg, Germany	656.2	43.1	
High volatile bituminous coal, Wealden Basin, Barsinghausen, Germany	554.4	56.7	Radke et al. (1990)
High volatile bituminous coal, Saar, Ensdorf, Germany	165.9	50.5	
Medium volatile bituminous coal, Germany	68.0	22.4	Pies et al. (2007)
Bituminous coal, Germany	127.6	28.7	
Lignite A, Northern Great Plains, Beulah, USA	8.5[a]	1.2	
Lignite A, Northern Great Plains, Pust, USA	6.5[a]	1.0	
Sub-bituminous coal C, Northern Great Plains, Smith-Roland, USA	12.0[a]	0.1	
Sub-bituminous coal C, Gulf Coast, Bottom, USA	14.0[a]	1.6	
Sub-bituminous coal B, Northern Great Plaines, Dietz, USA	14.0[a]	0.8	
Sub-bituminous coal B, Northern Great Plaines, Wyodak, USA	5.4[a]	0.3	
Sub-bituminous coal A, Rocky Mountains, Deadman, USA	12.0[a]	1.5	
High volatile bituminous coal C, Rocky Mountains, Blue, USA	77.0[a]	5.3	
High volatile bituminous coal B, Eastern Coal, Ohio #4A, USA	60.0[a]	8.2	
High volatile bituminous coal A, Rocky Mountains, Blind Canyon, USA	78.0[a]	4.4	
High volatile bituminous coal A, Eastern Coal, Pittsburgh, USA	76.0[a]	11.0	Stout and Emsbo-Mattingly (2008)
Medium volatile bituminous coal, Rocky Mountains, Coal Basin M, USA	29.0[a]	1.8	
Low volatile bituminous coal, Eastern Coal, Pocahontas #3, USA	20.0[a]	3.8	
Semianthracite, Eastern Coal, PA Semi-Anth. C, USA	5.9[a]	2.1	
Anthracite, Eastern Coal, Lykens Valley #2, USA	0.2[a]	<0.1	
High volatile bituminous coal, Blind Canyon, USA	78.3	–	Stout et al. (2002b)
High volatile bituminous coal C-1, USA	7.5	0.5	
High volatile bituminous coal C-2, USA	3.4	0.4	
High volatile bituminous coal C-3, USA	2.4	0.3	
High volatile bituminous coal B-1, USA	1.6	0.3	
High volatile bituminous coal B-2, USA	12.7	2.4	
High volatile bituminous coal A-1, USA	13.7	5.4	Zhao et al. (2000)
High volatile bituminous coal A-2, USA	27.6	6.4	
Low volatile bituminous coal, USA	1.2	0.3	
Anthracite, China	2.5	1.8	Chen et al. (2004)
Bituminous coal, Brazil	13.0	–	Püttmann (1988)

[a] Sum of 43 PAHS.

From: Native polycyclic aromatic hydrocarbons (PAH) in coals – A hardly recognized source of environmental contamination by C. Achten, and T. Hofmann, Science in the Total Environment, Elsevier B.V., 2008.

Summary table providing detailed analysis (n >150, depending on characteristic) of trace metals and other constituents in one coal zone of the Powder River Basin.

Table PQ-1. Summary data for coal in the Wyodak-Anderson coal zone in the Powder River Basin, Wyoming and Montana. Calculated from the unpublished U.S. Geological Survey coal quality database (USCHEM), February, 1992; Bragg and others (1994); and proprietary source(s)

Variable	Number of samples	Range Minimum	Range Maximum	Mean
Moisture [1]	300	14.50	42.30	27.66
Ash [1]	279	2.86	25.06	6.44
Total sulfur [1]	279	0.06	2.40	0.48
Calorific value [2]	277	3,740	9,950	8,220
lb SO_2 [3]	277	0.14	7.88	1.24
MMMFBtu [4]	277	4,580	10,560	8,820
Antimony [5]	144	0.01L	17	0.49
Arsenic [5]	158	0.20L	19	2.6
Beryllium [5]	151	0.078L	3.3	0.54
Cadmium [5]	151	0.007L	3.0	0.21
Chromium [5]	161	0.59L	50	6.1
Cobalt [5]	160	0.38L	27	1.9
Lead [5]	162	0.50L	17	3.0
Manganese [5]	161	0.18	210	26
Mercury [5]	162	0.006L	27	0.13
Nickel [5]	161	0.71L	35	4.6
Selenium [5]	151	0.08L	16	1.1
Uranium [5]	157	0.11L	12	1.3

[1] Values are in percent and on an as-received basis.
[2] Value is in British thermal units (Btu).
[3] Value is in pounds per million Btu and on an as-received basis.
[4] Value is in British thermal units on a moist, mineral-matter-free basis.
[5] Values are in parts per million (ppm) on a whole-coal and remnant moisture basis; "L" denotes less than value shown.

From: Coal Quality and Geochemistry, Powder River Basin, Wyoming and Montana by G.D. Stricker and M.S. Ellis in U.S. Geological Survey Professional Paper 1625-A: 1999 Resource Assessment of selected Tertiary coal beds and zones in the Northern Rocky Mountains and Great Plains region.

Regulatory Framework

Under U.S. Federal Regulations, coal is listed on the Toxic Substance Control Inventory. However, there is no CERCLA Reportable Quantity and it is not a listed waste under the Resource Conservation and Recovery Act (RCRA). As a solid waste, spilled coal would need to be characterized and a hazardous waste determination would need to be performed to determine whether RCRA is applicable. Coal is not considered an Extremely Hazardous Substance under SARA (Superfund Amendments and Reauthorization Act) TITLE III, Section 302.

The state environmental regulatory agencies consider spilled coal to be a solid waste, and potentially a hazardous waste depending on the presence of hazardous constituents. Available information on Powder River Basin coal does not indicate that hazardous constituents would be present in concentrations that would trigger designation as a hazardous waste if spilled, but that determination would need to be based on laboratory analyses of the source materials being transported, or through characterization of the waste itself.

The spillage of coal to land within the states would, at a minimum, trigger the need to characterize and clean up the wastes under state solid waste regulations. The spillage of coal into state waters, or into adjacent land area that could impact water quality would be a violation of water quality regulations and would necessitate immediate reporting to the appropriate state environmental agencies.

D. Response strategies

Appropriate response strategies for spills of coal will depend on the location of the spill, the environment the spill occurs in, and the media directly and indirectly impacted. All routes of transport or exposure, along with safety and occupational health concerns, need to be considered in site stabilization and cleanup efforts.

Response and cleanup of spilled coal would need to be coordinated with federal and state environmental agencies to make sure cleanup efforts do not further harm land or aquatic habitats, and to protect public health and the environment. Emergency authorizations and permits may be required to complete assessment and cleanup, and in some cases, the decision to delay or postpone these actions may be made to protect sensitive habitats. The NW Area Contingency Plan has resources to identify necessary permits and authorizations and the regulatory agencies administering them.

Collected wastes from the cleanup of spilled coal would need to be characterized and managed appropriately and disposed at an approved solid or hazardous waste facility, as indicated by the waste determination.

E. Safety issues

Coal handling and transport present unique challenges with respect to safety and protection of public and responder health. Risks of ignition, explosion, spontaneous combustion, the ability to create oxygen-poor environments, and the potential for dusts to create respiratory hazards must all be considered during routine material handling and spills alike. Although some elements of this topic are already covered in the Hazardous Materials and Marine Firefighting Sections of the Northwest Area Contingency Plan, the degree to which coal-specific safety elements are incorporated has not been evaluated by the task force. The integration of this information into local emergency management plans, or facility response plans also has not been evaluated.

From: Fire-protection guidelines for handling and storing PRB coal by Edward B. Douberly, Utility FPE Group, Inc.

Properties of typical firefighting agents

Agent	Properties
Water	Water can be effective at fighting PRB coal fires. However, water alone is not recommended. The surface tension of water does not allow it to penetrate deep below the coal's surface and reach the fire unless large quantities are injected. Large quantities of water inside a bunker or silo will ruin the coal inventory and may place additional loading on structural members.
Wetting agents	Wetting agents allow water to penetrate Class A material by reducing the surface tension of the water. They extinguish by cooling.
Foams	Foams contain a wetting agent that acts as the carrier of the foam. The primary function of foams is to blanket the fuel's surface, thereby reducing the oxygen supply. Foams are not very effective on coal fires due to the length of time it takes to smother a coal fire and the need to keep the foam blanket in place. Mechanical foams also tend to break down and dissipate before the fire is completely out. Deep-seated Class A fires cannot be effectively extinguished with foams. Foams that pass UL Fire Performance Criteria are Class B. Foams that do not pass the test are classified as Class A and do not meet any usage criteria other than the manufacturer's own recommendations.
Micelle-encapsulating agents	These agents, when used with water, are the extinguishing media of choice for PRB coal fires and for flammable liquids fires (Class A and B fires). These agents have the following three suppression mechanics: ▪ Micelle formation. On Class B fires, the agents encapsulate both the liquid and vapor phase molecules of the fuel and immediately render them nonflammable. ▪ Surface tension reduction. The agents reduce the surface tension of water from 72 dynes/cm^2 to less than 30 dynes/cm^2. This action provides up to a 1,000% increase in the wetted area, compared with using water alone. ▪ Free radical interruption. The agents interrupt the free radical chain reaction of the fire tetrahedron. For this application, they are governed by NFPA 18 and are listed for both Class A and Class B usage. Agents can be used effectively on coal fires at concentrations of 0.5% to 1.0%.
Other agents	Gases such as CO_2 and N_2 have been tried as fire-suppression agents but have not proven effective. Reasons include their poor cooling capacity and their general inability to maintain proper concentration levels in bunkers and silos. Accordingly, these agents require extended use —for hours or even days—depending on the quantity of the coal burning and the complexity of the fire. Independent testing has shown that the effectiveness of gases is a function of fuel geometry, the stage of the fire, the tightness of the enclosure, and the duration of application.

Source: Utility FPE Group Inc.

V. CONCLUSIONS

Although coal transport is not new to the Pacific Northwest, the dramatic increase in the amount of Powder River Basin coal transport presents new risks and challenges to emergency planning and response.

There is a general lack of information regarding the impacts of coal when spilled to the environment, and even limited information on the makeup and characteristics of coal originating from the Powder River Basin. The lack of information on constituents and characteristics of the PRB coals and their effects on the environment when spilled will complicate response and delay or impede characterization and cleanup efforts.

Though there is limited available information on the toxicity of coal constituents in freshwater and marine environments, the physical impacts of coal particles (especially dusts on land and suspended fine sediments in aqueous environments) represent risks to these environments that must be addressed if spilled, and will present challenges to the response and cleanup efforts.

The unique firefighting and safety issues surrounding coal are substantial and well documented in the literature but may be less known to local responders in areas where coal transportation has dramatically increased. The impacts of transportation and safety issues have likely not been incorporated into local emergency planning efforts.

VI. RECOMMENDATIONS

The Emerging Risks Task Force recommends that the Northwest Area Committee and its participants:

- Continue to watch developments in the push to develop new terminal projects and the corresponding increase in rail and vessel transport. This should include monitoring the Vessel Traffic Risk Assessment as one way to gage the increase in risk for the Northwest.

- Continue to gather, analyze, and distribute information relative to the response to spills of coal in the Northwest. In particular, detailed analysis of the constituents that make up Powder River Basin coal, and their effects on potentially impacted environments need to be available prior to the event of spills in order to streamline response.

- Support research to better understand the environmental consequences of Powder River Basin coal introduced into the aquatic and marine environments of the Northwest, specifically, whether contaminants associated with the coal (PAHs, metals, trace elements) are biologically available under conditions reasonably expected to be encountered in our region.

- Synthesize and incorporate information on response safety and appropriate measures to increase responder and public health and safety into appropriate chapters of the NW Area Contingency Plan, and make that information available for incorporation into local emergency management plans. Evaluate facility response plans to make sure appropriate safety information is available and consistent with the NW Area Contingency Plan.

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VII. FINDINGS: HEAVY FUEL OILS OR NONFLOATING OILS

A. Transportation picture

From 1991 to 1996, approximately 17 percent of the petroleum products transported over U.S. waters were heavy oils and heavy-oil products, such as residual fuel oils, coke, and asphalt. Approximately 44 percent was moved by barge and 56 percent by tanker. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

From 1991 to 1996, approximately 23 percent of the petroleum products spilled in U.S. waters were heavy oils. In only 20 percent of these spills did a significant portion of the spilled products sink or become suspended in the water column. Most of the time, spills of heavy oil remained on the surface. The average number of spills of more than 20 barrels of heavy oil and asphalt was 16 per year, with an average volume of 785 barrels per spill. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

In calendar year 2011, the five refineries in the [Pacific Northwest] region shipped 2.25 million barrels of <10 API gravity oil [heavy oil] in 41 vessel transits both by ship and barge. (Frank Holmes, WSPA, 2013 email) The five refineries: BP's Cherry Point Refinery (Ferndale, Wash.), Phillips 66 Refinery (Ferndale, Wash.), Tesoro Refinery (Anacortes, Wash.), Shell Refinery, (Anacortes, Wash.), and US Oil Refinery, (Tacoma, Wash.)

These over-the-water transports can trigger federal / state regulations which require Facilities, Vessels and Oil Spill Response Organizations (OSROs) http://www.uscg.mil/hq/nsfweb/nsf/nsfcc/ops/ResponseSupport/RRAB/osroclassifiedguidelines.asp to have additional equipment in their inventories to locate, contain and remove sunken [heavy] oil. See Vessel (33 CFR §155.1052 & Facility (33 CFR §154.1047) regulations. If a facility or vessel handles [heavy] Group V oil as a primary cargo, it must be called out clearly in their response plans and identify OSROs that have equipment to detect, contain and recover Group V oil. Within the Sector Puget Sound zone four, OSROs have identified themselves as having Group V capabilities. They are Marine Spill Response Corporation, National Response Corporation, Marine Pollution Control Corporation and Oil MOP Incorporated. Within the Sector Columbia River zone four, OSROs have identified themselves as having Group V capabilities. They are Marine Spill Response Corporation, National Response Corporation, Clean Harbors Environmental Services and Oil MOP Incorporated. https://cgrri.uscg.mil/UserReports/WebClassificationReport.aspx

OSROs self-certify that they have Group V [heavy oil] response capability by checking a box in the USCG National Strike Force (NSF) Response Resource Inventory (RRI) database. According to the National Strike Force Coordination Center, the CG RRI program has no programming in the system to validate these claims. Nor are these capabilities specifically targeted or confirmed during Port Area Visits by the USCG National Strike Force teams in the field conducting equipment verifications. In the lessons learned from the 2007 paper on the Tank Barge DBL, 152 author's note: "The current OSRO classification system and Vessel Response Plan review process do not validate the OSRO or owner/operators' ability to respond to a Group V oil spill. As a result, the nation's ability to respond to Group V remains unknown." (Elliott, et al., 2007) Self-certification without verification certainly calls for further discussion.

B. Definition

Group V Oils.

Oils in our Area of Responsibility (AOR) that represent the threat of sinking or are classified as Group V oils (Per 33 CFR 155.1020 - Definition Group V oil – One that has a specific gravity greater than 1.0.)

Specific gravity, as used in the regulatory definition of Group V oils, does not adequately characterize all oil types and weathering conditions that produce nonfloating oils. In addressing the issue of responses to Group V oil spills, defined by current regulations as oils with a specific gravity of greater than 1.0, the issue of concern is planning for and responding to oil spills in which most, or a significant quantity, of the spilled oil does not float. Some, therefore, may use the term "nonfloating oils" to describe the oils of concern. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

In Coast Guard District 13 / EPA Region 10, sinking oils are found in Group V Residual Fuel Oils (GPVRFO), known by the industry term "LAPIO" (Low API Oil), including Asphalt and Asphalt Products. Additional terms that can identify potentially sinking oils include No. 6 oil, Bunker C, heavy cycle gas oil, slurry oil or residual fractions, coal tar oil, carbon black feedstock and residual bottoms. There are small quantities of Residual Fuel Oil, just under a two-gallon yield, from each barrel of crude oil refined. (American Petroleum Institute (API))

New regulations in the state of Washington require a thorough description in oil spill plans concerning the types and characteristics of oils handled by the facility, vessel and pipeline companies. This includes both the API gravity and oil classification group. This will aid in the planning for responses within the Northwest community. The state has also adopted the federal standard for Group V oil equipment and requires that the assets be located locally.

C. Characteristics

"Heavy oil" is the term used by the response community to describe dense, viscous oils with the following general characteristics: low volatility (flash point higher than 65°C), very little loss by evaporation, and a viscous to semi-solid consistency (NOAA and API, 1995).

The term "nonfloating oil" is used to describe all oils that do not float on water, including oils that are denser than the receiving waters and either sink immediately or mix into the water column and move with the water as suspended oil; as well as the portion of oil that is initially buoyant but sinks after interacting with wind or waves. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Nonfloating oils move below the sea surface either because of their initial densities or because of changes in their densities as a result of weathering or interaction with sediments. These oils may be just below the water surface, suspended in the water column, or deposited on the seabed. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

The Nestucca Spill in December 1988 released 5,500 barrels of heavy marine fuel oil with an API gravity of 12.1 three kilometers off Grays Harbor, Wash. The spilled oil quickly formed tar balls that moved below the water surface (i.e., were overwashed by waves) and could not be tracked visually. Two weeks later, oil unexpectedly came ashore along the coast of Vancouver Island, Canada, 175 kilometers north of the release site, contaminating 150 kilometers of shoreline (NOAA, 1992).

D. Response strategies

There are a number of subcontractors connected to OSROs that provide niche expertise when it comes to detecting, containing and recovering sinking oils. They include but are not limited to local companies such as Manson Construction, Global Diving and Salvage, NW Underwater Construction, Fred Devine Diving and Salvage, Anchor Environmental and Hickey Marine. Nationally, major salvage companies such as T&T Marine Salvage have additional resources for detecting and recovering submerged oil.

Within the District 13 AOR, the expectation of the Co-chairs of the Area Committee and committee members is that Group V oil will be identified in the initial report of an oil spill to the National Response Center. Also, communication of the potential for sinking oil must again be brought to the attention of the Unified Command at the Initial UC Meeting. With knowledge that oil spilled is Group V, professional oil spill responders will identify specialized submerged oil equipment / personnel and get it on-scene. Unified Commanders must concern themselves with writing response objectives aimed at underwater detection, containment and recovery. The Operations Section will meet these objectives by developing detection strategies potentially using sonar, divers / cameras, ROV / camera, aircraft, photo bathymetry, diaper drops, dragnet, snare drops, and side-scan sonar. Containment strategies consist of using bubble curtains, water jets, surface-to-bottom nets/screens, silt curtain, and natural collection sites. Recovery strategies consist of using diver directed oil recovery operations, remotely operated vehicles, dredges, vacuum systems, integrated video mapping systems, nets, sorbents, bioremediation and pre-spill surveys. The difficultly in ramping up to detect and recover Group V oils in the water column or on the sea bottom is no small logistical / operational matter.

Within the District, there are a number of companies that are experienced with surface-supplied and saturation diving; but in general, above the minimum requirements of the CFRs, there is a not an extensive stockpile of submerged equipment resident in our region. Some of the more unique equipment is not resident and will have to be cascaded in from outside the region. Knowledge of and the decisions to mobilize specific equipment and personnel early from across the continent will be essential to waging an aggressive cleanup campaign. Specifically, detection equipment for sinking oil can be proprietary as it is an evolving technology.

The Incident Command System has the flexibility to expand to incorporate Sinking Oil Detection Groups, Sinking Oil Recovery Groups and Sinking Oil Divisions; however, no management system can be successful without awareness, planning and exercising beforehand.

Although spill modeling and supporting information systems are well developed, they are not commonly used in response to nonfloating-oil spills because of limited environmental data and observations of oil suspended in the water or deposited on the seabed. Oil-spill models and supporting information systems are routinely used in contingency planning and spill responses. Sophisticated, user-friendly interfaces have been developed to take advantage of the latest advances in computer hardware and software. The current generation of models can rapidly incorporate environmental data from a variety of sources and include integrated geographic information systems. The models can also assimilate data on the most recently observed location of spilled oil and have improved forecasts of oil movements. They are not routinely used, however, in response to nonfloating oil spills because of the lack of supporting data on three-dimensional currents and concentrations of suspended sediments. Field data, such as oil concentrations in the water column and on the seabed, are also not generally available to validate or update models. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Although a number of techniques and tools for tracking subsurface oil have been developed, most have not been used in response to actual oil spills. Many techniques are available for determining the location of oil both in the water column and on the seabed. These include visual observations, geophysical and acoustic methods, remote sensing, water-column and seabed sampling, *in situ* detectors, and nets and trawl sampling. The most direct and simplest methods, such as diver observations and direct sampling, are widely used, but they are labor intensive and slow. More sophisticated approaches, such as remote sensing, are limited to zones very near the sea surface because of technical constraints. Other advanced technologies, such as acoustic techniques, cannot differentiate between oil and water or between oiled sediments and underlying sediments. Many of the more sophisticated systems are prone to misuse and produce ambiguous data that are subject to misinterpretation. The performance of all but the simplest methods is undocumented either by field experiments or by use in spill responses. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Technologies are available for containing and recovering subsurface oil, but few are effective and most work only in very limited environmental conditions. Containment of oil suspended in the water column using silt curtains, pneumatic barriers, and nets and trawls is only effective in areas with very low currents and minimal wave activity. These conditions rarely exist at spill sites, particularly at sites in estuarine or coastal waters. The recovery of oil in the water column by trawls and nets is limited by the viscosity of the oil and net tow speeds. The containment of oil on the seabed is typically ineffective, except at natural collection points (e.g., depressions and areas of convergence). The collection of oil on the seabed by manual methods, in natural collection areas and along the shoreline after beaching, is effective but labor intensive and slow. Manual methods are also limited by the depths at which diver-based operations can be carried out safely. Dredging techniques have rarely been used because of limited recovery rates, the large volumes of water and sediment generated, and the problems of storing, treating, and discharging co-produced materials. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

The lack of knowledge and lack of experience, especially at the local level, in responding to spills of nonfloating oils is a significant barrier to effective response. The knowledge base and response capabilities for tracking, containing, and recovering nonfloating oils have not been adequately developed. Even at the national level, no system has been developed for sharing experiences or documenting the effectiveness and limitations of various options. With limited experience and a lack of proven, specialized systems, responders have found it difficult to adapt available equipment for responses to spills of nonfloating oils. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

E. Safety issues

Nonfloating oils behave differently and have different environmental fates and effects from floating oils. The resources at greatest risk from spills of floating oils are those that use the water surface and the shoreline. Floating-oil spills seldom have significant impacts on water-column and benthic resources. In contrast, nonfloating-oil spills pose a substantial threat to water-column and benthic resources, particularly where significant amounts of oil have accumulated on the seafloor. Nonfloating oils tend to weather slowly and thus can affect resources for long periods of time and at great distances from the release site. All told, the effects and behavior of nonfloating oil are poorly understood. (Spills of Nonfloating Oils: Risk and Response / National Research Council)

In general, a commercial diving operation inspection consists of three phases: (1) Personnel, (2) Operations, and (3) Equipment. The OSHA and Coast Guard regulations are similar in scope; however, additional requirements apply when conducting operations from vessels that require a

Coast Guard certificate of inspection. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

If the commercial diving contractor wishes to deviate from the USCG requirements, the contractor must submit a variance request in writing to Coast Guard Headquarters via the local Marine Safety Office. A copy of all approved variances must be available at the dive location or aboard the dive support vessel before commencing diving operations. OSHA does not permit deviations from their diving standards. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

When diving operations are conducted in contaminated water or in an area where there is a substantial threat of discharge of oil or hazardous materials, commercial divers must also comply with the OSHA training and operational standards for Hazardous Waste Operations and Emergency Response (HAZWOPER). Divers should provide proof of H AZWOPER training, and evidence that they have completed the annual refresher training, before commencing diving operations. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

Diving in contaminated water requires equipment that protects divers from pollutants. As a rule, if the pollutant is unknown, diving operations should not be permitted. With the exception of the requirement to comply with the HAZWOPER standards, to date, the U.S. Coast Guard, OSHA, and the International Maritime Organization have not published regulations that mandate specific equipment or training for diving in contaminated water. However, the National Research Council (NRC), U.S. Environmental Protection Agency (EPA), and the National Oceanic and Atmospheric Administration (NOAA) have published guidance and protocols. Additionally, the Association of Diving Contractors (ADC) has drafted industry standards for contaminated water diving that are now under review by the members of the association. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

The NRC's report on spills of nonfloating oils recommends operational limitations for diving in contaminated waters to depths of 20 meters, a minimum visibility of 0.5 to 1.0 meter, and low-water currents (NRC, 1999). However, existing OSHA and USCG regulations allow commercial divers to work in depths in excess of 60 meters, zero visibility, and heavy currents. Additionally, the ADC, EPA, and NOAA do not restrict commercial diving operations to depths that are more stringent than the depth requirements noted in the regulatory checklist, nor do they mandate visibility and current-speed standards.

A review of historical submerged oil recovery case studies shows that commercial divers have safely and successfully completed operations in conditions that exceed the NRC's proposed operational limitations. For example, during the *T/B Apex 3512* oil recovery from the bottom of the lower Mississippi in 1995, divers worked in depths that exceeded 20 meters, "zero visibility and a strong downriver current" (Weems, et al, 1997). Divers encountered similar conditions during the winter of 1995 submerged coal tar recovery in the Detroit River (Helland, et al, 1997).

It should be noted that according to the EPA, equipment problems in contaminated water are caused primarily by petroleum products (Traver, 1986). Divers exposed to petroleum constituents often experience equipment failure and deterioration. For example, Purser and Kunz provide a case study where a diver was exposed to elevated levels of benzene: "The benzene weakened the rubber straps on his helmet, and his neck, face and head were well exposed to the benzene mixture for a few seconds." The diver was later hospitalized due to his brief exposure (Purser and Kunz, 1985). (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

To prevent these types of accidents, safety officers should supplement their site-specific safety plan and on-site safety audits with a safety checklist for contaminated water diving. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

VIII. CONCLUSIONS

A. The tracking, containment, and recovery of spills of nonfloating oils pose challenging problems, principally because nonfloating oils suspended in the water column become mixed with large volumes of seawater and may interact with sediments in the water column or on the seabed. The ability to track, contain, and recover nonfloating oils is critically dependent on the physical and chemical properties of the oils and the water or the oils and the other materials dispersed in the water column or on the seabed. The differences in these characteristics are often quite small, and little technology is available for determining them. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

B. Although many methods are available for tracking nonfloating oils, the simplest and most reliable are labor intensive and cover only limited areas. More sophisticated methods have severe technical limitations, require specialized equipment and highly skilled operators, or cannot distinguish oil from water or other materials dispersed in the water column. Engineered systems for containing oil in the water column or on the seabed are few and only work in environments with low currents and minimal waves. Natural containment in seabed depressions or in the lee of topographical or man-made structures on the seabed is effective for containing oils, but these are not always present in the vicinity of the spill. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

C. The recovery of oil from the water column is very difficult because of the low concentration of dispersed oil; hence, recovery is rarely attempted. If oil collects on the seabed in natural containment areas, many options for effective recovery are available, although most of them are labor intensive and access to response equipment is a problem. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

D. The risks of potential harm to water-column and benthic resources from nonfloating oils have not been adequately addressed in the contingency plans for individual facilities or geographic areas. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

IX. RECOMMENDATIONS

The recommendations below are intended to improve the capability of the spill response community to respond to spills of nonfloating oils.

A. The Area Planning Committee must assess the risk of spills of nonfloating oils (i.e., oils that may be dispersed in the water column or ultimately sink to the seabed) to determine the resources at risk. In areas with significant environmental resources risk, the Area Planning Committee should develop response plans that include consultation and coordination protocols and should obtain pre-approvals and authorizations to facilitate responses to such spills. Stakeholder groups should be educated about the impact and methods available for tracking, containing, and recovering oil suspended in the water column or on the seabed. The Area Committee should include at least one scenario for responding to a nonfloating-oil spill in their training or drill programs. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

B. The Area Planning Committee must improve its knowledge base and training for responding to spills of nonfloating oils by including a scenario involving a spill of nonfloating oils in oil spill response drills, by establishing a knowledge base and scientific support teams to respond to these types of spills, and by disseminating this knowledge as part of ongoing training programs. The information would help area planners assess the requirements for responding to nonfloating-oil spills. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

C. The Area Planning Committee should support the development and implementation of an evaluation program for tracking oil in the water column and on the seabed, as well as containment and recovery techniques for use on the seabed. The findings of these evaluations should be documented and distributed to the environmental response community to improve response plans for spills of nonfloating oils. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

D. Tests of area contingency plans and industry response plans for responses to spills of nonfloating oils should be required parts of training and drill programs. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

E. Companies that transport sinking oils over the waters in D13 / Region 10 should expect Government-Initiated Unannounced Exercises with the specific objective of determining if they are prepared with the tools, strategies and tactics to carry out their companies' response plan with respect to sinking oils.

X. FINDINGS: LIQUID NATURAL GAS (LNG)

A. Transportation picture

On 1 August 2012, the North American Emission Control Area (ECA) as designated by the International Maritime Organization (IMO) went into effect. The ECA is intended to reduce air pollution and will impose enforceable limits on a variety of air emissions from vessels. In order to comply with these stricter emission standards, there has been a growing interest by the maritime industry in converting existing vessels and/or constructing new vessels to use LNG as fuel. The maritime industry is considering a variety of methods for supplying LNG to these LNG-fueled vessels. Such methods include, but are not limited to, LNG delivered from bunkering vessels, e.g., tank barges and small tankers), or via shore-based facilities, e.g., storage tanks in waterfront facilities, tank trucks, and rail tank cars.

Initially, few ports in the U.S. will have the infrastructure required for LNG vessels, but Seattle is on the leading edge of maritime usage and shore side distribution projects. Seattle can expect a potential increase in traffic as vessels shift to ports that have LNG refueling capability. There will be a variety of issues that this raises, including the fact that it could potentially reduce the oil outflow in the event of a casualty (e.g. LNG gets released and floats/evaporates). In addition, response plan holders should consider if new equipment is needed for an effective response. Industry comments indicate using LNG for fuel is one of the biggest revolutions in maritime transportation, not unlike going from sail to steam to fuel oil.

Proposed for Oregon. The state of Oregon is currently facing two proposals for LNG terminals, one in the Columbia River at Warrenton, and one in Coos Bay. The Warrenton proposal would be "bi-directional" with the ability to liquefy and export LNG as well as re-gasify and supply the interstate gas pipeline system during peak demands. The Coos Bay proposal is for liquefaction and export only. The pipeline for the Warrenton facility would tap into an existing gas pipeline near Woodland, Wash., requiring 80 miles of new pipeline. The pipeline supplying the Coos Bay proposal would tap into a hub near Malin, Ore., and will require 230 miles of new pipeline.

Oregon LNG's Proposal. Oregon LNG proposes to build an industrial complex on the Skipanon Peninsula, near the mouth of the Columbia River, primarily to liquefy and export LNG to Free-Trade-Agreement countries. The facility would also be equipped to re-gasify and feed gas into the interstate gas pipeline to level out peaks in demand. At peak production, 2 or 3 vessel visits each week could be expected. The proposal also includes 80 miles of new 36-inch pipeline from the facility, under the Columbia River near Deer Island, Ore., to join an existing pipeline on the I-5 corridor near Woodland, Wash.

Other information:
Dept. of Energy/Sandia National Laboratory conducted large-scale LNG pool fire experiments, which can be viewed at: https://web.ornl.gov/efcogWorkshop/Stirrup_persentation.pdf

USCG Headquarters has established a working group to provide guidance on safety, security and response concerns. The Dept. of Energy published a Notice of Intent to Prepare an Environmental Impact Statement for the Planned Magnolia (Louisiana) Liquefied Natural Gas Project in the Federal Register on June 25, 2013. In addition, IMO is also working to update LNG guidance.

B. Definition

Liquefied natural gas or LNG is natural gas (predominantly methane, CH4) that has been converted to liquid form for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. It is odorless, colorless, non-toxic and non-corrosive. Hazards include flammability after vaporization into a gaseous state, freezing and asphyxia. (Wikipedia)

C. Characteristics

LNG is made up of several hydrocarbon gases but mainly methane. This gas mixture is cooled until it condenses into a liquid form. The gas is extracted from the ground or produced as a by-product of oil or coal extraction, piped into liquefaction facilities, liquefied and piped onto LNG tankers. The LNG is then shipped overseas via tanker ship and delivered to import re-gasification terminals. At these import re-gasification terminals, the liquid is heated to return to its gaseous form and piped into pipelines to be delivered to the pipeline grid.

D. Response strategies / E. Safety issues

Controllable Emergency - This is an emergency in which the Terminal Operations Personnel can prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment, or initiating the Emergency Shutdown System. (Oregon LNG, Emergency Response Manual)

Uncontrollable Emergency - This is an emergency in which the Terminal Operations Personnel cannot prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment, or initiating the Emergency Shutdown System. An Uncontrollable Emergency involves situations that have the potential to result in exposure of personnel or property to natural gas in a liquid, cold vapor, or gaseous state or may result in fire or explosion. (Oregon LNG, Emergency Response Manual)

XI. CONCLUSIONS/RECOMMENDATIONS

Enormous U.S. deposits of natural gas buried in shale rock fields have flooded the domestic markets in the past few years. This gas surplus has changed the U.S. into an exporter of LNG versus an importer. The bottom has fallen out of the LNG import market. The single remaining importer is the Distrigas terminal in Boston Harbor in Everett, Massachusetts. It has one primary customer, the Mystic Power Station electric plant next door, under a long-term contract that does not expire until late next decade. (The Boston Globe, Jay Fitzgerald, January 23, 2013)

For the first time ever, the United States has the ability to become a major natural gas exporter, but that possibility comes with substantial economic and environmental risks. (LOOK BEFORE THE LNG LEAP, Craig Segall, Staff Attorney, Sierra Club Environmental Law Program)

XIII. FINDINGS: BIODIESEL

A. Transportation picture

The National Biodiesel Board lists 144 U.S. production plants in operation in for 2013. It must be noted that individuals unaware of federal and local regulations oftentimes try to blend their own biodiesel in their garages, shops or warehouses.

Biodiesel facilities in Washington State include the Gen-X Energy Group Inc., Moses Lake, which has a 6 million gallon per year nameplate capacity. General Biodiesel Seattle LLC has a 5 million gallon per year nameplate capacity. Imperium, Grays Harbor, located in Hoquiam, has a 100 million gallon per year nameplate capacity.

Biodiesel facilities in Oregon include Beaver Biodiesel LLC of Albany, which has a capacity of 0.94 million gallon per year nameplate capacity. SeQuential-Pacific Biodiesel, located in Salem, has a 17 million gallon per year nameplate capacity.

The Biodiesel facility in Idaho is Pleasant Valley Biofuels LLC, located in American Falls, and has a capacity of 5.5 million gallon per year nameplate capacity.

The Port of Tacoma has received proposals for a biodiesel/bulk liquids handling facility on the former Kaiser Aluminum smelter site on Blair Waterway. Port spokeswoman Tara Mattina said she could not discuss proposals because of ongoing negotiations.

Biodiesel infrastructure includes rail lines/railcars, barges/waterways, and tank trucks/highways. Pipelines are not often used. Infrastructure also includes terminals, storage tanks, blending facilities and transfer hubs.

Though no transportation routes were provided, an overview of biodiesel transport and marketing would look like this. Pure biodiesel product is transported to blending facilities by rail and truck, where it is mixed at the pipeline rack with petroleum diesel in the distribution terminal to provide B5-B20. These blends are transported to retailers by truck. The B100 product is also sold and used neat, as a more expensive "green" fuel.

B. Definition

Biodiesel is renewable diesel fuel substitute formulated exclusively for diesel engines. It is made from vegetable oil or animal fats derived from soybean, palm, algae, and/or recovered from commercial fryers then chemically processed with an alcohol such as methanol or ethanol. Methanol has been the most commonly used alcohol in the commercial production of biodiesel.

Biodiesel can be mixed with petroleum-based diesel fuel in any percentage, from 1 to 99, which is represented by a number following a B. For example, B5 is 5 percent biodiesel with 95 percent petroleum; B20 is 20 percent biodiesel with 80 percent petroleum, or B100 is 100 percent biodiesel, no petroleum.

Biodiesel is expected to play an increasingly important role in the world's energy profile. Production has increased dramatically over the last several years, from an estimated 112 million gallons in 2005, to nearly 1.1 billion gallons in 2012 (National Biodiesel Board, 2013).

C. Characteristics

An oil-methanol blend produces a biodiesel with the following physical characteristics:

- Not very miscible with water
- Completely miscible with diesel
- Less dense than water
- More viscous than water or diesel
- Gels at high temperatures
- Very low vapor pressure (Low fire risk)
- Mildly corrosive to metals, plastics and other synthetic materials (potentially important from a spill response perspective)

In an extensive set of comparisons between petroleum diesels and several biodiesels produced from different feedstock oils, the following observations were noted:

- Biodiesels are much more naturally dispersible in water than petroleum diesels
- Biodiesels are in fact mild surfactants and form a milky white emulsion in water
- Biodiesel-diesel blends as low as B10 to B20 can disperse diesel into the water column.
- Biodiesel will physically auto-degrade (with light, high temperatures, oxidizers)
- Biodiesel (B100) will biodegrade in eight days or less under optimal nutrient and oxygen conditions, in activated sludge

- Under more typical conditions, biodiesel will biodegrade 80-90 percent in 28 days (versus 50 percent in 28 days for petroleum diesels)

D. Response strategies

A major producer of soy-based biodiesel in California (von Wedel, 1999) suggests that while biodiesel would be expected to manifest a lower toxicity and impact than petroleum diesel if spilled in the marine environment, the soy product is still toxic and noted that in an October 1997 ruling under the Clean Water Act, as amended by the Oil Pollution Act of 1990, vegetable oils are considered "oil"—like petroleum—in contrast to France, where biodiesel is classified as food for transportation purposes.

Von Wedel points out that spilling biodiesel into the water would be as illegal as discharging petroleum fuels overboard. Waterfowl and other birds, mammals and fish that get coated with vegetable oils could die from hypothermia or illness, or fall victim to predators. Even though the biodiesel is relatively non-toxic and less viscous than vegetable oil, it can still have a serious impact on marine and aquatic organisms in the event of a big spill.

Hollebone also tested skimmer recovery efficiencies with biodiesels relative to petroleum diesels and determined that biodiesels were slightly more amenable to skimming, with those biodiesels derived from vegetable stock most readily recovered. Hollebone attributed these differences to viscosity differences in the product. For sorbent materials, the behavior of biodiesels was very similar to standard fuels of similar viscosity. However, tests were not conducted near the gel points for biodiesels, and there were indications that emulsification of the oils might result in functional problems for the skimmers.

Some (e.g., Fernández-Álvarez, 2007) have suggested the potential use of biodiesel as a standalone cleanup agent unto itself, citing its oleophilic character, relative low cost, "non-toxicity," and biodegradability. At least a few of Hollebone's observations could be construed to support this application, although the fact that biodiesel tends to act as a built-in dispersant for the petroleum portion of a diesel blend would likely not be viewed as a positive characteristic for a remedial agent.

A 2007 Seattle-area spill at a biodiesel production facility provides insight into other potential response issues related to facilities accidents. The spill occurred July 27 at the Seattle Biodiesel plant located on the east shore of the Duwamish River in an industrialized area of the city. An employee was pumping a processing-chemical mixture of vegetable oil, biodiesel, sodium hydroxide, methanol and glycerin from a large tank to a small portable tank. The transfer was left unattended, however, and the small tank overflowed and the mixture ran across a driveway into a small inlet along the Duwamish River. Between 391 and 620 gallons of the mixture reached the waterway. All but 23 gallons were recovered. While this cleanup was relatively successful, response personnel anecdotally related that some component or components of the spilled mixture had a corrosive effect on certain parts of recovery equipment such as skimmers. This could be attributable to the biodiesel itself (as noted by both Hollebone and von Wedel) or possibly to some of the chemicals used in production (such as sodium hydroxide, sulfuric acid, or methanol). In the event of a spill of biodiesel or at a biodiesel production facility, it will be prudent to understand the basic aspects of manufacturing and the chemical structure of the fuel that may affect response equipment. In areas where biodiesel spills represent a modest risk, it may be prudent to retrofit gear with corrosion-resistant parts.

The chemistry of biodiesels may present other unanticipated challenges during a spill incident, attributable to their non-petroleum derivation and chemistry. For example, response chemists using a standardized approach to forensically "fingerprinting" oil residues for legal or other reasons may find their protocols to be inadequate for a fuel derived from biological feedstock. Spikmans et al. (2011) and Fuller et al. (2013) discuss the modified analytical and forensic approaches that are necessary to source identify biodiesels and characterize weathering in the products.

The information presently available for biodiesels generally suggests a lower occupational exposure risk to response and cleanup workers, with the important exception noted by Hollebone that biodiesels may present an increased inhalation exposure risk. This should be considered during the determination of appropriate personal protection equipment, particularly during warmer conditions when increased volatility/evaporation could be expected in a spill.

The U.S. EPA has prepared and updated an overview of response for releases at biodiesel manufacturing facilities (Weston Solutions, 2008), focused on issues at production facilities. However, this guide contains excellent information and represents a good reference for spill response to biodiesel spills under any circumstances.

E. Safety issues

As a rule, biodiesels are less acutely toxic than their petroleum-based counterparts. Although oil in water dispersions of B5 and B20 blends were similarly toxic to rainbow trout as ultra low sulfur diesel, the neat (B100) biodiesels derived from canola, soy and tallow were much less so—or even nontoxic. With both Microtox® bacterial tests and the rainbow trout, the lowest toxicity results were obtained with the three B100 biodiesel formulations. Variably higher toxicity resulted from the blends and from petroleum diesel. Toxicity observations are as follows:

- Pure biodiesels are at least 5 times less acutely toxic than petroleum diesels
- Biodiesel blends up to B20 are similarly toxic to petroleum diesel
- The relationship between biodiesel content and toxicity is not linear
- No strong correlation between solubility and toxicity
- Large differences in organism sensitivity (with Microtox® > rainbow trout > water flea)
- Human lung cell assays: biodiesels more toxic than petroleum diesel; higher inhalation risk

- Biodiesels less toxic in rat tests than petroleum diesels, but wide variation among biodiesels

Ecological implications of biodiesel in the environment:

- Biodiesel biodegrades much more rapidly than conventional diesel
- Biodiesel in bulk can coat animals and inhibit oxygen transfer to aquatic species, similar to what would be expected for petroleum diesel
- Biodiesel is less toxic and has less of a solvent action than petroleum diesel
- Treatment of biodiesel-oiled wildlife would be similar to that for petroleum diesel exposures.
- Biodiesel has a high oxygen demand in water, which could result in fish kills.

Although biodiesel and biodiesel blends are less toxic than conventional diesel fuel, results from this study demonstrated that their risk to aquatic organisms is still quite substantial. Consequently, it will still have a serious impact on aquatic organisms if accidentally spilled or inadvertently discharged during transportation, storage, or use. Therefore, biodiesel and biodiesel blends should be handled with great care like any other fuel to avoid contamination to the watersheds, because their impact may have similar toxic effects as those of diesel spills

XIV. CONCLUSIONS / XV. RECOMMENDATIONS

Appropriate mitigation measures for release of biodiesel fuel include the following:

A. Proper air monitoring equipment

- Biodiesel fuel has a very low volatility at normal ambient temperatures and vapors are not typically an issue. However, vapors / mists may be generated when heated above 266 degrees Fahrenheit.

B. Proper spill containment

- Containment/response should follow typical oil containment procedures. Example: use oil-dry, petroleum-compatible absorbent socks, booms, etc.; the absorbent material used should be resistant to alcohol in the event methanol has further commingled with the biodiesel release. Disposal of biodiesel-contaminated soil or products can be considered non-hazardous provided methanol and/or hexane have not commingled with the release to meet the flammability characteristic for hazardous waste.

C. Expected fate of biodiesel

- Release in Soil
  - Biodegradation, with faster rates under aerobic conditions than anaerobic conditions, if it doesn't polymerize
- Release in Water
  - Insoluble in water. Degradation varies in aquatic environments
- Release in Air as result of spill/fire
  - Combustion produces carbon monoxide, carbon dioxide along with thick smoke
- Release to storm/sanitary sewers

  - May be high in free fatty acids and glycerol, and can have a high biochemical oxygen demand (BOD). These can disrupt wastewater treatment plant operations.

D. Overall health risks of biodiesel release

- Human Health Effects
  - Inhalation effects are negligible unless heated to produce vapors.
  - If biodiesel fuel were to be ingested, enzymes in the body called esterases would break the biodiesel fuel molecules into the component fatty acids and alcohol molecules. The alcohol is usually methanol and methanol is toxic. Thus, methanol toxicity could be a concern for ingestion of biodiesel fuel.
  - Neat biodiesel fuel is approximately 11 percent methanol by weight, so ingestion of 100 grams of biodiesel would release 11 grams, or 14 milliliters (mL) of methanol. For a 70-kilogram (kg) adult, the fatal dose of methanol ranges from 60 to 160 mL.

- Ecological Effects
  - Biodiesel may biodegrade more rapidly than conventional diesel. It depends.
  - When biodiesel is present in bulk in the environment, it can coat animals that come in contact with it and may reduce the ability of oxygen to reach aquatic systems. In this respect, its action is similar to petroleum diesel fuel.
  - The treatment of oiled birds and animals would be similar to the treatment provided when an oil spill occurs.
  - However, in water it has a high oxygen demand, which can lead to massive fish kills.

XVI. FINDINGS: SYNFUELS

A. Transportation picture

SYNFUELS transportation risks include; Vessel Collision, Sinking, Grounding, Fire**,** Allision, Breakaway**,** Rain/incidental water **and** Spillage of loose cargo.

B. Definition

Synthetic fuel or synfuel is generally a liquid fuel, less often a gaseous fuel, obtained from coal, natural gas, oil shale, biomass, or municipal waste. It may also refer to fuels derived from other solids such as plastics or waste rubber (such as used tires). The definition of synthetic fuel has been expanded from its traditional source materials of coal or natural gas to accommodate other naturally occurring or human-produced substances. In all cases, the end product is a combustible material intended for use in place of standard liquid petroleum fuels.

C. Characteristics

Both biofuels and synfuels have gained standing as alternatives to petroleum-based fuels in light of the inevitable scarcity of the latter as known reserves are tapped and drained. Although originally marketed as the means to grow or recycle our way to energy independence, biofuels and synfuels have more recently been shown to have external costs that make them less than ideal as absolute replacements for petroleum; however, they can contribute, sometimes substantially, to the energy portfolio feeding the needs of an industrialized society.

Synfuels are not a new development; in fact, some of the advances in petroleum distillation that paved the way for the rise of oil as an energy source occurred because early industrial chemists were seeking ways to convert abundant coal resources into liquid fuels. Oil sands were excavated and processed by the French as early as 1735 (Speight, 2007). Production of fuels from biomass, such as agricultural by-products like cellulose or lignin, is currently less developed, but is the subject of considerable research.

The primary incentive for synfuel development and use is the imbalance between supply and demand for petroleum liquids and natural gas (Ghassemi and Iyer, 1981). While recent discoveries of new oil and gas reserves and the improved efficiencies of petroleum and natural gas extraction methods have decreased the immediate demand for synthetic fuels, growing consumption rates for transportation fuels in particular—projected to increase 100 percent by 2050 (Bulushev and Ross, 2011)—dictate that synthetic fuels will remain an important component of world energy production well into the future. As biomass-derived synfuels are considered to be “carbon neutral” because the carbon dioxide produced in their combustion is “recycled” from plant-based carbon and not extracted from the ground, there are increasing numbers of mandates (e.g., U.S. Department of Defense, European Union) for production and use of biomass-based synfuels.

D. Response strategies

Synthetic fuel manufacturers are producing synfuel because associated tax incentives have allowed them to provide bulk coal consumers with a cheaper energy source. These consumers consist of power plants, coke plants, steel manufacturers, etc. Some of the synfuels being produced consist of approximately 99% coal and 1% oil emulsion. These oil-coal synfuels have produced sheens in the marine environment when accidentally released. The sheen sighting in turn prompts a Coast Guard response with possible pollution fines and costly mitigation efforts. There are no current regulatory requirements for the marine transportation of synfuel. The need for a synfuel marine-transportation risk assessment arose due to a lack of guidance from the Federal Government regarding enforcement of the Clean Water Act/Federal Water Pollution Control Act with this product. Because of the lack of guidance, industry was reporting sheens resulting from the secondary effects of the residual synfuel binder, which creates a sheen when the non-regulated product (coal) is accidentally released into the marine environment. (SYNFUEL A Western Rivers Marine Transportation Risk Assessment)

E. Safety issues

Ghassemi and Iyer (1981) evaluated the known differences in chemical, combustion, and health effects characteristics of coal- and shale-derived synfuel products and their petroleum analogs. The coal and shale synfuels were notable in their higher content of aromatic hydrocarbons and fuel-bound nitrogen and greater emissions of NOx (nitrogen oxides) during combustion. Fuel oils from coal liquefaction processes and crude shale oil were identified as highly hazardous because of established mutagenic, tumorigenic, and cytotoxic properties. These characteristics were associated with high boiling and tarry coal and petroleum materials caused by the presence of polycyclic aromatic hydrocarbons, hetero- and carbonyl-polycyclic compounds, aromatic amines, and inorganics such as arsenic in shale oil. That these synfuels are considered to be comparatively more toxic than their petroleum equivalents should be factored into assessments of potential human and wildlife exposures in the event of synfuel spills.

Synthetic fuels from biomass-based sources are considered to have similar or less severe environmental effects than coal-based synfuels (Office of Technology Assessment, 1982). However, from a broader perspective, large-scale production of biomass-based synfuels may result in more severe ecosystem impacts due to the extensive and potentially intensive nature of the cultivation practices for the resource base, e.g., corn or rapeseed. However, these would be reduced with a greater reliance on what is currently considered to be agricultural waste as biomass feedstock.

Khan et al. (2007) directly compared the toxicity of petroleum diesel and biomass-derived diesel on water flea (*Daphnia magna*) and rainbow trout (*Onchorhynchus mykiss*) and found that biodiesel was considerably less acutely toxic than its petroleum analog. However, they cautioned:

> Although biodiesel and biodiesel blends are less toxic than conventional diesel fuel, results from this study demonstrated that their risk to aquatic organisms is still quite substantial. Consequently, it will still have a serious impact on aquatic organisms if accidentally spilled or inadvertently discharged during transportation, storage, or use. Therefore, biodiesel and biodiesel blends should be handled with great care like any other fuel to avoid contamination to the watersheds, because their impact may have similar toxic effects as those of diesel spills.

XVII. CONCLUSIONS / XVIII. RECOMMENDATIONS

While the bulk of the “emerging risk” attention in the Northwest has been focused on the increased transport of oil sands products, coal, and Bakken crude oil through the region, the response community should at least remain aware that at some point in the future, synfuels may become a more significant part of the environmental risk equation. A challenge in generalizing a discussion of risk from synfuels is that the definition of the term has expanded to include source materials of widely differing origins and products with different chemical characteristics.

In every response, the basic question of “what is the material that spilled?” is key to every aspect of how the response is structured. Because synthetic fuels are fundamentally different from petroleum analogs, the need to distinguish a synthetic product and to understand its chemical structure is an important piece of the initial response information. Knowing that a fuel is synthetic, and that it is derived from coal, shale, or biomass would be of great utility in predicting potential impact and in appropriately responding. It is beyond the scope of this limited review to detail regulatory requirements for labeling or documenting synthetic fuels, but it is worth noting that for spill response, more information is almost always better than less.

XIX. OVERALL EMERGING RISK PICTURE

The evaluation of risks associated with an increase in petroleum traffic, petroleum volume and emerging information on oil types conducted by the Emerging Risks Task Force identified that, overall, the risks are a function of the shifting transportation of petroleum products by rail to inland areas and an associated predicted decrease in marine transportation of petroleum within the NW Area. Conversely, this is complicated by other potential changes which could increase the number of cargo ships calling on ports in the Northwest, the number of tank ships carrying crude oil out from Canadian ports through U.S. waters, and the number of tank ships (most likely barges) moving various types of crude oil via rail terminals to refineries in Washington or California.

In October 2012, the Washington Puget Sound Partnership Oil Spill Work Group and Puget Sound Harbor Safety Committee formed a joint Vessel Traffic Risk Assessment Steering Committee, comprising about a dozen representatives drawn from several maritime industry sectors, the Makah Nation, Washington Association of Counties, the Department of Ecology and the U.S. Coast Guard. The purpose of this study was to assess the relative risk in Puget Sound for vessels as the oil-movement picture changes. The information from the study will be used to evaluate potential risk mitigation measures. Our Task Force suggests that the Area Committee monitor the progress of the study and use the information to update this report and help implement mitigating measures that emerge, as appropriate. In addition, various Washington State proposed crude-by-rail projects discussed in this report may have permit requirements for more localized risk studies to help determine the risk impacts of the projects. These studies should be monitored as well.

New Petroleum Products and Risks, or More of the Same?

While there is a perception that the petroleum products in question - and particularly Canadian Oil Sands Products (OSP) and Bakken crude oil - represent materials that are “new” to the response community in the NW Area, this turns out to be false. OSP have been transported to the four northern Puget Sound refineries through the Trans Mountain Pipeline system since 1980 with no spills or operational issues (per The Center for Spills in the Environment, 2013). Under the U.S. Coast Guard’s definition of oils as set forth in Title 33 Code of Federal Regulations, Volume 2, Part 155, the OSP of concern - dilbit crude, synbit crude and syndilbit crude - fall within the parameters of Group IV oils, similar in physical and chemical characteristics to many other heavy crude oils delivered to area refineries by tank vessel since the 1950s. While Bakken crude oil is a new crude oil on the world market and a new feed stock to area refineries, Bakken crude exhibits physical and chemical properties which classify it as a Group II oil under the USCG definition, making it analogous from a response standpoint to many other Light Crude Oils, Diesel Fuel, Jet Fuel and Kerosene. Similar light crude oils have been utilized by area refineries throughout their histories as driven by product specification requirements and crude market prices. Moreover, Jet Fuel and Diesel Fuel are transported regionally by pipeline and in tank trucks daily. Both Group II and Group IV oils are very familiar to Oil Spill Removal Organizations (OSROs) and to Incident Management Teams (IMTs) in the NW Area and much of the region's response equipment is designed specifically to address spills of both of these classes of oils.

Oil Classification

Category	API Gravity	Examples
Group 1	>45	Gasoline, Condensate
Group 2	35 – 45	Kerosene, Jet Fuel, Diesel, No. 2 Fuel Oil
Group 3	17.5 – 35	Medium Crudes, IFO
Group 4	10 - 17.5	Heavy Crudes, Bunkers, No 6 Fuel Oil
Group 5	<10	Residual Oils, Asphalt

In their report on the 2013 Alberta Oil Sands Workshop, the Center for Spills in the Environment noted, "There are many open questions that need to be answered in order to better predict or model how heavy oils or OSP react after a spill" (p. 12). The general lack of precision regarding the prediction or modeling of the fate and effects of all heavy oils once released into marine waters - including OSP - remains a risk. As to OSP, more work is needed to understand the variety of diluents that may vary the characteristics of the products delivered to Washington refineries. Ongoing effort to improve the ability to better predict the behavior of these products, and thus direct a broad range of response operations, is warranted.

One of the recommendations from the 2013 Alberta Oil Sands Workshop was to ensure that Northwest area responders have plans in place and are equipped with appropriate equipment to monitor the safety of communities and responders, in particular to monitor benzene levels associated with spills of Bakken oil.

Rerouting the Risk

While the "new" petroleum products being introduced to the NW Area themselves may not constitute a new risk, what is different are the routes by which these petroleum products are and will be transported and the volumes being transported via these routes. Proposed routes and modes of transportation of petroleum products moving through Idaho, Oregon and Washington are addressed in Section I. of this document. The refining capacity is fixed. The transborder pipeline capacity is not maximized and is expected to increase in the foreseeable future. With anticipated increases in delivery of petroleum products by rail and pipeline, the NW Area can expect to experience a decrease in delivery of crude oil by tank vessel and an associated decrease in regional marine crude oil spill risk.

Risk assessments of the transportation of petroleum products have repeatedly shown that changes in transportation systems often shift risk from one location to another rather than reduce overall system risk. This tenet may hold true for the transportation of OSP and Bakken crude, particularly as it pertains to the transportation of these products by rail and the distribution of response resources - both equipment and personnel - relative to these inland transportation corridors.

In its most simple terms, risk is the product of consequence and probability, represented by the following equation:

$$R = L \times p \qquad (1)$$

Where: R = Risk
L = Loss or consequence, and
p = probability of occurrence

It can also be described in terms of frequency and severity. If we look at risk of an oil spill associated with increased petroleum transportation by rail, we find that the larger number of trains transporting oil, the higher the probability that one of these trains will experience an incident resulting in a loss of containment. Consequence or loss associated with any single incident has not necessarily increased, as the size of the trains transporting petroleum products has not changed appreciably from the Unit Train of $\pm$100 rail cars; however, BNSF Railways has reported a 300 percent increase in crude transport in 2011-2012 over previous years with the overwhelming majority of that volume being Bakken crude deliveries to Washington and Oregon. This significant increase in the number of trains transporting petroleum products translates into increased probability of occurrence and, therefore, increased incremental risk of a rail transportation-related spill along these inland rail corridors.

Additionally, this represents a change in severity, as we now must plan for spills of persistent oils in inland areas where previously the inland scenario was an oil type with a non-persistent characteristic.

Changes to the NWACP

The characteristics of OSP and Bakken crude fall within parameters that are currently addressed within the Northwest Area Contingency Plan (NWACP), though additional studies are needed to better understand the spill behavior/fate/effects/toxicity/ dispersant efficacy information. The focus on OSP has increased recognition that current fate and effects predictive modeling does not adequately address all aspects of the heavier Group IV oils and more work in this area is warranted.

Where the NWACP has traditionally focused on response to spills of oil to marine waters, recent changes and future trends in modes of crude oil transportation in the NW Area reflect a geographic shift to inland areas with a focus on rail transportation. This will result in a change in response strategy and response resource utilization and may warrant a review of the distribution of response resources. Federal On-Scene Coordinators will need to re-focus Preparedness and Response resources from traditional marine-based scenarios to a broader range of scenarios and work with Plan-holders to ensure that transfer of custody issues - and associated response expectations - are clearly articulated within Contingency Plans.

References:

The Center for Spills in the Environment, University of New Hampshire. 2013.

Alberta Oil Sands Workshop for Washington Department of Ecology, the Regional Response Team 10 and the Pacific States/British Columbia Oil Spill Task Force.

Recommendation Matrix

Recommendation	Owner	Tracking
III. Continue to support and monitor the outcome of the current risk studies, in particular the Vessel Traffic Risk Assessment, which could lead to a series of recommendations to manage the changing risks in the Northwest.	Area Planning Committee, Scott Knutson	Aug 2013: The VTRA Steering Committee expects a final report to be completed in Oct 2013.
III. Monitor studies that are occurring in Canada to support the various proposed projects to improve our understanding of the fate & effects, efficacy of dispersants and long-term toxicity of OSP.		
III. Study the distribution of response equipment between inland and marine areas to assess whether we are prepared for the changing inland risks.		
VI. Monitor the VTRA.		See Recommendation III
IX. Assess the risk of spills of nonfloating oils to determine the resources at risk.		
IX. Develop response plans that include consultation and coordination protocols and obtain pre-approvals and authorizations to facilitate responses to such spills.		
IX. Educate stakeholder groups about the impact and methods for tracking, containing, and recovering oil suspended in the water column or on the seabed.		
IX. Include at least one scenario for responding to a nonfloating oil spill in training or drill programs.		
IX. Establish scientific support teams to respond to nonfloating-oil spills.		
IX. Disseminate and share knowledge learned from nonfloating oil spills as part of ongoing training programs.		
IX. Develop an evaluation program for tracking oil in the water column and on the seabed, as well as		

containment and recovery techniques for use on the seabed. Document findings and distribute to the environmental response community to improve response plans for spills of nonfloating oils.		
IX. Require tests of area contingency plans and industry response plans for responses to spills of nonfloating oils as part of training and drill programs.		
IX. Conduct Government-Initiated Unannounced Exercises for companies that transport sinking oils over the waters in D13 / Region 10, with the specific objective of determining if they are prepared with the tools, strategies and tactics to carry out their companies' response plan with respect to sinking oils.		
XIV. Ensure proper air-monitoring equipment for biodiesel fuel response.		
XIV. Ensure proper spill containment for biodiesel fuel response. Containment/response should follow typical oil containment procedures.		
XVII. Remain aware that at some point in the future, synfuels may become a more significant part of the environmental risk equation.		

Underwater Noise Measurements at the WestShore Coal Terminal, Roberts Bank, British Columbia, September 2006

Prepared for

DRven Corporation
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December 2006

Underwater Noise Measurements at the WestShore Coal Terminal, Roberts Bank, British Columbia, September 2006

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December 27, 2006

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Introduction

Development of coal deposits on the west side of Cook Inlet in south-central Alaska would require construction of a marine terminal on the shore of Upper Cook Inlet. The west side of Upper Cook Inlet is relatively shallow near shore, preventing ships from docking along shore to receive cargo. Regular dredging of the nearshore area to increase the depth for ship passage would be costly and would permanently alter sea floor habitat potentially affecting fish, invertebrates, and marine mammals. A lower-impact solution is to construct and operate a pile-supported trestle and conveyor that would extend far enough out from shore to deliver coal to ships docked in deep water. Such a solution is proposed in the area known as Ladd, approximately 2.5 km (1.5 mi) north of the Village of Tyonek on the west side of Upper Cook Inlet, Alaska.

The proposed Ladd deepwater marine coal terminal would generate underwater noise that could potentially affect marine mammals and other marine wildlife near the terminal. The Ladd terminal would include a pile-supported trestle to carry conveyor systems that transport coal from the onshore coal yard to the vessel berths, approximately 3 km (2 miles) offshore, where water depths reach 20 m (65 feet). The primary sources of underwater noise will include the self-noise of large coal carrier vessels, the noise of coal being loaded into the holds of these vessels, and also noise from the conveyor and its drive systems that is conducted through the supporting piles into the water.

Little information concerning underwater noise generation and emission by marine terminals is available for the type of terminal planned for this project. To quantify the expected sound levels, JASCO Research Ltd carried out a sound measurement study at a similar marine coal terminal in a similar shallow-slope environment under a contract with DRven Corporation (through LGL Alaska Research Associates, Inc.). The noise measurements at this surrogate terminal are representative of noise levels that can be expected at the Ladd terminal. The study was performed at the WestShore terminal in Delta, British Columbia, Canada. The WestShore terminal is located at Roberts Bank in a delta environment, with water depths reaching 20 m at approximately 4.5 km (2.5 miles) from shore. The final 600 m (2000 feet) of the WestShore terminal consists of a pile-supported trestle that carries the coal conveyor system leading to the outer berth.

Underwater noise measurements were performed on 15 and 16 September, 2006 at the WestShore terminal using two bottom-moored autonomous sound recording systems, deployed for a 22-hour period. The recordings captured sounds produced by loading of a large coal carrier and the sounds produced by the pile-supported conveyor system. The noise measurements were used to compute 1/3-octave band source levels for the composite loading operation. These source levels were input to a noise model that computed sound level isopleths (presented as contour maps of sound levels) for the respective operations. These maps can be used to determine sound levels at any distance and direction from the terminal.

The results from this study are summarized in a Summary section, and a following Preliminary Recommendations section suggests methods that could be used to reduce underwater noise levels.

Study Location

The WestShore Coal terminal is located in Delta, British Columbia, Canada, approximately 25 km (16 miles) south of Vancouver. The main terminal is situated on an artificial island connected to the mainland by a 4 km constructed causeway with roadway and railway access (Figure 1). The island accommodates both the WestShore marine coal terminal and the Deltaport container shipping terminal. The WestShore terminal occupies the outer (southwest) section of the island, which can be identified by the darker area in Figure 1. Coal is delivered to the terminal by rail on a railway that is routed along the perimeter of the coal stockpile yard. Rail cars are dumped at a dumping station near the southwest corner of the yard and the coal is moved to the stockpiles using conveyor systems.

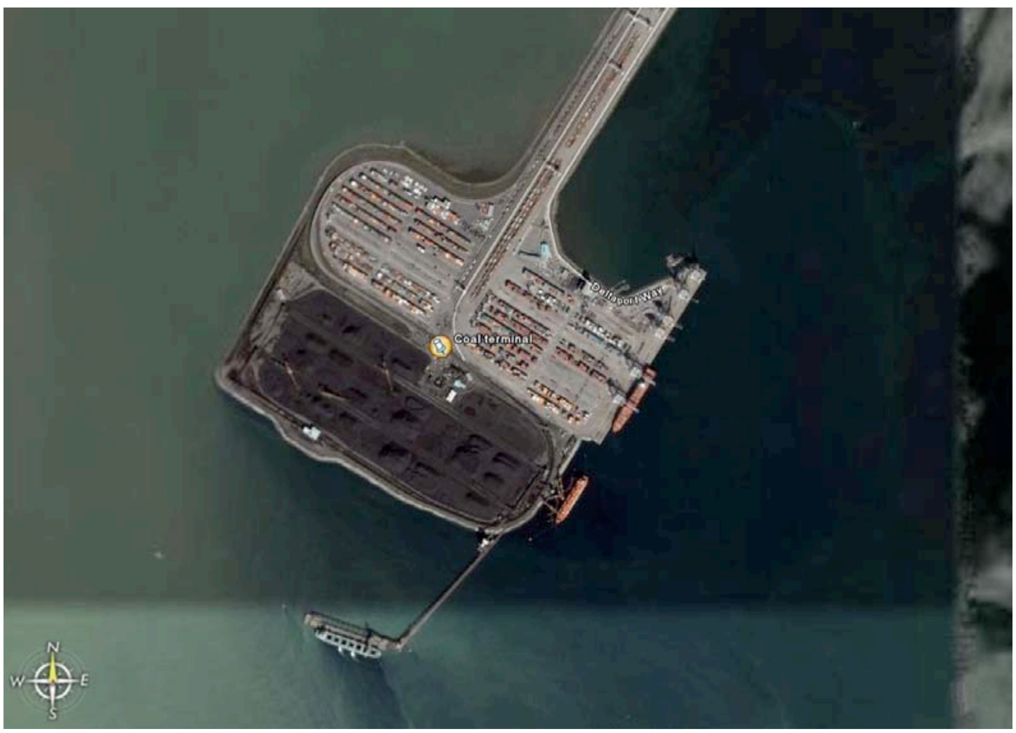

Figure 1: Aerial photograph of Westshore marine coal terminal in Delta, BC, Canada.

WestShore terminal has two main berths; the east berth is adjacent to the coal stockpile yard and the south berth is located at the end of a 600 m pile-supported trestle off the south corner of the yard. Coal is loaded from the stockpiles onto conveyor systems using wheel-diggers on large stacker-reclaimer equipment. The conveyors transport the coal to the berths where it is loaded through a hopper loader directly into the carrier holds.

The noise measurements made for the present study were made off the south berth. This berth is most closely representative of the proposed Ladd terminal berth in terms of water depth and its pile-supported conveyor belt system.

The WestShore terminal is adjacent to the British Columbia Ferry Corporation's Tsawwassen ferry terminal. That ferry terminal is in fact similar to the Roberts Bank terminal as it is situated on an artificial island with outer berths approximately 3 km (2 miles) from shore and it is connected to shore by a constructed causeway with highway. The proximity of this ferry terminal is important for this noise study because the large amount of ferry traffic causes substantial underwater noise.

Methods

Equipment

Two Ocean Bottom Hydrophone (OBH) systems were utilized for this project (Figure 2). The systems were anchored to the seafloor by expendable weights attached to the OBHs' acoustic releases. Each OBH system recorded 22 hours of single-channel continuous high-resolution digital acoustic data at 48 kHz sample rate with 24-bit samples. These systems incorporate calibrated Reson TC4032 hydrophones (nominal sensitivity -170 dB re V/μPa) that were factory-calibrated in October and November 2005 (standard recalibration schedule is 2 years). The calibration accuracy is formally ±2.5 dB from 10 Hz to 40 kHz, but these hydrophones have flattest response (and better stability) in the sub-5 kHz range, which was most relevant for this study.

The OBHs have an internal Sound Devices Model 722 hard-drive digital acoustic recorders housed in water-tight pressure canisters. The manufacturer's stated digital conversion accuracy of the recorders is ±0.2 dB and this was confirmed through laboratory calibration tests just prior to this field study. For recovery, an integral acoustic release was acoustically pinged from the surface to cause it to disengage the weight. The OBH's floats then floated the systems back to the surface for recovery and data download.

Figure 2: JASCO Ocean Bottom Hydrophone system

Field Study Location

The OBH systems were deployed in Georgia Strait off the south berth from a 23-foot workboat on 15 September at 13:00 and 13:17 PDT, at approximate locations 49° 0.542' N, 123° 10.042' W and 49° 0.417' N, 123° 10.135' W. The deployment locations were 400 m and 100 m respectively off the starboard (offshore side) of the carrier *Pierre LD* that was loading at the south berth (Figure 4). Water depths measured by the echosounder of the work boat were respectively 63 m and 43.5 m. The corresponding depths from a bathymetric map were 54 m and 37 m, but these were derived from a coarse dataset and are believed less accurate than the echosounder's measurements.

The OBH deployments were made directly at right angles to mid-ship of the carrier, and distances from the vessel were measured using a laser rangefinder. For deployment, the OBHs were balanced on the stern of the work boat as distance from the *Pierre LD* was monitored using a laser rangefinder. The OBHs were dropped off as the measured range was within 5m of the nominal 400 m and 100 m deployment distances. There may have been some additional drift of the OBHs as they descended to the seabed that could affect the final deployment positions by up to 10 m. The systems were left in place on the seabed through the remainder of 15 September and overnight. They were recovered in the morning of 16 September at 10:55 (OBH-A) and 11:00 (OBH-B). The data were copied to external hard drives and backed-up to data DVD.

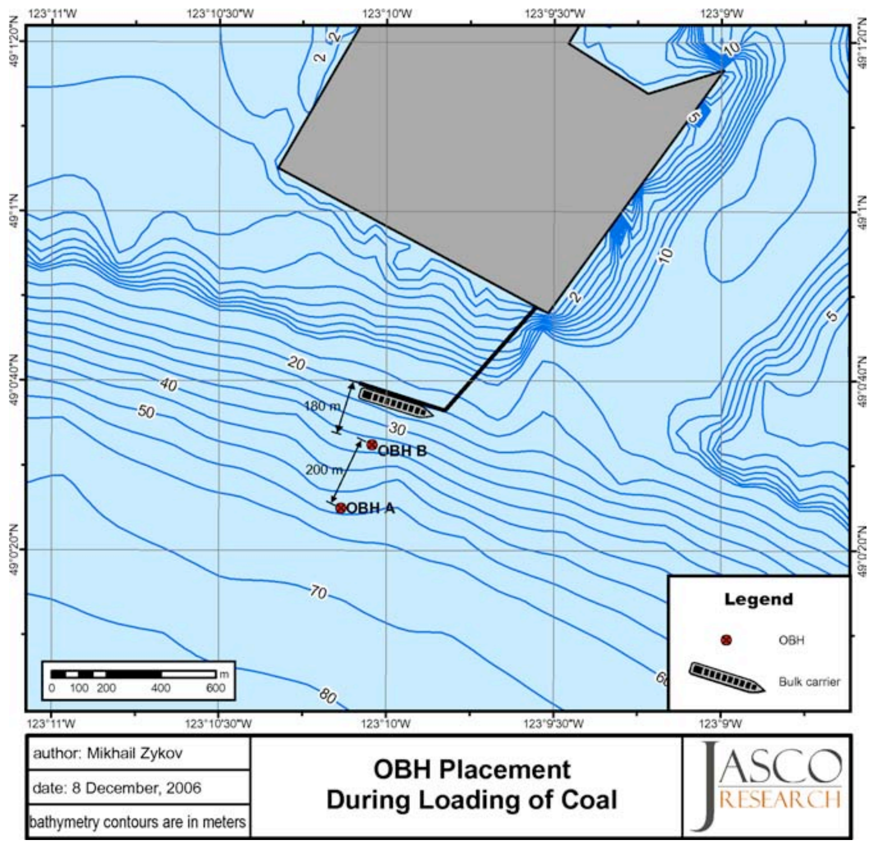

Figure 3: OBH deployment locations near the WestShore terminal, September 2006.

Figure 4: Photograph of Coal Carrier *Pierre LD* while it was loading at the south berth, September 15, 2006.

Data Analyses

The 24-bit acoustic recordings from the OBH systems provided high resolution capture of acoustic signals between 1 Hz and 24 kHz. These data were processed to obtain broadband sound levels, spectral levels, and several decade-band levels. The broadband frequency range reported here is 1 Hz to 24 kHz. The four decade frequency bands computed were: 1 Hz – 10 Hz, 10 Hz – 100 Hz, 100 Hz – 1 kHz, and 1 kHz – 24 kHz. We note the last band is not a decade band, but since most of its energy occurred below 10 kHz, and for brevity, we will refer to it as such. Spectral levels were calculated in 1 Hz frequency bins computed from 60 second fast Fourier transforms (FFTs) stepped in 30 second increments. Results are presented in data plots showing the spectrograms and decade band levels over the full 22-hour recording time period for the two OBH systems. The data plots contain two panels; the lower panel shows the spectrogram (spectral amplitude versus time and frequency), and the upper panel shows broadband and decade band sound levels versus time for the same period. The broadband levels were analyzed to compute percentile histograms.

A higher-resolution analysis was performed of two 10-minute time periods during which coal loading was occurring and noise from other sources (mainly ferry traffic) was low. The first 10-minute period includes the start of the loading into an empty hold and therefore contains loud sounds corresponding with coal striking the steel base of the hold. The second 10-minute period contains the sounds of loading after the hold was partially full (so the falling coal did not directly strike the bottom of the hold). This recording is more representative of the normal loading situation. Data from both 10-minute periods were processed using a 1 second FFT time windows computed in 0.5 second steps. The results from the first type (loading into empty hold) are plotted and discussed in the Results section. Data from the second period were processed to compute representative 1/3-octave band source levels for the normal loading operation. Those source levels were then used in a brief noise modeling study to compute sound levels at many locations surrounding the terminal. These results were used to generate sound level isopleths maps.

Results

General Noise Characteristics

Spectrograms and decade band levels for the two OBH systems are presented in Figure 5 and Figure 6. The large spikes in sound levels in all frequency bands above 10 Hz are due to passes by ferries and other vessel traffic. These vessel sounds are significant and dominate the noise field when present, but there are several time periods between passes and at night that contain primarily noise produced by coal terminal operations. Ferry traffic ended at 11 PM and did not restart until 6 AM, but two unknown vessel passes were observed in the recordings between at 00:45 and 02:00 on 16 September.

Conveyor System Noise

Broadband noise levels for sounds other than passing vessel traffic were dominated by acoustic energy in the 100 Hz to 1 kHz band. Noise levels in this band were 112-114 dB re μPa on OBH-A and 118-120 dB re μPa on OBH-B. The difference in levels on the two OBHs indicates that the origin of these sounds was near or at the loading location. This background underwater noise spectrum comprises a series of tonals that are clearly visible in all spectrogram plots, and they are attributed to the electric drive motors of the conveyor system and to self-noise from the *Pierre LD*. The specific conveyor drive motor responsible for most of this noise is at the base of the hopper located at the east end of the south berth, approximately 500 m and 300 m respectively from OBHs A and B. This hopper is at the far right side of the photograph in Figure 4. These measured levels correspond with an effective source level of approximately 174.5 dB re μPa at 1m. Airborne noise from this motor system was clearly audible from the workboat on the water at 1 km range, and in one instance as far away as 2 km.

Coal Carrier Self Noise

Underwater noise in the 10 Hz to 1 kHz band increased by almost 7 dB at 03:00 on 16 September to 121 dB re μPa on OBH-A and 126 dB re μPa on OBH-B. This noise is attributed to use of the *Pierre LD's* propulsion system to assist with maintaining position at the berth as wind speed reached 15 kt at 03:00. Weather information including wind speed and direction for the full recording time period is given in Appendix A. Wind speed increased gradually from near 5 kt at 20:00 on 15 September to 20 kt at 09:00 on 16 September. Wind direction remained fairly constant from the northeast, which was broadside of the vessel, and pushing it directly off the berth. The source level of this propulsion noise was 166-173 dB re μPa at 1m.

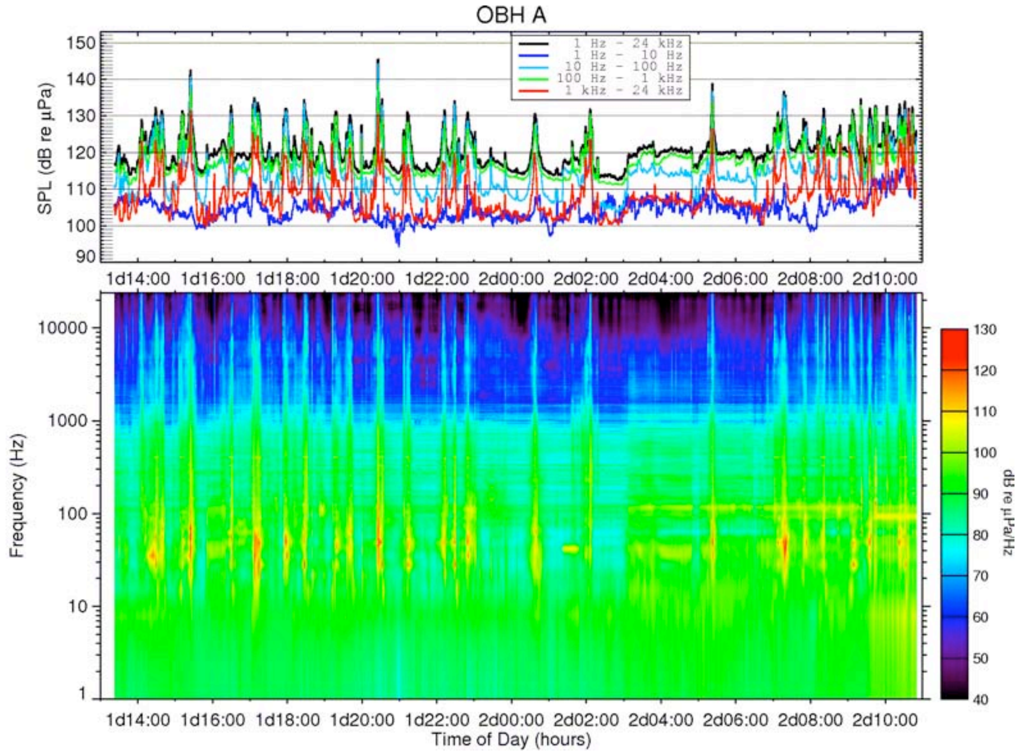

Figure 5: Spectrogram and band levels from OBH-A for a 22-hour monitoring period, September 15-16, 2006.

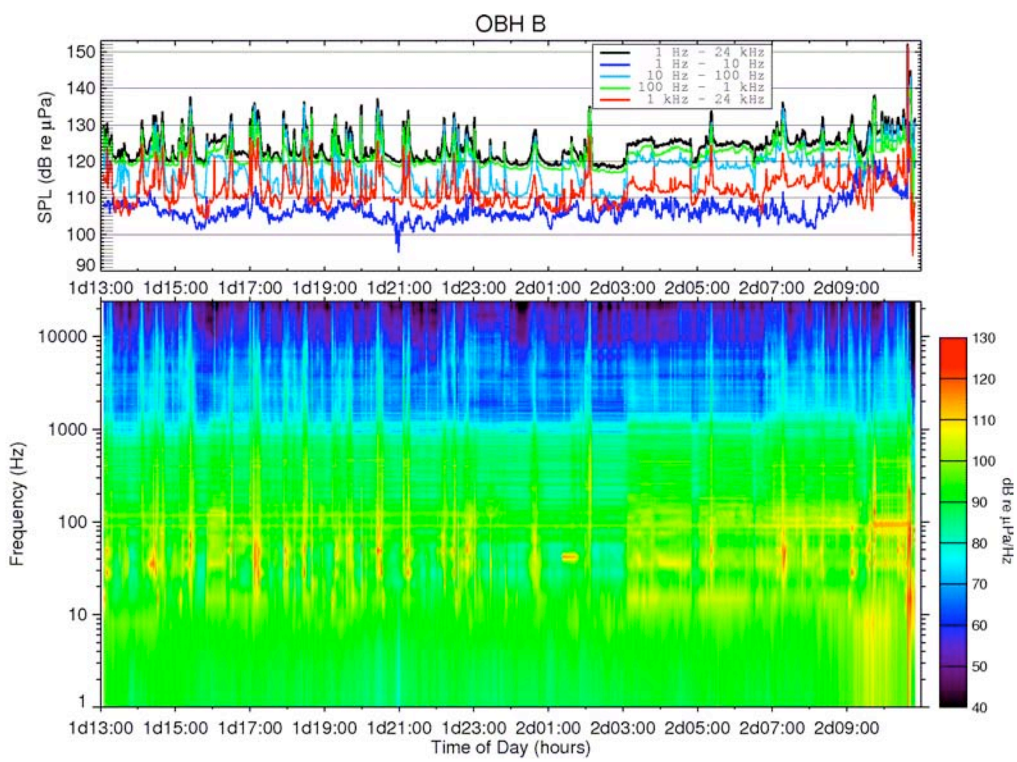

Figure 6: Spectrogram and band levels from OBH-B for a 22-hour monitoring period, September 15-16, 2006.

Coal Loading Noise

Loading of coal into the holds of *Pierre LD* continued throughout the time period of this acoustic study. The actual loading process produced relatively less noise than the carrier itself and the conveyor drive system except during the first two minutes of loading into an empty hold. The characteristics of loading noise are evident in Figure 7, which shows the spectrogram and band levels through a 10-minute period during which loading into an empty hold began. Underwater noise levels increased abruptly by more than 20 dB to over 140 dB re μPa on OBH-B as the coal fell into the empty hold. The noise level then dropped by about 10 dB within 30 seconds, and by a further 10 dB back to background levels within 2 minutes. The background levels were due primarily to carrier self-noise and to conveyor drive noise. Interestingly the initial loading noise includes a high frequency (above 1 kHz) component for the first few seconds. This noise is probably from the actual striking of coal against the metal of the hold. This high frequency noise quickly dropped in level as the bottom of the hold became covered with coal. Sound levels in the dominant 100 Hz – 1 kHz band dropped to background (120 dB) within 2 minutes. Sound levels in the 10 Hz – 100 Hz band remained 2 to 5 dB above the corresponding background level (110 dB re μPa) through the remainder of loading.

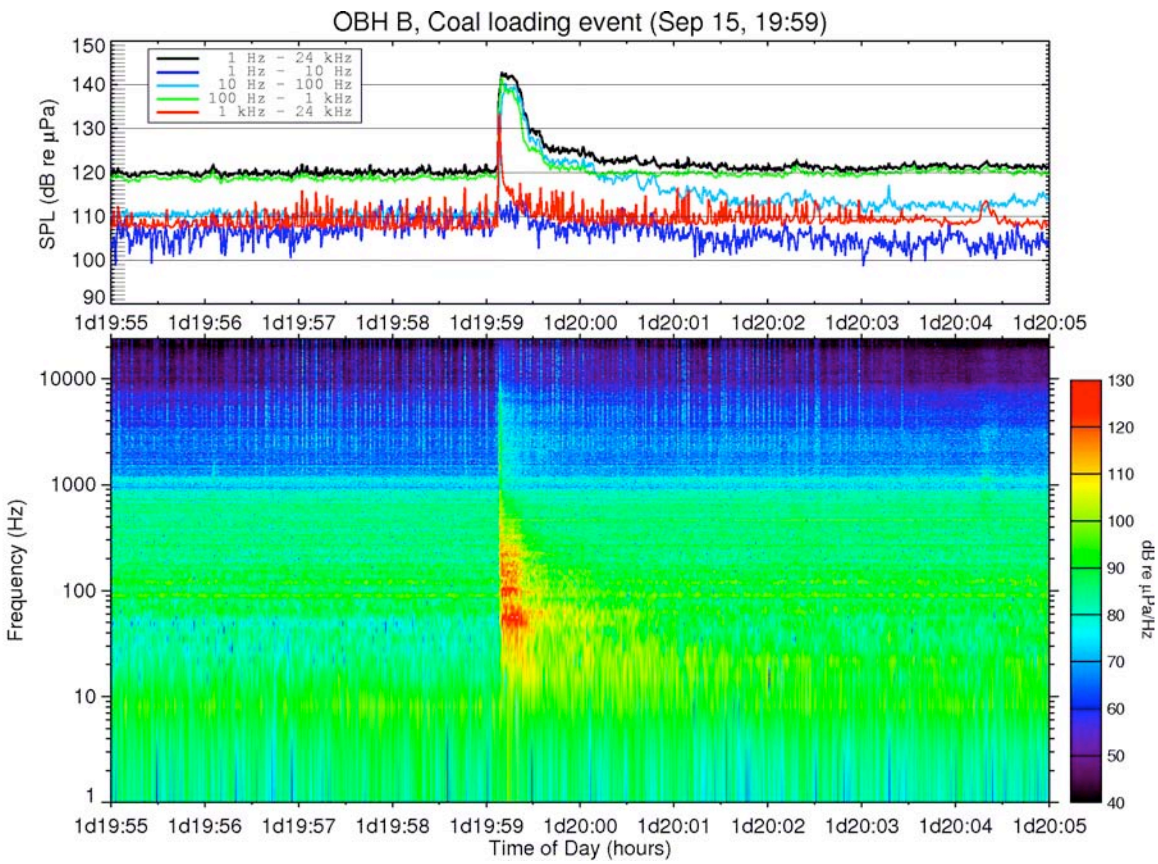

Figure 7: Spectrogram and band levels at OBH-B 5 minutes prior to and 5 minutes after the start of coal loading into an empty hold (loading began shortly after 19:59).

Noise level statistics

Sound level data were analyzed to compute percentile sound levels for representative daytime (14:00-20:00, 15 September), nighttime (0:00-06:00, 16 September), and full-day (13:30, 15 September – 10:30, 16 September) time periods. Percentiles represent the thresholds in decibels that sound levels were below for the given percentile percent of the time. For example, the 70th percentile sound level on OBH-A between 0:00 and 06:00 on 16 September was 120.4 dB re μPa. This means that sound levels were below 120.4 dB re μPa for 70% of the time, and above this level for the remaining 30% of the time. The use of percentile levels allows us to assess the general noise conditions by excluding short-duration events, such as vessel passes. A good measure of the representative normal terminal levels is given by the percentile levels below the 70th percentile because other (not related to terminal operations) noise sources were present for less than 30% of the time.

Sound level percentile histograms, showing percent of 1-minute samples versus sound levels in 1 dB bins, are presented in Figure 8. The most noticeable difference of the histogram characteristics between daytime and nighttime is the spread of sound levels to higher values during the daytime. This is a direct result of the presence of ferry and other vessel transit noise during the day. The nighttime histograms are most representative of the noise level distribution caused by the WestShore terminal and therefore also of the noise levels that will be present near the Ladd terminal. The nighttime 70th percentile levels were 124.9 dB re μPa on OBH-B and 120.4 dB re μPa on OBH-A. All of the sound contributing to these levels is attributed to coal terminal operations.

If it is assumed that all noise originated at the conveyor drive motor location, then the equivalent 70th percentile source level for all terminal noise would be 174.5 dB re μPa at 1m. The above assumption is consistent with the observed difference in levels measured on the two OBH systems; the difference of 4.5 dB is expected if the source was located 300 m and 500 m from the respective systems. It would have been much larger (about 12 dB) if the source was near the berth at 100 m and 400 m respectively from the OBH positions.

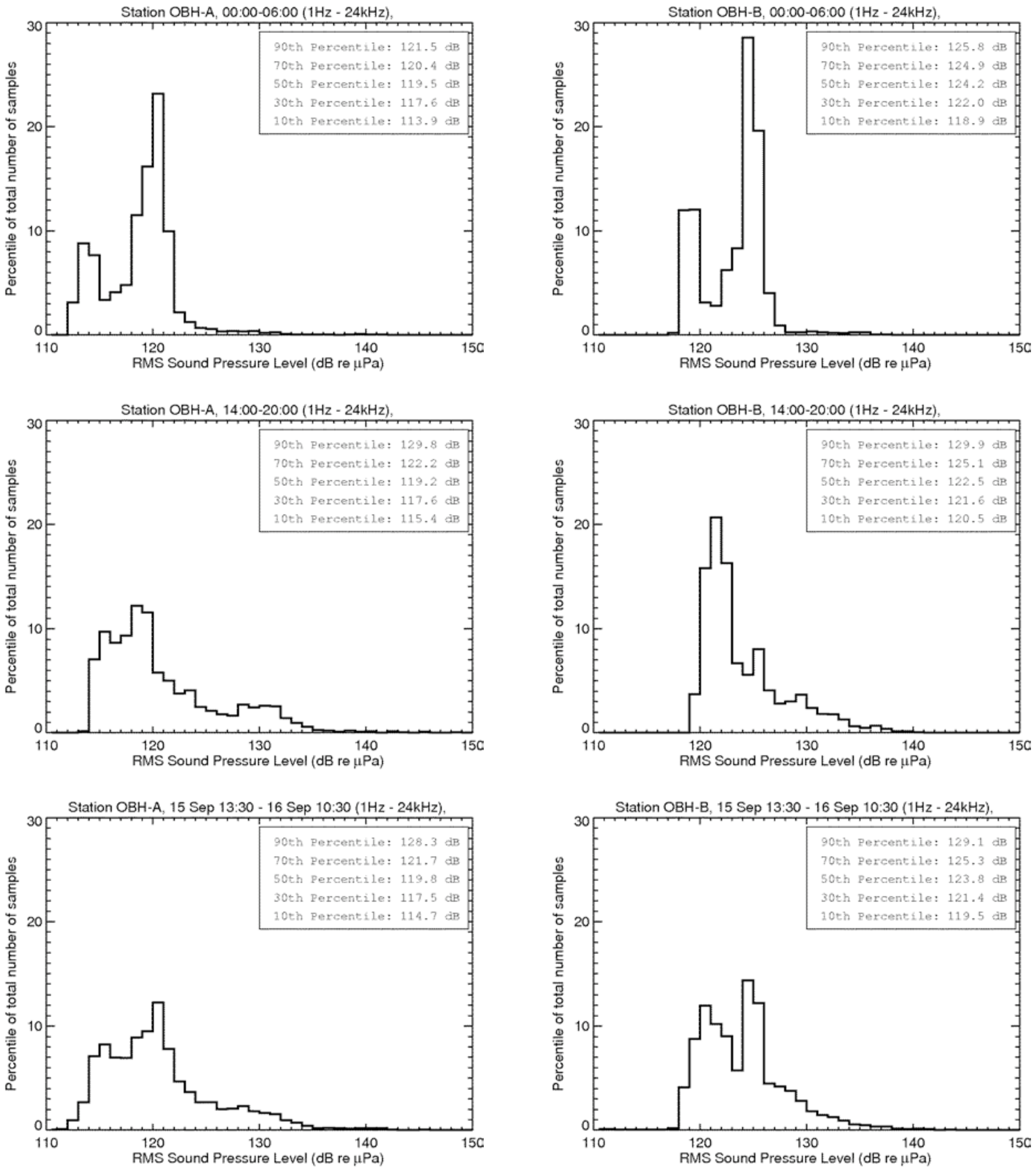

Figure 8: Sound level percentile histograms for daytime and nighttime periods, WestShore terminal, September 15-16, 2006.

Sound Modeling

Sound propagation models are useful for predicting the spatial variation of noise levels from sounds produced at known locations. A modeling approach was applied to predict spatial variation of noise levels in vicinity of the WestShore terminal based on the measured levels at the OBH locations. JASCO Research Ltd's Marine Operations Noise Model (MONM) was used for this purpose. MONM is a parabolic equation finite difference model that accounts for spectral characteristics of the source and the geoacoustic parameters of the ocean environment. It specifically treats bathymetric effects, ocean sound speed profile, compressional and shear wave speed and attenuation profiles of the seabed, and density profile of the seabed. The model uses a 2-D computational engine that is run along many radials to compute the three dimensional field. This approach is commonly referred to as Nx2D modeling.

MONM requires the sound source levels in 1/3-octave bands. These levels were derived from the measurements from the OBH systems during normal coal loading operations into partially-full holds as described in the previous sections. Back-propagation of the 1/3-octave measured levels from OBH-B to a source at the conveyor drive location was performed using point-to-point runs of the propagation model for each band center frequency. Back-propagation assumed the source was at 7 m depth, which was approximately mid-water depth at the conveyor drive location, and the receiver was on the bottom. The resulting 1/3-octave band source levels are given in Table 1.

Table 1: 1/3-octave band source levels for typical terminal operations, including coal conveyor drive systems, loading noise, and vessel noise from its propulsion system assisting with holding berth position.

Frequency (Hz)	Source Level (dB re μPa // 1m)	Frequency (Hz)	Source Level (dB re μPa // 1m)
0010	146.3	0315	159.2
0013	148.4	0400	161.3
0016	153.8	0500	160.6
0020	151.8	0630	159.2
0025	154.8	0800	158.6
0032	155.6	1000	157.0
0040	159.1	1250	153.4
0050	156.3	1600	148.2
0063	156.6	2000	146.7
0080	157.3	2510	148.3
0100	161.5	3160	147.3
0125	160.0	3980	145.1
0160	159.7	5010	145.4
0200	158.7	6310	147.0
0250	159.4	7950	145.2

The source levels given in Table 1 were input to MONM and the model was run to generate sound level isopleths for an 8 km by 8 km square area surrounding the terminal. The model results are representative of a receiver at 10 m depth. The source depth was specified at 7 m. Water sound speed profile was based on a principal component analysis of CTD casts by Canadian Department of Fisheries and Oceans (unpublished) for the Fraser river delta region of Georgia Strait. The seabed geoacoustic profile was obtained from sediment core data obtained on the Fraser River Delta. Modeling results are presented in the sound level isopleth map in Figure 9. The approximate distance to 120 dB re μPa is 1.2 km in the offshore and alongshore directions, and approximately 500 m in the inshore direction. The lower sound levels in the inshore direction are a result of low frequency sound propagation being preferentially better supported in deeper water. This is also the reason that the isopleths extend farther in the dredged channel northeast of the berth than the not-dredged area in the northwest direction.

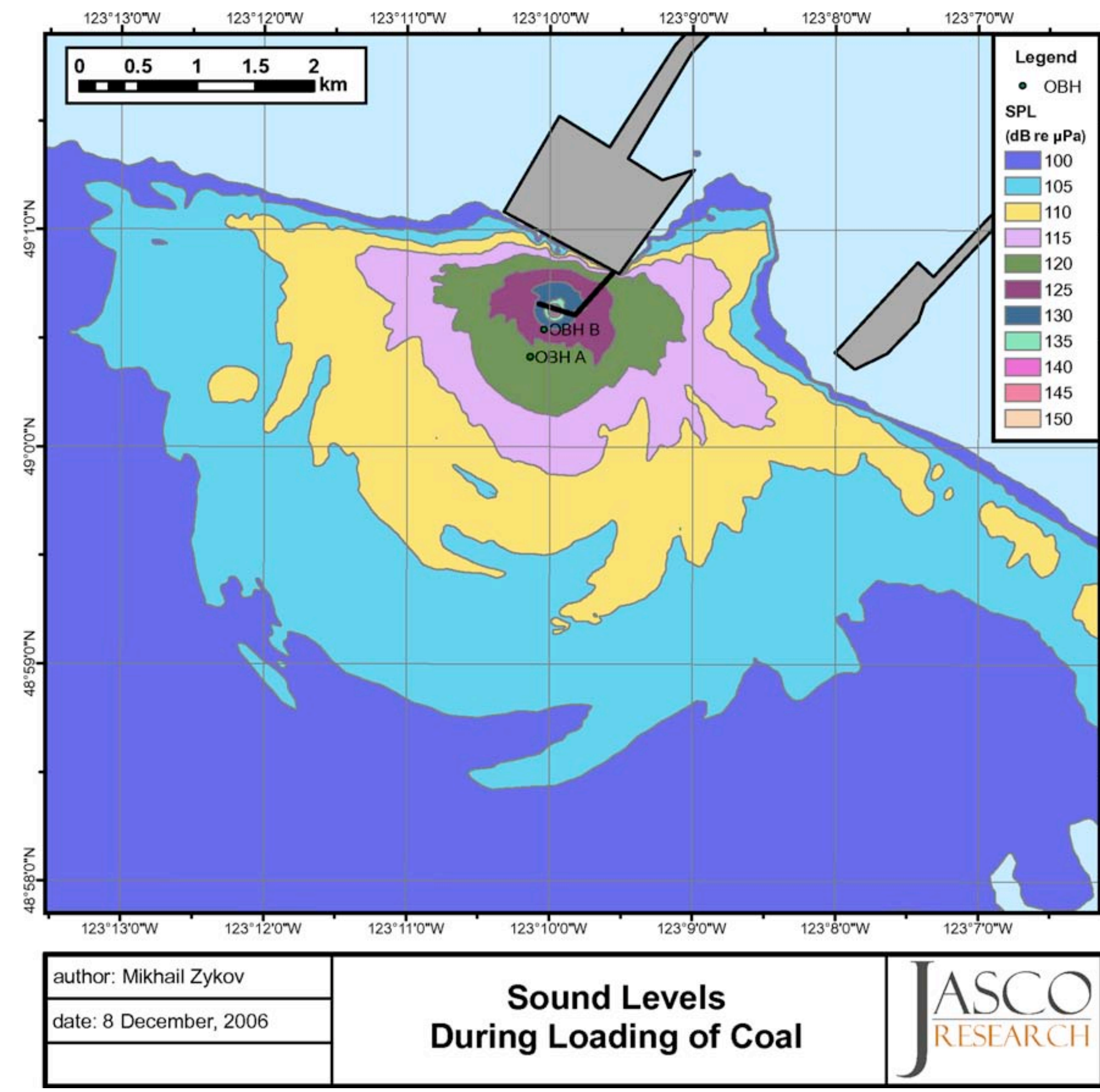

Figure 9: Noise model results for terminal operations showing sound pressure isopleths in the vicinity of the WestShore terminal.

Summary

Sound level measurements were made 100 m and 400 m from the south berth of WestShore terminals Ltd Roberts Bank marine coal terminal in Delta, British Columbia, Canada, for the purpose of quantifying expected sound levels that will be present near DRven's Ladd terminal in upper Cook Inlet, Alaska. The measurements were made using two autonomous Ocean Bottom Hydrophone (OBH) systems deployed on the seabed over a 22-hour period starting 13:00 on 15 September 2006 while loading of the coal carrier *Pierre LD* was in progress. The measurements captured noise produced by coal falling into the carrier's holds during the loading process as well as noise produced by the carrier's propulsion system and noise produced by the terminal's conveyor drive system. Conveyor drive motor noise was conducted into the water by the pilings that supported the conveyor trestle.

The coal loading process itself was relatively quiet except for brief periods, lasting a few seconds, when the coal was loaded into empty holds. This noise was produced by the coal striking the metal bottom of the hold and it decreased quickly as the bottom of the hold became covered in coal. The initial broadband noise level increased abruptly from background level of 121 dB re μPa to 143 dB re μPa at 400 m range as coal loading started. The "background" noise was due primarily to carrier self-noise and to conveyor drive noise. After one minute the level at 400 m dropped to 125 dB re μPa, and after 3 minutes it reached the steady-state loading level near 122 dB re μPa.

The most significant source of underwater noise at the WestShore terminal was a pile-supported drive motor that drove the conveyor belt systems that deliver coal to the berth and loader. The noise from this motor, as received underwater, is characterized by a series of tonals between 100 Hz and 1 kHz. The effective acoustic source level[1] for this motor was calculated by back-propagating the measured sound levels from the two OBH deployment positions to the motor location. This was approximately 174.5 dB re μPa at 1m.

The source level of underwater noise produced by the carrier's propulsion system approached that of the conveyor drive motor, approximately 166 to 173 dB re μPa at 1 m, when the carrier had to use its propulsion system to assist in maintaining position at the berth as wind speeds became strong. However, this sound was emitted more directly into the water as compared to the drive motor sound.

JASCO's Marine Operations Noise Model (MONM) was applied to compute the spatial variability of noise levels in vicinity of the WestShore terminal using the

[1] Source level here refers to the sound pressure level near a point-like sound source that would produce the actual sound levels measured at the OBH locations. The source level is referenced specifically to the pressure at 1 meter from the point source. At the WestShore terminal, noise from the conveyor drive system was emitted into the water by several of its supporting piles in about 14 m of water. Although this source configuration differs from the point source representation, the point source level is still very useful for predicting sound levels at other locations. It is important to note, however, that nowhere in the water does the actual received sound reach as high as the calculated source level of 174.5 dB.

measured 1/3-octave band source levels (including both the vessel noise and the conveyor drive noise). The model results are presented as a map of sound level isopleths. The model results show that, at the WestShore terminal, sound levels are higher in the offshore direction and in one direction towards shore that was dredged deeper than surrounding inshore areas. The model results predict that the 120 dB re μPa isopleth occurs approximately 1.2 km in the offshore and alongshore directions, and approximately 500 m in the inshore direction, from the berth.

Discussion

Ambient sound levels measured in six areas of upper Cook Inlet and away from industrial activity averaged 95 dB re 1 μPa, and up to a maximum of 124 dB at Point Possession during an incoming tide (Blackwell and Greene 2002). At Port Mackenzie, across the inlet from the Port of Anchorage and an area frequented by beluga whales, "ambient" sound levels (presumably not completely devoid of some industrial sounds) ranged from 115 to 133 dB during low tidal currents and 125 to 132 dB during incoming and outgoing tides (Blackwell 2005). It seems likely that, during some parts of the tide, broadband sound levels produced from the operation of a coal loading facility at Ladd would be similar to those during periods of high tidal flux within as little as 100m. At quieter stages of the tide, unmitigated broadband sounds from the terminal would be above broadband ambient levels (95 dB) for up to 10 km. It is reasonable to assume that design engineering to dampen or attenuate sounds produced from the conveyor motor could reduce its effective source level by 10 dB; such a reduction would decrease the distance to where broadband would reach 95 dB down to about 3.3 km.

The National Marine Fisheries Service (NMFS) currently uses 160 dB re 1 μPa SPL as a threshold for *pulsed* sounds that would constitute "disturbance" to marine mammals. Noise produced from pile driving is considered a pulsed sound. However, for continuous or extended-duration sounds, like those that would be produced from coal loading, it is commonly assumed by NMFS that disturbance is possible at received levels > 120 dB re 1 μPa. This criterion is based mainly on early studies of gray and bowhead whale reactions to industrial sounds. The 120 dB value has also been used as a disturbance criterion for impact assessments for pipeline construction noise on gray whales offshore of Sakhalin Island. The criterion may be overly conservative for belugas, which have significantly lower hearing sensitivity to the low sound frequencies that dominate the terminal noise emissions as compared with the baleen whales for which the 120 dB criterion was developed. Beluga responsiveness has been shown to be highly variable in different situations; there are documented cases when belugas have shown strong avoidance to continuous sounds with received levels <120 dB, but there are other documented cases where they tolerated considerably stronger sounds.

The presence of broadband industrial sounds above ambient levels does not necessarily mean that they will have an effect or that they will even be heard by marine mammals found in the area. The broadband sounds measured at WestShore terminal were made up predominantly of low frequency components at frequencies well below 1 kHz. Seals and especially beluga whales (and other toothed whales) are considerably less sensitive to these low frequency sounds as compared to higher frequencies (Richardson et al. 1995). In assessing potential impact to whales and seals in the area, a more appropriate measure than broadband sound levels relative to broadband ambient noise levels would be the distance to which the industrial sound would be above the animal's hearing threshold in one or more frequency bands. These species-specific distances at which the industrial sound would fall below the hearing threshold can be estimated based on the frequency composition of the industrial sound, its rate of attenuation with distance (which usually depends on frequency), and the audiogram for each species. Audiograms of belugas, harbor porpoises and harbor seals are known and could be used for such calculations. For those marine mammals that frequent upper Cook Inlet, the distances at which the animals could actually hear or detect the stronger components of the industrial sound could be either more or less than the distance at which broadband sound levels attenuate to broadband ambient.

Recommendations

Our study found that the two primary underwater noise sources at the WestShore terminal were the drive motor of the pile-supported coal conveyor system, and the coal carrier vessel itself. The carrier noise was produced by its propulsion system as it was used to maintain berth position in moderate winds. Noise from the coal loading operation was also detected, but this noise generally was lower in amplitude. However, high level transient noise, lasting up to two minutes, was generated when coal was loaded into empty holds. Most of the energy in the industrial sound was below 1 kHz. Based on these observations we provide the following preliminary recommendations for assessing potential impacts and reducing and mitigating underwater noise effects from the Ladd terminal:

1.) Use audiograms from marine mammal species in the area, along with available data on frequency-composition of the industrial sounds, to calculate the distance by which sound levels in all 1/3rd octave bands drop below the hearing thresholds at those frequencies.

2.) Consider sound dampening technology in the design of the conveyor and its drive system.

3.) Consider designs for the berth orientation and anchoring system that minimize the need for vessel propulsion to maintain the ships position.

Literature Cited

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Appendix A: Hourly Weather

Location: Vancouver International Airport (20 km North of Roberts Bank).

Hourly Data Report for September 15, 2006										
Time	Temp °C	Dew Point Temp °C	Rel Hum %	Wind Dir 10's deg	Wind Spd km/h	Visibility km	Stn Press kPa	Hmdx	Wind Chill	Weather
00:00	10.8	9.3	90		0	32.2	100.61			Mostly Cloudy
01:00	10.9	9.1	89	9	4	24.1	100.64			Mostly Cloudy
02:00	10.8	9.2	90	9	6	24.1	100.65			Rain Showers
03:00	11.0	9.2	89	10	6	24.1	100.66			Rain Showers
04:00	10.7	9.3	91	10	4	24.1	100.65			Rain Showers
05:00	10.8	9.6	92	9	6	24.1	100.69			Cloudy
06:00	11.0	9.5	90		0	24.1	100.72			Rain Showers
07:00	11.5	9.8	89	11	7	24.1	100.75			Rain Showers
08:00	12.4	10.1	86	11	6	24.1	100.75			Rain Showers
09:00	12.8	10.1	84	20	7	24.1	100.82			Cloudy
10:00	14.0	10.5	79	23	9	24.1	100.85			Mostly Cloudy
11:00	15.3	10.5	73	25	15	24.1	100.89			Mostly Cloudy
12:00	14.2	10.2	77	27	15	24.1	100.92			Cloudy
13:00	13.8	11.3	85	29	15	24.1	100.95			Rain Showers
14:00	14.5	9.9	74	28	15	32.2	100.96			Rain Showers
15:00	16.4	9.1	62	30	9	32.2	100.97			Mostly Cloudy
16:00	16.4	8.4	59	25	9	32.2	100.99			Mainly Clear
17:00	16.0	6.8	54	30	13	32.2	101.03			Mainly Clear
18:00	13.7	6.9	63	29	7	48.3	101.07			Mainly Clear
19:00	12.4	6.9	69	35	4	48.3	101.11			Mainly Clear
20:00	12.4	8.1	75		0	48.3	101.17			Mainly Clear
21:00	11.3	7.5	77	8	7	48.3	101.21			Mainly Clear
22:00	12.7	7.7	72	10	6	48.3	101.27			Mainly Clear
23:00	11.2	7.8	80	8	9	32.2	101.34			Mostly Cloudy

Hourly Data Report for September 16, 2006											
Time	Temp °C	Dew Point Temp °C	Rel Hum %	Wind Dir 10's deg	Wind Spd km/h	Visibility km	Stn Press kPa	Hmdx	Wind Chill	Weather
00:00	10.0	7.6	85	9	9	32.2	101.42			Mainly Clear
01:00	10.2	7.7	84	11	11	32.2	101.46			Mainly Clear
02:00	10.4	8.5	88	11	17	32.2	101.52			Mainly Clear
03:00	10.1	8.4	89	10	15	32.2	101.57			Mostly Cloudy
04:00	10.1	8.2	88	9	15	32.2	101.62			Mostly Cloudy
05:00	9.9	7.6	86	10	15	32.2	101.70			Mostly Cloudy
06:00	10.0	7.2	83	10	15	32.2	101.76			Mostly Cloudy
07:00	10.0	6.5	79	11	13	32.2	101.83			Mostly Cloudy
08:00	12.7	6.7	67	13	22	32.2	101.88			Mostly Cloudy
09:00	14.2	7.9	66	11	17	32.2	101.94			Mostly Cloudy
10:00	15.2	8.0	62	14	20	32.2	102.00			Mainly Clear
11:00	15.8	8.5	62	16	17	32.2	102.02			Mainly Clear
12:00	16.9	8.5	58	16	20	32.2	102.03			Mainly Clear
13:00	17.2	3.9	41	15	17	32.2	102.02			Mainly Clear
14:00	17.4	9.0	58	21	19	32.2	102.03			Mainly Clear
15:00	17.9	8.0	52	19	15	32.2	102.04			Mainly Clear
16:00	17.5	6.6	49	21	17	32.2	102.05			Mainly Clear
17:00	17.3	7.4	52	17	17	32.2	102.07			Mainly Clear
18:00	16.5	7.1	54	15	11	48.3	102.10			Mainly Clear
19:00	12.9	8.0	72	10	15	32.2	102.12			Mainly Clear
20:00	12.4	8.1	75	9	11	32.2	102.18			Mainly Clear
21:00	12.8	8.3	74	9	13	32.2	102.18			Mainly Clear
22:00	12.3	8.5	78	8	11	32.2	102.20			Mostly Cloudy
23:00	11.5	8.3	81	10	13	32.2	102.19			Mostly Cloudy

Hourly Wind Speed for September 15, 2006	Hourly Wind Speed for September 16, 2006