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March 13, 2014

SUBMITTED VIA EMAIL TO: smith.scott@deq.state.or.us

Scott A. Smith
811 SW 6th Ave.
Portland, Oregon 97201

Re: Comments on Columbia Pacific Bio-Refinery's Proposed Oil Spill Contingency Plan

Dear Mr. Smith:

The Northwest Environmental Defense Center (NEDC) submits the following comments regarding the oil spill contingency plan proposed by Cascade Kelly Holdings, LLC, also known as Columbia Pacific Bio-Refinery (CPBR), located at 81200 Kallunki Road, Clatskanie, Oregon 97016, at mile 53 of the Columbia River. NEDC is a nonprofit environmental organization dedicated to protecting and conserving the environment and natural resources of the Pacific Northwest. A spill or accident at CPBR would be devastating to the Columbia River and the wildlife that depends on it, including endangered salmon populations. CPBR's operations pose a threat to the ecology of the region, neighboring communities, and the businesses that depend on clean water in the Columbia River. Recognizing the irreparable harm that would result from an accident at this site, NEDC urges DEQ to impose stringent precautionary requirements in CPBR's oil spill contingency plan that go above and beyond the federal and state minimum requirements for a Facility Response Plan (FRP).

Background

CPBR transfers un-denatured ethanol or denatured ethanol produced at its facility to barge vessels on the Columbia River. CPBR also receives light sweet crude oil and other ethanol products by rail and transloads that material to barges on the Columbia River. CPBR's facility houses two 3,800,000 gallon above-ground storage tanks, and has a total storage capacity of over 8 million gallons of oil. In November of 2012, CPBR began transloading unit trains of crude oil estimated to be 7,000 barrels per day. *See* Emerging Risks Task Force, *Emerging Risks Task Force Report – 2013*, available at http://www.rrt10nwac.com/Files/FactSheets/131217071637.pdf (attached hereto as Exhibit 1). That number is set to increase, following the Port of St. Helens' commissioners' authorization to double the number of monthly trains calling at the export dock. *See* Lyxan Toledanes, *Port of St. Helens commissioners approve increase to train traffic*, The Daily News Online (Nov. 2013) (attached hereto as Exhibit 2). The Port as well as cities like Rainier will now see up to 34 unit trains per month slicing through their communities, carrying loads of dangerous crude oil.

Nationally, the rapid increase in crude oil shipments by rail has increased the risk of oil spills from rail transportation. *See* U.S. Congressional Research Service, John Frittelli *et al.*, *U.S. Rail Transportation of Crude Oil: Background and Issues for Congress*, R43390 (Feb. 2014) (attached hereto as Exhibit 3). Due to its volatility, Bakken crude poses a considerable threat of fire and explosion, which is a major threat to public health and safety. *See* Exhibit 1, page 21. Such risks pose an immediate threat to the Columbia River and the wildlife that depends on it. Crude oil is among the most persistent and environmentally damaging type of oil and is very difficult to clean up. *See* Tom Fitzsimmons, *et al.*, *Oil Spills in Washington State: A Historical Analysis*, Washington Department of Ecology Pub. No. 97-252 (March 2007) (attached hereto as Exhibit 4). *See also* Exhibit 1, page 23 (explaining that due to its unique characteristics and relatively recent and dramatic increase in volumes shipped, Bakken crude presents new and unique challenges to oil spill preparation and the response community in the Northwest). The fact that highly volatile materials are being shipped in unit trains further exacerbates the risk of harm.

As a result, NEDC has real concerns about the adequacy of the measures outlined in CPBR's proposed oil spill contingency plan. Over the past year it has become clear that federal and state minimum standards fail to provide the necessary assurances to alleviate the dangers inherent in the transport of crude oil by rail. *See, e.g.*, Exhibit 3, page 17. In 2007 Washington's Department of Ecology recognized that "to prevent spills, an organization may be expected to go beyond currently accepted industry practices." Exhibit 4, page 32. Rather than focusing on whether CPBR's oil spill contingency plan meets the bare minimums set forth by federal and state regulation, DEQ can and should require CPBR include additional precautions.

As demonstrated by the catastrophic oil leak on the Kalamazoo River in Michigan and lingering effects of the Exxon Valdez accident in Alaska, spill response measures simply serve to mitigate the harm. Thus the primary focus of any spill contingency plan should be on prevention instead of emergency response. The following sections highlight some of the major weaknesses in CPBR's oil spill contingency plan that DEQ should require CPBR to address before allowing it to continue transport operations at the facility.

Discussion

I. The oil spill contingency plan fails to address critical factors necessary to ensure public safety and protection of the environment.

First, CPBR's contingency plan should include more specific training and education measures for its own personnel and for local emergency responders. A report completed by Washington's Department of Ecology found that human error was the root cause of the majority of spills in Washington around 2007, and therefore such spills could have been prevented. *See* Exhibit 4, pages 32-33, 39. For example, in 2007 Kinder Morgan spilled approximately 58,800 gallons of synthetic crude from the Westridge Transfer Line into storm sewer systems in Burnaby, British Columbia and ultimately into Burnaby Harbor. Exhibit 1, page 18. It took the pipeline operator five minutes to shut down the pipeline, contrary to Kinder Morgan's standard shutdown procedures. *Id.* Thus regardless of the measures set forth in CPBR's contingency plan, those measures will only be effective if personnel are properly trained to implement the measures.

Second, CPBR's contingency plan fails to recognize or adequately address the risk of fire and explosion resulting from a spill. Bakken crude oil, a light sweet low viscosity crude oil, is highly flammable and easily ignites at normal temperatures by heat, static discharges, sparks or flames. Exhibit 1, page 14. Vapors may form explosive mixtures with air, travel to the source of ignition and flash back, or spread along the ground and collect in confined areas such as sewers and tanks. *Id.* Burning sweet light crude may create carbon monoxide, hazardous sulfur dioxide and related oxides, nitrogen oxides and smoke particulates. *Id.* The potential for Bakken crude to ignite in fire or explosion is the single largest risk to responders and public health. Exhibit 1, page 21.

Given the high volatility of Bakken crude, it is critical that CPBR's oil spill contingency plan outline specific fire response measures. Exhibit 1, pages 22-23. Recent studies and improper practices in recent accidents support that certain response measures are more effective at addressing crude oil fires than others. *Id.* at 21. For example, response measures should concentrate on isolating the spill or leak area, and downwind evacuations. *Id.* Use of water spray when fighting these fires may be inefficient, and instead responders should use dry chemical, CO_2, or regular foam for small fires, fog or regular foam for large fires, and allow containers to cool if the fire involves tanks. *Id.* at 22.

CPBR's contingency plan fails to address these specific measures. The proposed plan notes that CPBR maintains a Material Safety Data Sheet for the denatured ethanol, undenatured ethanol, and crude oil, which contains a list of firefighting measures and effective extinguishing agents. CPBR Proposed Plan, Appendix A. The plan goes on to explain that two methods for extinguishing fires are found near the dock: water or foam and fire extinguishers. *Id.* This terse description of fire safety measures is wholly insufficient to address the very real threat of fire resulting from CPBR's operations at the facility.

Third, CPBR's contingency plan should highlight the importance of increased safety and prevention measures at the material transfer locations. The risk of a spill is great at each point of transfer, because those locations involve the greatest potential for human error and require multiple variables to be in place for effective and safe transfer. At the CPBR facility, there are at least three major points of transfer: (1) from railcar to storage tanks at the adjacent onsite tank farm; (2) from storage tanks to the transfer facility; (3) from transfer facility onto the barge vessels. In addition to focusing on the transfer points, DEQ should require CPBR to coordinate this contingency plan with the emergency plans kept by the railroads, which will be bringing the crude oil to the port. There is necessarily an overlap between CPBR's transloading facility and the unit trains that bring crude oil into the facility. Ignoring this overlap ignores likely spill scenarios that should be backed by a coordinated and cohesive response plan.

Finally, it is unclear what additional measures CPBR has in place to identify spills occurring at night, other than staffing the incident commander (IC) on call 24 hours and using flashlights to monitor the area. Spills at night are a particular threat in that they can go unnoticed and it may be difficult to assess the extent of the spill. For example, the Enbridge Pipeline spill into the Kalamazoo River system happened at night and initial responders were not aware of the severity of the spill or the type of oil spilled. Exhibit 1, pages 16-17. DEQ should require CPBR to include additional safety measures to prevent spills at night and to identify the extent of such spills.

II. DEQ should require CPBR to keep more resources on site and commit funding for local emergency responders.

Access to resources, including equipment, training and education, is an essential element of the spill response portion of an adequate contingency plan. One of the main inadequacies of emergency response efforts identified for recent oil spills was the lack of or limited amount of resources available. *See* Exhibit 1, pages 16-21. For example, first responders to the Kalamazoo River oil spill in Michigan in 2010 did not have the resources to contain or control the flow of oil into surrounding bodies of water; lack of training on spill procedures contributed to the amount of oil spilled into Burnaby Harbor in 2007; and the limited amount of response equipment in close proximity to the spill magnified the environmental destruction resulting from the 2005 oil railcar derailment adjacent to Lake Wabamun in Canada. *Id.* CPBR's proposed contingency plan does not include the requisite commitments from CPBR to provide the resources necessary to quickly and appropriately respond to an accident at its facility.

CPBR's proposed contingency plan fails to provide the on-site resources necessary to respond to potential spills. Potential discharges include the worst case scenario of a major denatured ethanol or crude oil spill with secondary containment failure resulting in up to 3,800,000 gallons of release. CPBR Proposed plan, pages 18-19. The response equipment listed in CPBR's proposed plan includes a small quantity of shovels, rakes, brooms, squeegee, and safe radios as readily available hand tools to respond to an accident. *See* CPBR Proposed Plan, Appendix H. The plan lists only 10 spill drums with a capacity of 55 gallons located on the site. *Id.* The firefighting and personal response equipment is even more lacking. *Id.* The plan notes that CPBR does not maintain any skimmers or pumps on site but will rely instead on oil spill removal organizations (OSROs). This reliance is wholly inadequate. A facility with CPBR's capacity to store over 8 million gallons of oil on site should be required to maintain skimmers, pumps, and requisite firefighting equipment on site.

The lack of preparedness for this type of oil coming through the facility in such great quantities is exacerbated by the fact that CPBR intends to rely on OSROs to respond in the event of a major spill. As proven by recent oil spills, response time is essential to limiting damage of a spill. At the Kalamazoo River spill, not only did the Enbridge employees lack the requisite training (the company's personnel placed booms too far downstream to be effective and used booms that were incompatible with fast-moving water) or the necessary resources to contain or control the flow of oil into surrounding bodies of water, but the response from Enbridge's contractors took 10 hours. Exhibit 1, page 17. Here, CPBR will have an incident commander (IC) on all shifts to respond. *See* CPBR Proposed Plan, Appendix H. But like the Enbridge employees, CPBR's contingency plan does not appear to provide its IC with the necessary resources for an immediate response. CPBR's OSRO's include Cowlitz Clean Sweep and Clean Rivers Cooperative. *See* CPBR Proposed Plan, Appendix I. Cowlitz Clean Sweep is 20 miles from CPBR's facility. The agreement with Clean Rivers Cooperative states that it will provide 12- and 24- hour response zones. Thus CPBR intends to rely largely on OSROs that could take up to 24 hours to provide a response. Given the potential spills identified by CPBR itself, and understanding the volatile nature of the material, CPBR's plan lacks the resources necessary to adequately respond in the event of an accident.

Not only does CPBR lack the necessary on-site resources to respond to the spill scenarios identifies in the plan, but CPBR should be responsible for providing necessary resources to local and state emergency responders. CPBR's contingency plan directly relies on local emergency responders for potential fires and explosions. *See* CPBR Proposed Plan, Appendix F. Yet, CPBR's facility and the materials it handles are one of a kind in this region. As noted above, fires involving crude require special foam. That foam is expensive. Rob Davis, *For oil trains crossing Oregon, Washington, state oversight gaps raise questions in wake of accidents*, The Oregonian (Jan. 2014) (attached hereto as Exhibit 5). There is no reason for rural fire districts to have large amounts of this type of material on hand.

It is truly incredible that CPBR expects local firefighters and emergency responders in the region to obtain the specialized training and equipment necessary to respond to hazardous substance spills on taxpayer dollars. DEQ is cutting back on oil spill training for employees, even though this facility has increased the volume of oil coming into the state and being transported along its iconic Columbia River. *See* Exhibit 5. Understanding the state and local governments have limited resources, CPBR should bear the costs for local emergency responders and state agencies to obtain training and equipment to respond to the threats created by CPBR's activities. This is not an appropriate cost for Oregon's taxpayers.

Requiring up front funding from CPBR for precautionary measures is reasonable, given the likely costs of clean up. In Michigan, the Kalamazoo spill cost Enbridge more than $1 billion and the company is still working on cleanup three years later. Max Paris, *Enbridge's Kalamazoo cleanup dredges up 3-year-old oil spill*, CBS News: Politics (Sept. 2013) (attached hereto as Exhibit 6). Federal agencies spent almost $60 million on the cleanup efforts, a cost born by taxpayers. U.S. Environmental Protection Agency, Region V, *Pollution/Situation Report #198*, Feb. 2014 (attached hereto as Exhibit 7). In

British Columbia, it cost $15 million to recover 1,321 barrels of the 1,400 barrels of synthetic crude that Kinder Morgan's pipeline spilled into Burnaby Harbor. *See* Exhibit 1, page 18. CPBR should provide funding for any specialized training and additional resources required by local emergency responders to react to a spill at the facility. Requiring such up-front costs is reasonable because it will reduce the amount required to be spent in response to an accident.

Conclusion

In reviewing CPBR's contingency plan, DEQ is faced with ensuring CPBR provides sufficient measures to safeguard Oregon's environment and communities. As explained in the comment, simply requiring the minimum standards set forth in outdated federal and state regulations will not be enough. Further, CPBR has a history of ignoring Oregon's environmental regulations. The company operated its facility for more than a year under an improper air permit. DEQ can and should require more stringent measures in CPBR's oil spill contingency plan. A single accident at a facility of this size and nature would be catastrophic to the region. Ignoring the dangers at this stage is not worth that risk.

Sincerely,

Marla Nelson
Legal Fellow

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)

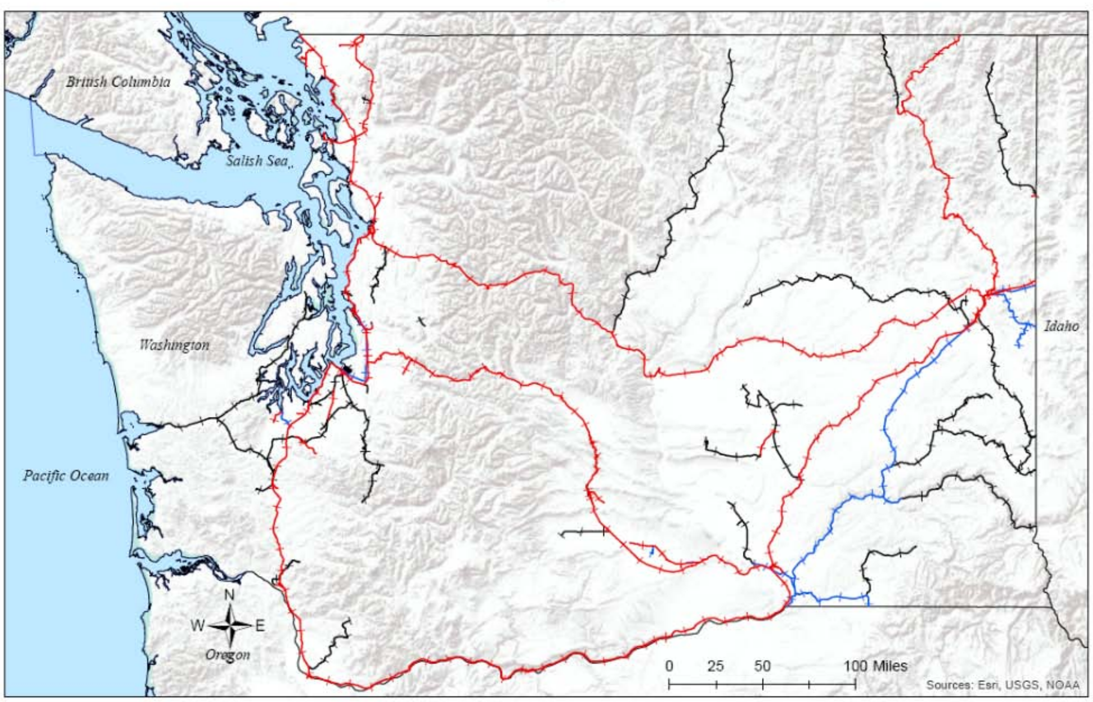
Imperium Terminals (Hoquiam, WA) Imperium, a renewable fuels producer, is exploring a crude oil handling facility at the Port of Grays Harbor at the firm's existing site at Terminal 1. The company is proposing to spend $45 million constructing nine 80,000-gallon storage tanks and other facilities by 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



Legend

Owner Other Burliington Northern Santa Fe Union Pacific

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

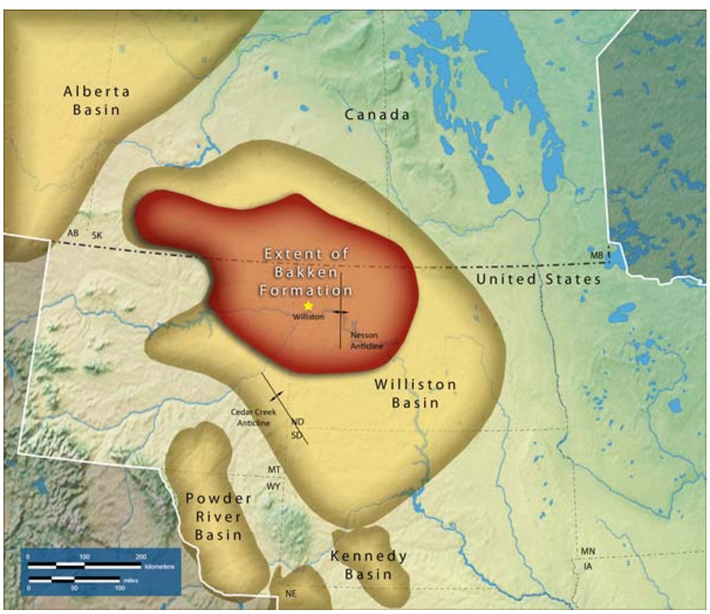
water, saturated with a dense and extremely viscous form of petroleum technically referred to as bitumen (or colloquially “tar” due to its similar appearance, odor and color). Natural deposits are found in extremely large quantities in Canada, some 177 billion barrels or nearly 71 percent of global reserves.

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.

Kalamazoo River Spill

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:
Sandpoint, Id. to Spokane, Wash. (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.

Stevens Pass / Cascade Tunnel - 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.

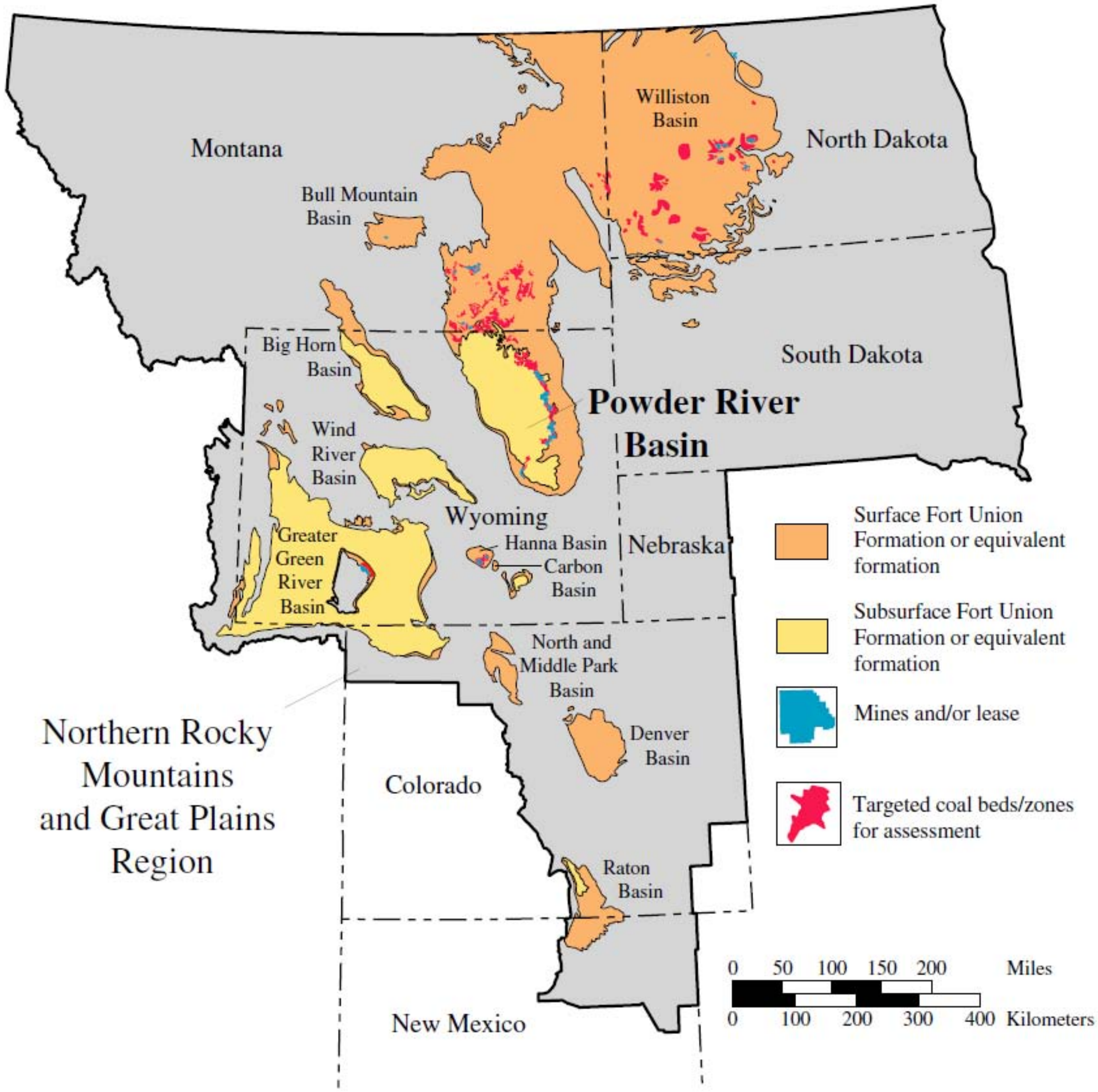
Should these various rail to terminal projects be permitted and built, there will be an associated increase in vessel traffic to move the coal out of the state (or out of Canada through U.S. waters). It is not certain but expectations are for an associated increase in bunkering with the increase in vessel 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	
Bituminous coal, Germany	127.6	28.7	Pies et al. (2007)
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, CH_4) 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 ±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.		

THE DAILY NEWS ONLINE, TDN.com, available at http://tdn.com/news/local/port-of-st-helens-commissioners-approve-increase-to-train-traffic/article_820acbb4-4c9e-11e3-a4e7-0019bb2963f4.html

Port of St. Helens commissioners approve increase to train traffic

November 13, 2013 4:00 pm • By Lyxan Toledanes

COLUMBIA CITY, Ore. — More crude oil and more jobs are coming to Columbia County following a decision by Port of St. Helens commissioners to double the number of trains allowed to call at Port Westward near Clatskanie.

More than 50 people showed up at the port commissioners' meeting, where board members approved Global Partners LP's request to allow up to 34 trains a month to call at its export dock.

Port Westward is the property of the Port of St. Helens, and commissioners only have control of the rail line leading into Port Westward. Portland & Western Railroad owns and controls the rest of the rail line.

Global Partners says it will invest up to $70 million to improve and expand rail lines at Port Westward, increase oil storage and unloading capacity and expanding the dock to boost crude oil shipments. Global Partners did not return calls for comment Wednesday, and a timeline for its efforts at Port Westward was not immediately available. Right now Global does not envision work off the Port Westward site.

"This opportunity came along which will actually improve the rail issue (at the port). It was the missing component," said Colleen DeShazer, treasurer for the Port of St. Helens Commission. "There was no money out there, and it's there now. That can't happen without the company putting the money there for us."

About 12 crude oil trains a month — bearing crude from the Baaken formation in North Dakota — are calling at Global's Port Westward terminal, five fewer than allowed. Without improvements, Port Westward cannot handle more than 24 unit trains per month, said Patrick Trapp, executive director for the Port of St. Helens.

Clatskanie Mayor Diane Pohl was among a majority of people in the meeting who favored expansion of the crude oil business, saying it would benefit the county's struggling economy. Global Partners says a rail improvement project will create 100 construction jobs and 30 permanent jobs.

"A Fortune 300 company can raise a lot of money," Pohl said. "They are a responsible company, and they should have the right to further invest in that property out there."

Opponents of the request to increase train traffic cited safety concerns. The derailment of two crude oil trains in Canada and one that exploded in Alabama on Friday highlighted the potential for similar accidents in Rainier's narrow and largely unprotected rail corridor on A Street.

Rainier officials did not attend Wednesday's meeting, but afterward they again voiced concerns about increasing rail traffic through town.

"This is a small town and trains are running right through. If we had a mishap like (in Alabama) it would take Rainier out, and it wouldn't take a whole lot," Rainier Councilwoman Judith Taylor said in a phone interview. "The safety issues outweigh the economic goal and the potential impact (an accident) can have at this time."

Rainier Mayor Jerry Cole said he was not surprised by the port's decision, but he hopes safety improvements can start in Rainier's rail corridor before train traffic increases. Cole said the city is working with the Oregon Department of Transportation, state Sen. Betsy Johnson and the rail company to bring about $7 million in safety projects to Rainier's A Street. Global has also shown interest in working with Rainier staff, Cole said Wednesday.

The Rainier City Council wants to install crossing guard arms along some A Street intersections, create a quiet zone and build an overpass at Veteran's Way for commuters to drive over train traffic. The city is seeking a $2 million ConnectOregon transportation grant to help finance the improvements.

"We realize here in Rainier (that) rail growth is inevitable, but at the same time we want our safety concerns addressed," Cole said. "We still want to keep Rainier a livable city. We look at it cautiously optimistic and hope that everything that's promised comes through."

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U.S. Rail Transportation of Crude Oil: Background and Issues for Congress

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CRS REPORT
Prepared for Members and
Committees of Congress

Summary

North America is experiencing a boom in crude oil supply, primarily due to growing production in the Canadian oil sands and the recent expansion of shale oil production from the Bakken fields in North Dakota and Montana as well as the Eagle Ford and Permian Basins in Texas. Taken together, these new supplies are fundamentally changing the U.S. oil supply-demand balance. The United States now meets 66% of its crude oil demand from production in North America, displacing imports from overseas and positioning the United States to have excess oil and refined products supplies in some regions.

The rapid expansion of North American oil production has led to significant challenges in transporting crudes efficiently and safely to domestic markets—principally refineries—using the nation's legacy pipeline infrastructure. In the face of continued uncertainty about the prospects for additional pipeline capacity, and as a quicker, more flexible alternative to new pipeline projects, North American crude oil producers are increasingly turning to rail as a means of transporting crude supplies to U.S. markets. According to rail industry officials, U.S. freight railroads are estimated to have carried more than 400,000 carloads of crude oil in 2013 (roughly equivalent to 280 million barrels), compared to 9,500 carloads in 2008. Crude imports by rail from Canada have increased more than 20-fold since 2011.

While oil by rail has demonstrated benefits with respect to the efficient movement of oil from producing regions to market hubs, it has also raised significant concerns about transportation safety and potential impacts to the environment. The most recent data available indicate that railroads consistently spill less crude oil per ton-mile transported than other modes of land transportation. Nonetheless, safety and environmental concerns have been underscored by a series of major accidents across North America involving crude oil transportation by rail—including a catastrophic fire that caused numerous fatalities and destroyed much of Lac Mégantic, Quebec, in 2013. Following that event, the U.S. Department of Transportation issued a safety alert warning that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.

Legislation introduced in Congress following the Lac Mégantic disaster would require railroads to have at least two crew members aboard all trains. In addition, policymakers are discussing regulatory changes involving tank car design, prevention of derailments, and selection of preferred routes for transporting oil by rail. Congress may evaluate these changes in the reauthorization of the Rail Safety Improvement Act of 2008 (P.L. 110-432).

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Introduction

North America is experiencing a boom in crude oil supply, primarily due to the growth of heavy crude production in the Canadian oil sands[1] and the recent expansion of shale oil production in North Dakota, Montana, and Texas. North American production now supplies 66% of U.S. crude oil demand, displacing crude from Latin America, Africa, and the Middle East.

This shift has led to significant challenges in transportation, as refineries that once received crude oil principally from oceangoing tankers are now seeing increasing deliveries by domestic transport. Existing pipeline capacity is, in some cases, insufficient to carry growing crude oil from some production areas, or does not link to the refineries needing the oil. The domestic barge network does not serve some key production regions located far from navigable waterways. As a quicker, more flexible alternative to new pipeline projects, North American crude oil producers are increasingly turning to rail as a means of transporting crude supplies to U.S. markets. Increased exports of refined products—and, if Congress changes the law, of crude oil—could lead to even larger volumes of oil being transported by rail. According to rail industry officials, U.S. freight railroads are estimated to have carried more than 400,000 carloads of crude oil in 2013, or roughly 280 million barrels, compared to 9,500 carloads in 2008.[2] Crude imports by rail from Canada have increased more than 20-fold since 2011.

The rapid increase in crude oil shipments by rail will likely increase the number of oil spills from rail transportation. However, the most recent data available indicate that railroads consistently spill less crude oil per ton-mile transported than other modes of land transportation. The amount of crude spilled per ton-mile of rail transport declined significantly between the early 1990s and the 2002-2007 period, the most recent years for which data are available.[3]

Nonetheless, the increase in rail shipments of crude has raised safety and environmental concerns. These concerns have been underscored by a series of major incidents involving crude oil transportation by rail, including a catastrophic fire and explosion in Lac Mégantic, Quebec, in July 2013 and a derailment in Casselton, ND, in December 2013 that led to a mass evacuation. Consequently, government agencies in the United States and Canada are considering new regulations related to oil transport by rail, and some Members of Congress have called for tighter rules governing crude oil railcars as well as a broader reconsideration of the role of rail in the nation's oil transportation infrastructure.[4]

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[1] The terms "oil sands" and "tar sands" are often used interchangeably to describe a particular type of nonconventional oil deposit. Opponents of the resource's development often use the term "tar sands," which arguably carries a negative connotation; proponents typically refer to the material as oil sands. The use of this term is not intended to reflect a point of view, but to adopt the term most commonly used by the primary executive-branch agencies involved in recent oil sands policy issues.

[2] Edward R. Hamberger and Andrew J. Black, "Freight Rail and Pipelines Deliver Energy for America," *The Hill, Congress Blog*, November 5, 2013, http://thehill.com/blogs/congress-blog/energy-environment/189187-freight-rail-and-pipelines-deliver-energy-for-america.

[3] Estimates by CRS based on data from Dagmar Etkin, *Analysis of U.S. Oil Spillage*, API Publication 356, August 2009, and Association of Oil Pipelines, *Report on Shifts in Petroleum Transportation: 1990-2009*, February 2012.

[4] See, for example, Office of Senator John Hoeven, "Hoeven to Meet Saturday with BNSF Railway President and CEO to Address Railroad Safety," press release, January 3, 2014.

Why Is Oil Moving by Rail?

In 2012, the United States produced 2.38 billion barrels of crude oil and imported another 3.10 billion barrels.[5] Canada has become the United States' leading foreign supplier, thanks to its increasing production from oil sands.[6] However, U.S. oil output has been increasing rapidly. In October 2013, U.S crude oil production exceeded imports for the first time since February 1995.[7]

The location of U.S. crude oil production has been changing rapidly. In particular, production in Alaska and from offshore sites has been declining, while production in Texas and North Dakota has been rising. The U.S. Geological Survey recently estimated that 2.7 billion barrels of light sweet crude oil remain in overlooked producing formations,[8] including the Eagle Ford shale, a prolific source of very light sweet crude oil in Texas, and the Bakken formation in North Dakota, a source of light sweet crude oil that rivals West Texas crude in quality.[9]

Almost all oil produced domestically, as well as some Canadian production, flows to one of the 115 U.S. refineries (**Figure 1**).[10] Nearly 45% of the country's refining capacity is located in the Gulf Coast, where 43 refineries process more than 9 million barrels of oil per day (bpd). However, the Midwest and the West Coast also have significant refining capacity.

[5] Energy Information Administration, *U.S. Crude Oil Supply & Disposition*, http://www.eia.gov/dnav/pet/pet_sum_crdsnd_k_a.htm. A barrel of oil is equal to 42 gallons.

[6] CRS Report CRS Report R43128, *Oil Sands and the Oil Spill Liability Trust Fund: The Definition of "Oil" and Related Issues for Congress*, by Jonathan L. Ramseur.

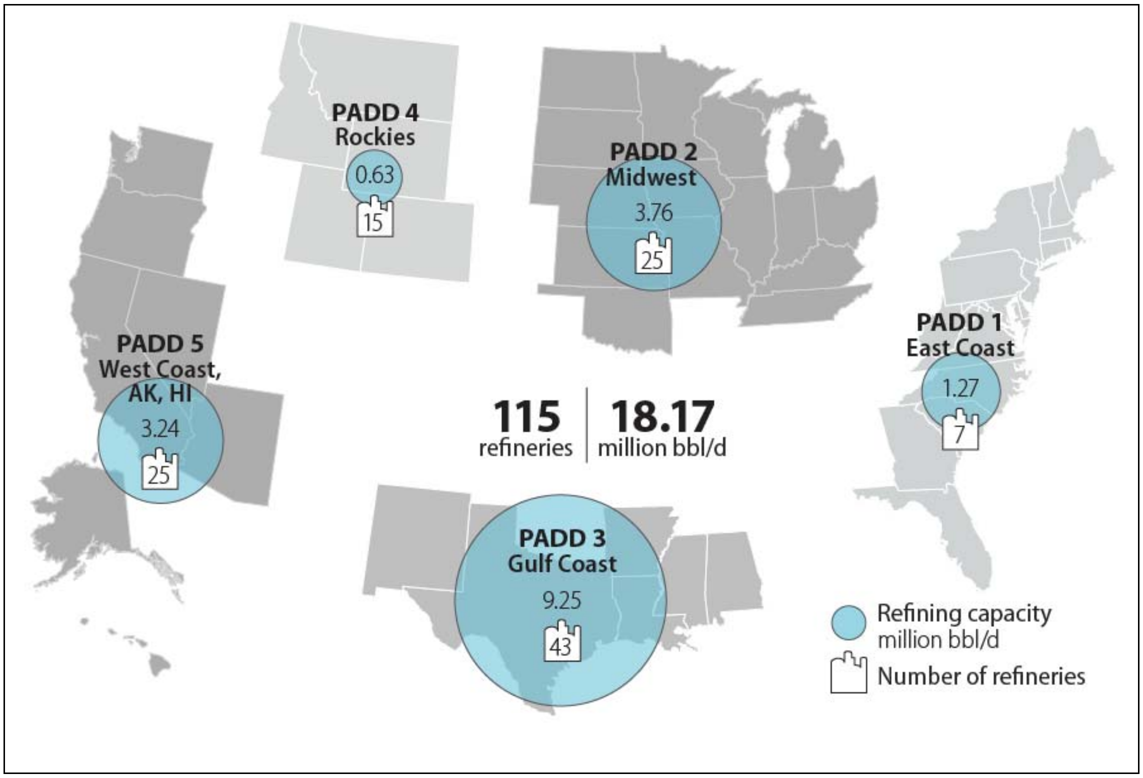
[7] "US Crude Production Tops Imports For The First Time Since 1995," *Oil Daily*, November 14, 2013.

[8] M. Tennyson, et al., *Assessment of Remaining Recoverable Oil in Selected Major Oil Fields of the Permian Basin, Texas and New Mexico*, 2012, USGS, http://pubs.usgs.gov/fs/2012/3051/.

[9] "Light" refers to oils with low specific gravity. "Sweet" refers to oils with low sulfur content. Light, sweet crudes are more valuable than heavier or sourer crude oils.

[10] For further information on the petroleum refining industry, refer to CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by Anthony Andrews et al.

Figure 1. U.S. Refinery Capacity by PADD in 2012



Sources: Congressional Research Service; Energy Information Administration.

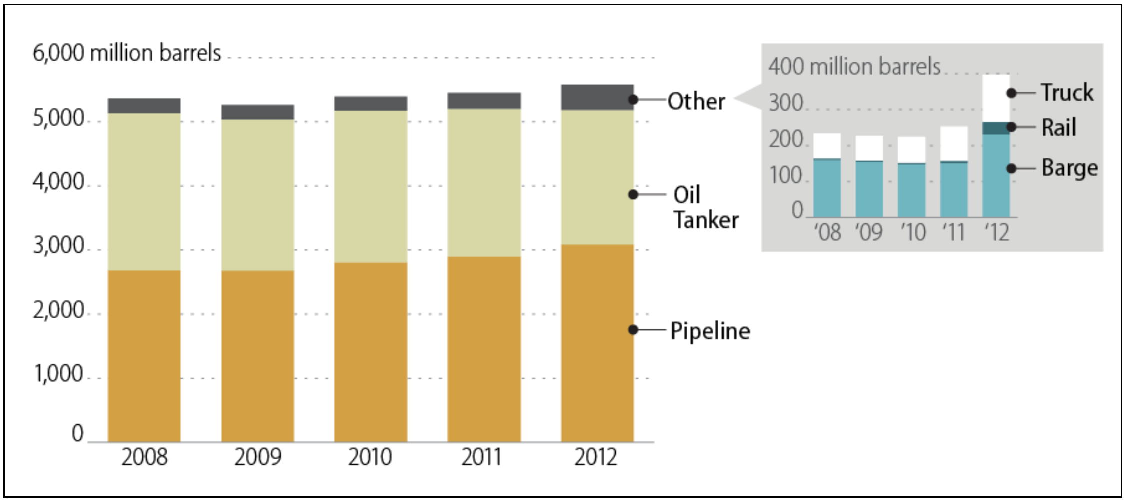
Note: PADD = Petroleum Administration for Defense Districts, five districts established by executive order during World War II for gasoline rationing.

The last entirely new petroleum refinery in the United States opened in 1976. The number of refineries in operation has steadily declined since then as refining capacity has become concentrated in ever larger refineries. A quarter of U.S. capacity is concentrated in 11 refineries with capacities exceeding 300,000 bpd. The largest, Shell/Motiva's Baytown, TX, refinery, was recently expanded to 600,000 bpd. Operable U.S. refining capacity has actually increased from 16.5 million to nearly 18 million bpd over the last decade. Refineries representing approximately 75% of domestic capacity (13.3 million bpd) have the ability to process heavy crude oils, but many smaller refineries can process only light to intermediate crude oil.

Each refinery depends upon a certain grade or blend of crude oils to operate efficiently, depending upon its custom-designed processing equipment. A refinery designed to run light crude oil could not switch to heavy crude oil without adding a coking unit, for example. However some refineries that process heavy sour crude could switch to lighter sweet crude by bypassing their coking units, if the economics of doing so are favorable. Until quite recently, the supply of light sweet crude oil was diminishing, but newly available light sweet crudes from North Dakota's Bakken formation are changing refining dynamics in some regions of the United States, especially as refineries seek supplies that cannot be delivered economically by tanker ships or pipelines.

Traditionally, pipelines and oceangoing tankers have delivered the vast majority of crude to U.S. refineries, accounting for approximately 93% of total receipts (in barrels) in 2012. Although other modes of transportation—rail, barge, and truck—have accounted for a relatively minor portion of crude oil shipments, volumes have been rising very rapidly. The volume of crude oil carried by rail increased 423% between 2011 and 2012, and the volume moving by barge, on inland waterways as well as along intracoastal routes, increased by 53%. The volume of crude oil shipped by truck rose 38% between 2011 and 2012. **Figure 2** shows the change in transportation by mode between 2008 and 2012.

Figure 2. U.S. Refinery Receipts of Crude Oil by Mode of Transportation



Source: Prepared by CRS; data from EIA, *Refinery Capacity Report*, Table 9, June 2013.

Notes: Some shipments may involve multiple modes, such as rail to barge. This figure indicates only the mode used for the last leg of such shipments.

Rail is a relatively high-cost method of transporting oil. Although crude oil transportation costs are typically not a major driver of refiner profitability, refiners are typically wary of incurring any costs that are higher than those faced by their competitors, as all refined petroleum products sold in a region tend to command the same price independent of the refinery that produced them.

The Economics of Oil by Rail

In the short run, rapid expansion of oil production in the Bakken—production volumes increased nearly ten-fold between 2005 and 2013[11]—strained the capacity of existing pipelines and of refiners able to process the oil. Finding ready buyers was difficult, resulting in discounted prices compared to other crude oil traded in the U.S. market. With Bakken crude selling for approximately $4 to $28 per barrel less than West Texas Intermediate (WTI) crude, the U.S. reference price for crude grade, refiners found it profitable to utilize the North Dakota oil delivered by rail even though the rail transportation cost is perhaps $5 to $10 per barrel higher than pipeline costs.

Rail has also been critical to development of Canadian oil sands. Although the vast majority of crude oil imports from Canada are delivered via existing pipeline, imports by rail are estimated to have increased from 1.6 million barrels in 2011 to 40 million barrels in 2013. Construction of the

[11] Energy Information Administration crude oil production data, by state, available at http://www.eia.doe.gov.

proposed Keystone XL pipeline could move a significant proportion of these shipments off the rails, as pipeline transportation is likely to cost less per barrel.[12]

For certain refiners, the economics of using rail to transport Bakken oil supplies are even more attractive. In 2012, several refineries in the Philadelphia area were scheduled for closure. The refineries were using imported crudes, largely sourced from West Africa, which sold at a premium to WTI,[13] making their refined products, notably gasoline, uncompetitive against similar products produced by Gulf Coast refineries that used cheaper heavy crudes. By using supplies from the Bakken, these refineries have lowered their costs and have become more competitive. New owners are now investing in the refineries, including installation of high-speed rail unloaders that would allow them to use 230,000 barrels per day of Bakken crude oil by early 2014.[14] These innovations would also reduce the cost of rail transportation per barrel.

The attractiveness of rail transportation of oil may be temporary. Transporting Bakken crude by rail became cost-effective because of the price discounts created by pipeline bottlenecks. If additional oil pipeline capacity were constructed, say from North Dakota to the East Coast market, refiners would likely prefer lower-cost pipeline transportation. And if the refineries could obtain Bakken crude by pipeline, demand would increase, likely reducing or eliminating the current price discount. Without the price discount, Bakken oil would not be competitive in refining when transported by rail. On the other hand, a rising Bakken crude oil price would likely lead to greater drilling activity in the Bakken fields. Given the uncertainty about the future value of the oil and the longevity of the deposits, it is not certain that investors will undertake construction of pipelines from the Bakken fields to the East Coast. In that case, large volumes of crude could be transported by rail well into the future.

Railroads are a viable alternative to pipeline transportation largely because they offer greater flexibility. The nation's railroad network is more geographically extensive than the oil pipeline network, and better able to ship crude oil from new areas of production to North American refineries. While there are about 57,000 miles of crude oil pipeline in the United States, there are nearly 140,000 miles of railroad.[15]

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[12] For more information about the Keystone XL pipeline, see CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by Paul W. Parfomak et al.

[13] Energy Information Administration price data available at http://www.eia.doe.gov.

[14] Matthew Phillips, "North Dakota's Bakken Oil Finally Hits the East Coast," *Bloomberg Businessweek*, February 6, 2013.

[15] Pipeline data from PHMSA, railroad mileage from Association of American Railroads (includes shortline rail mileage, does not include parallel trackage).

The U.S. Railroad Industry in Brief

The U.S. rail network comprises seven large (Class I) railroads, which focus on moving products between North American regions. These railroads generally market to large volume, long-distance shippers. There are also roughly 500 "shortline" (Class II or III) railroads that sometimes serve as the first or final leg of a Class I rail shipment. Shortlines were often spun-off from Class I railroads because of insufficient business over the line. Class I railroads account for about 70% of system mileage, 90% of railroad employees, and about 95% of freight railroad revenue. Since crude oil movements involve non-traditional rail origins (drilling sites) and destinations (refineries), shortlines are often involved in these movements.

Railroad track is categorized into classes that determine the allowable speeds over the track.[16] Most track with the lowest speed limits is the property of shortlines. If track needs maintenance work, a railroad will issue a "slow order" on that section of track, reducing train speeds. Class I railroads have transitioned to using bigger and heavier cars, raising the maximum weight on many track sections from 263,000 lbs. to 286,000 lbs. Shortline railroads that interchange traffic with Class I railroads have had to improve their roadbeds to accommodate the heavier cars.

The railroad industry, since 1980, is mostly economically deregulated. The Surface Transportation Board can review the reasonableness of railroad rates and service in situations where the railroad is determined to have "market dominance," generally where a shipper is served by only one railroad and cannot ship economically by other means. As "common carriers," railroads are required to provide rail service upon reasonable request. Railroads do not require a special federal permit to transport crude oil. Federal railroad law preempts state and local authority, which is generally restricted to a state or local government's "police powers."

The geographic flexibility of the railroad network compared to the oil pipeline network can be especially beneficial for a domestic market in flux. Railroads can increase capacity relatively cheaply and quickly by upgrading tracks and roadbeds to accommodate higher train speeds, building passing sidings or parallel tracks, increasing the frequency of switchovers from one track to the other, and upgrading signal systems to reduce the headway needed between trains. Although railroads need approval from the federal Surface Transportation Board (STB) to build new lines, they do not require STB approval to make improvements to existing lines. And even without capacity improvements, railroads can offer routings not served by pipelines.

A significant fall-off in railroad coal movements has increased railroads' capacity to transport oil over some routes. In 2013, railroads carried about 395,000 more tank cars of crude than in 2005, but about 1.3 million fewer cars of coal. To put the increase in crude traffic in perspective, crude oil represented less than 1% of total rail carloads in 2012. In the first three quarters of 2013, crude carloads increased to 1.4% of total rail car loadings.

Railroad transport reportedly costs in the neighborhood of $10 to $15 per barrel compared with $5 per barrel for pipeline. In return, railroads offer oil producers certain advantages. Heated railroad tank cars improve the viscosity of oil sands crude so that less diluent needs to be added than if the product were being moved by pipeline. Generally, railroads are more willing to enter into shorter-term contracts with shippers than pipelines (one to two years versus 10 to 15 years), offering more flexibility in a rapidly changing oil market. Moving oil by train from North Dakota to the Gulf Coast or Atlantic Coast requires about five to seven days' transit, versus about 40 days for oil moving by pipeline, reducing producers' need for working capital to cover the cost of oil in transit.[17]

[16] See 49 C.F.R. §213.9.

[17] BB&T Capital Markets, "Examining The Crude By Barge Opportunity," June 10, 2013, p. 15.

Crude oil often moves by unit train, a train that carries just one type of cargo in a single type of car and serving a single destination. Unit trains do not need to be switched or shunted in rail yards, saving time and reducing costs, and return to their point of origin as soon as they have been unloaded. A train consisting of 70 to 120 tank cars can carry in the neighborhood of 50,000 to 90,000 barrels of oil, depending on the type of crude.

One hindrance to the expansion of crude-by-rail has been the lack of tank cars and loading and unloading infrastructure. Much of this investment is being made by the oil industry or by rail equipment leasing companies, not railroads. As of summer 2013, manufacturers had more than 60,000 tank cars of all types on order, representing more than two years of production; the number intended for crude oil transport is unknown, but approximately 92,000 existing tank cars can be used to transport crude oil.[18] Rail terminal capacity is expected to increase fourfold from 2012 to 2015.[19] Matching the daily throughput volume of a pipeline requires several trains per day, with each train taking 13 to 24 hours to unload; oil rail terminals therefore require large areas for parallel loop tracks where multiple trains can await unloading.

Pipelines generally provide more reliable service than railroads. Among other differences, rail shipments are more affected by weather. In addition, railroads generally experience peak demand during the fall due to the grain harvest and retailers' holiday shipments. This may cause locomotives and track capacity to be in shorter supply at certain times of the year.

The Role of Barges and Ships in Domestic Crude Transportation

Many refineries traditionally have received crude from overseas and thus are located near the coastline with access to dock facilities. Some are not equipped to receive crude by rail. Hence, some railroads are transferring oil to barges for the last leg of the trip to refineries, especially in the South and Midwest. Locations where railroads transfer crude oil to barges include St. Louis and Hayti, MO; Osceola, AR; Hennepin, IL; Albany, NY; and Anacortes and Vancouver, WA. In addition, crude produced at Eagle Ford, TX, which is located near ports, is being moved along the coast by either barge or ship.

One river barge can hold 10,000 to 30,000 barrels of oil. Two to three river barges are typically tied together in a single tow that carries 20,000 to 90,000 barrels, about the same load as a unit train. Coastal tank barges designed for open seas, known as articulated tug-barges, or ATBs,[20] can hold 50,000 to 185,000 barrels, although newer ATBs can carry as much as 340,000 barrels, comparable to the capacity of coastal tankers. Much larger crude oil tankers are used to move Alaska oil to West Coast refineries.

[18] "Freight Car Market Headed for New Growth in 2014," *Railway Age*, July 29, 2013.

[19] E. Russell Braziel, RBN Energy Inc. presentation at CSIS conference, *North American Oil and Gas Infrastructure, Shale Changes Everything*," November 14, 2013.

[20] The bow of the tug fits into a notch in the stern of the barge and the tug is hinged to the barge on both sides of its hull, allowing fore and aft (pitch) movement, such as over sea swells.

The Jones Act

The Jones Act may have a profound impact on where crude oil is sourced and how it is transported. The Jones Act requires that vessels transporting cargo between two U.S. points be built in the United States, as well as crewed and at least 75% owned by U.S. citizens.[21] The domestic build requirement for tanker ships, in particular, has been identified as contributing to higher costs in moving domestic crude oil along the coasts.[22] Domestically built tankers are about four times the price of foreign-built tankers,[23] and there is limited capacity in U.S. shipyards to build them. Much of the existing crude oil tanker fleet was built since 2000 to meet Oil Pollution Act of 1990 (P.L. 101-380) requirements that tankers calling at U.S. ports have double hulls. Two crude carriers are expected to be delivered in 2014 to replace two vessels in Alaska trade.

As of June 2013, the Jones Act-eligible fleet of crude oil tankers consisted of 10 ships, all employed in moving Alaska crude oil to the U.S. West Coast or to a refinery in Alaska.[24] Since annual Alaska oil production has fallen by about 46% over the last decade, the Jones Act crude oil fleet has been in decline. About 30 Jones Act-eligible tankers carry chemicals or refined petroleum products, such as gasoline or jet fuel, but these ships do not readily alternate between carrying dirty oil (crude oil, residual fuel oil, asphalt) and refined (clean) petroleum products because the tanks would have to be extensively washed after carrying dirty product, a time-consuming and costly process. Some product vessels have fundamentally different designs from crude carriers and would require a layup in a shipyard to be converted to move crude oil.

In the past, Jones Act tanker shipping rates have generally been higher than, but have largely moved in tandem with, the rates for tankers coming from overseas. Phillips 66 recently chartered two Jones Act tankers to move crude oil from Eagle Ford, TX, to a refinery in Linden, NJ,[25] but it remains to be seen whether other refiners will deem tankers cost-competitive with trains and barges in moving crude oil from the Gulf Coast to the Northeast.

The Role of Tank Trucks

Tank trucks operating on U.S. roadways have been an important link in moving crude oil from domestic drilling sites to pipelines and rail terminals. A typical tank truck can hold 200 to 250 barrels of crude oil. Trucks readily serve the need for gathering product, as the hydraulic fracturing method of drilling employed in tight oil production involves multiple drilling sites in an area and the location of active wells is constantly in flux. A large volume of crude oil is being transported by truck between production areas and refineries in Texas because of the close proximity of the two.

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[21] The law is codified at chapters 81, 121, and 551 of Title 46, United States Code.

[22] See for instance, "Oil and the Ghost of 1920," *Wall Street Journal*, September 13, 2012; Senate Committee on Energy and Natural Resources, Testimony of Faisel Khan, Managing Director, Integrated Oil and Gas Research, Citigroup. Hearing to Explore the Effects of Ongoing Changes in Domestic Oil Production, Refining and Distribution on U.S. Gasoline and Fuel Prices, July 16, 2013.

[23] U.S. Maritime Administration, Title XI Ship Financing Guarantees, Pending and Approved Loan Applications; American Petroleum Tankers S-1 SEC Filing; RS Platou Economic Research, annual and monthly reports; press releases from Teekay Tankers, Scorpio Tankers, and Euronav.

[24] U.S. Maritime Administration, U.S. Flag Privately Owned Merchant Fleet, Oceangoing Self-propelled Vessels.

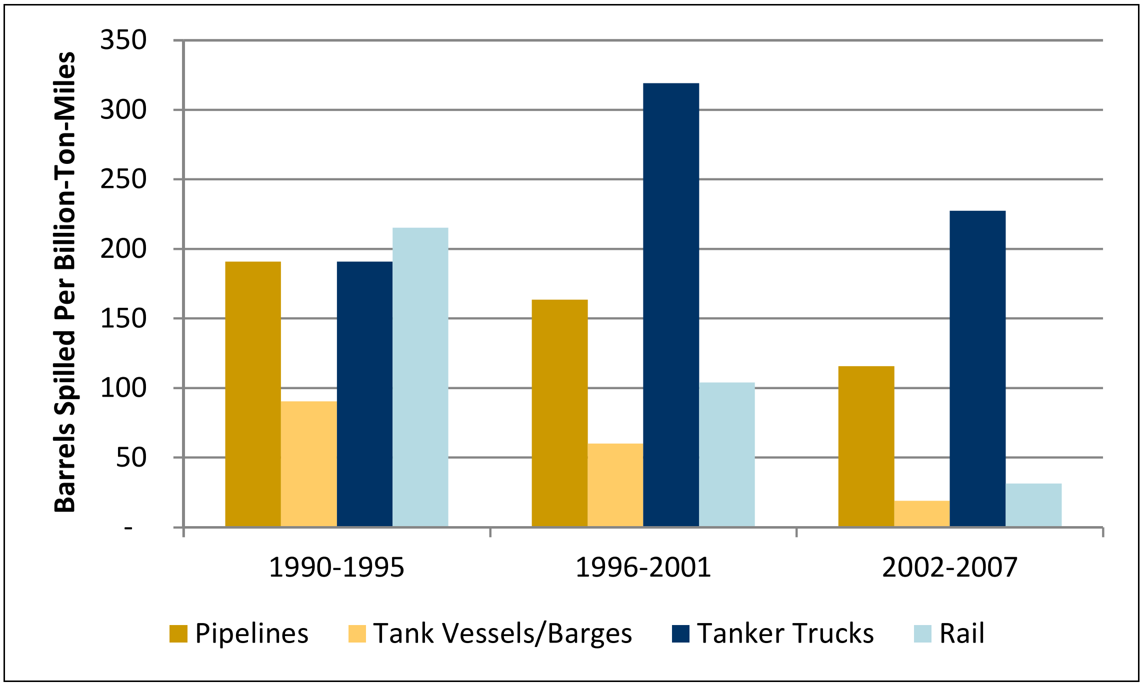
[25] "Phillips 66 Charters Tankers To Bring Shale Oil To Bayway," *Argus Media*, December 13, 2012.

Oil Spill Concerns

Each mode of oil transportation—pipelines, vessels, rail, and tanker trucks—involve some risk of oil spills. Over the period 1996-2007, railroads consistently spilled less crude oil per ton-mile than trucks or pipelines. Barges and domestic tanker ships have much lower spillage rates than trains (**Figure 3**). However, the data in **Figure 3** precede the recent dramatic increase in oil transportation by rail.

Figure 3. Oil Spill Volume per Billion-Ton-Miles

Crude Oil and Petroleum Products during Domestic Transportation



Source: Prepared by CRS; oil spill volume data from Dagmar Etkin, *Analysis of U.S. Oil Spillage*, API Publication 356, August 2009; ton-mile data from Association of Oil Pipelines, *Report on Shifts in Petroleum Transportation: 1990-2009*, February 2012.

Notes: Pipelines include onshore and offshore pipelines. The time periods were chosen based on the available annual data for both spill volume and ton-miles. The values for each time period are averages of annual data for each six-year period.

Given the comparatively small capacity of a rail tank car, around 700 barrels, the total amount spilled from even a major derailment is likely to be small compared to the 260,000 barrels discharged in the 1989 grounding of the *Exxon Valdez* in Prince William Sound, AK, or the approximately 40,000 barrels discharged in the largest U.S. pipeline oil spill CRS can document, which occurred in 1991 near Grand Rapids, MN.[26] Nonetheless, spill volume is arguably a

[26] Sources consulted include NOAA, Oil Spill Case Histories, 1967-1991, Summaries of Significant U.S. and International Spills, 1992; U.S. Coast Guard, Notable Spills in U.S. Waters, Calendar Years 1989-2008, 2009; Dagmar Etkin, Analysis of U.S. Oil Spillage, API Publication 356, August 2009; NOAA, Incident News, at http://incidentnews.gov; EPA, Enforcement and Compliance History Online (ECHO), at http://www.epa-echo.gov/echo/index.html.

relatively unimportant factor in terms of impacts and cleanup costs. Location matters more: a major spill away from shore will likely cost considerably less to abate than a minor spill in a populated location or sensitive ecosystem. Depending on timing and location, even a small spill can cause significant harm to individual organisms and entire populations.[27]

CRS is not aware of any database that tracks oil spills from rail transport. Although spillage per ton-mile of oil transported by rail declined over time, a recent series of major accidents (**text box**) has heightened concern about the risks involved in shipping crude by rail.

Oil by Rail Derailments in 2013 and 2014

Lac Mégantic, Quebec—On July 5, 2013, a train with 72 loaded tank cars of crude oil from North Dakota moving from Montreal, Quebec, to St. John, New Brunswick stopped at Nantes, Quebec, at 11:00 pm. The operator and sole railroad employee aboard the train secured it and departed, leaving the train on shortline track with a descending grade of about 1.2%. At about 1:00 AM, it appears the train began rolling down the descending grade toward the town of Lac-Mégantic, about 30 miles from the U.S. border. Near the center of town, 63 tank cars derailed, resulting in multiple explosions and subsequent fires. There were 47 fatalities and extensive damage to the town. 2,000 people were evacuated. The initial determination was that the braking force applied to the train was insufficient to hold it on the 1.2% grade and that the crude oil released was more volatile than expected.

Gainford, Alberta—On October 19, 2013, nine tank cars of propane and four tank cars of crude oil from Canada derailed as a Canadian National train was entering a siding at 22 miles per hour. About 100 residents were evacuated. Three of the propane cars burned, but the tank cars carrying oil were pushed away and did not burn. No one was injured or killed. The cause of the derailment is under investigation.

Aliceville, Alabama—On November 8, 2013, a train hauling 90 cars of crude oil from North Dakota to a refinery near Mobile, AL, derailed on a section of track through a wetland near Aliceville, AL. Thirty tank cars derailed and some dozen of these burned. No one was injured or killed. The derailment occurred on a shortline railroad's track that had been inspected a few days earlier. The train was travelling under the speed limit for this track. The cause of the derailment is under investigation.

Casselton, North Dakota—On December 30, 2013, an eastbound BNSF Railway train hauling 106 tank cars of crude oil struck a westbound train carrying grain that shortly before had derailed onto the eastbound track. Some 34 cars from both trains derailed, including 20 cars carrying crude, which exploded and burned for over 24 hours. About 1,400 residents of Casselton were evacuated but no injuries were reported. The cause of the derailments and subsequent fire is under investigation.

Plaster Rock, New Brunswick—On January 7, 2014, 17 cars of a mixed train hauling crude oil, propane, and other goods derailed likely due to a sudden wheel or axle failure. Five tank cars carrying crude oil caught fire and exploded. The train reportedly was delivering crude from Manitoba and Alberta to the Irving Oil refinery in Saint John, New Brunswick. About 45 homes were evacuated but no injuries were reported.

Philadelphia, Pennsylvania—On January 20, 2014, seven cars of a 101-car CSX train, including six carrying crude oil, derailed on a bridge over the Schuylkill River. No injuries and no leakage were reported, but press photographs showed two cars, one a tanker, leaning over the river.

In March and April 2013, there were two derailments of Canadian Pacific trains, one in western Minnesota and the other in Ontario, Canada; less than a tank car of oil leaked in each derailment and neither incident caused a fire.

The increasing deployment of unit trains changes the risks involved in shipping oil by rail in two ways. Unit trains of crude oil concentrate a large amount of potentially environmentally harmful and flammable material, increasing the probability that, should an accident occur, large fires and explosions could result. This risk is similar to that of unit trains carrying ethanol, and maybe

[27] National Research Council, *Oil in the Sea III: Inputs, Fates, and Effects* (Washington, DC: National Academies of Science, February 2003).

greater than that of mixed freight trains in which various hazardous materials, such as explosives and toxic-by-inhalation materials, are sequenced among other cars according to federal regulations.[28] On the other hand, while unit trains concentrate a voluminous quantity of potentially dangerous material, they may offer safety benefits from avoiding the decoupling and re-coupling of cars in rail yards, which involve high-impact forces and introduce opportunity for human error.

Special Concerns About Canadian Dilbit

Oil companies generate substantial quantities of crude oil and related substances from the natural bitumen in oil sands, particularly deposits in Alberta, Canada. In 2012, the United States imported 438 million barrels of oil sands-derived crude oils, 125% more than in 2005.[29] Because bitumen is highly viscous, it is transported mostly in the form of diluted bitumen, or dilbit, containing naptha or other materials that make it flow more easily.

Some commenters have argued that due to its physical characteristics, dilbit presents greater risks of oil spills than conventional crude, with potentially greater impacts to the environment.[30] Other stakeholders and organizations have questioned these conclusions.[31] A study released by the National Research Council in 2013, conducted at the direction of Congress,[32] found that the characteristics of dilbit do not increase the likelihood of spills.[33] The extent to which these findings are applicable to rail transport of crude is open to debate, as rail tanker cars may have different operating parameters (e.g., temperature) and physical standards (e.g., wall thickness), or may transport different forms of oil sands-derived crude oil, decreasing the relevance of the NRC findings.

However, observations in the aftermath of a 2010 pipeline spill are consistent with the assertion that dilbit may pose different hazards, and possibly different risks, than other forms of crude oil. On July 26, 2010, a pipeline owned by Enbridge Inc. released approximately 850,000 gallons of dilbit into Talmadge Creek, a waterway that flows into the Kalamazoo River in Michigan.[34] Three years after the spill, response activities continued,[35] because, according to EPA, the oil sands crude "will not appreciably biodegrade."[36] The dilbit sank to the river bottom, where it mixed

[28] These requirements are codified at 49 CFR §174.85.

[29] Data from Canada's National Energy Board. See also CRS Report R43128, *Oil Sands and the Oil Spill Liability Trust Fund: The Definition of "Oil" and Related Issues for Congress*, by Jonathan L. Ramseur.

[30] The primary vehicle for these arguments was a 2011 report from several environmental groups. See Anthony Swift et al., *Tar Sands Pipelines Safety Risks*, Joint Report by Natural Resources Defense Council, National Wildlife Federation, Pipeline Safety Trust, and Sierra Club, February 2011.

[31] See e.g., Crude Quality Inc., *Report regarding the U.S. Department of State Supplementary Draft Environmental Impact Statement*, May 2011; and Energy Resources Conservation Board, Press Release, "ERCB Addresses Statements in Natural Resources Defense Council Pipeline Safety Report," February 2011.

[32] P.L. 112-90, §16.

[33] National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 2013.

[34] National Transportation Safety Board, *Accident Report: Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release- Marshall, Michigan, July 25, 2010*, July 2012, at http://www.ntsb.gov/.

[35] For more up-to-date information, see EPA's Enbridge oil spill website at http://www.epa.gov/enbridgespill/index.html.

[36] Letter from Cynthia Giles, Environmental Protection Agency, to U.S. Department of State, April 22, 2013.

with sediment, and EPA has ordered Enbridge to dredge the river to remove the oiled sediment.[37] As a result of this order, Enbridge estimated in September 2013 its response costs would be approximately $1.035 billion,[38] which is substantially higher than the average cost of cleaning up a similar amount of conventional oil.[39]

Special Concerns About Bakken Crude

The properties of Bakken shale oil are highly variable, even within the same oil field. In general, however, Bakken crude oil is much more volatile than other types of crude.[40] Its higher volatility may have important safety implications.

In January 2014, the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation (DOT) issued a safety alert warning that recent derailments and resulting fires indicate that crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.[41] PHMSA, whose rules are enforced by the Federal Railroad Administration with respect to railroads, reinforced the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. Under its initiative "Operation Classification," PHMSA is to continue to collect samples and measure the characteristics of Bakken crude as well as oil from other locations.

Federal Oversight of Oil Transport by Rail

The Federal Railroad Administration (FRA) has jurisdiction over railroad safety. It has about 400 federal inspectors throughout the country and also utilizes state railroad safety inspectors. State inspectors predominantly enforce federal requirements because federal rail safety law preempts state law, and federal law is pervasive. The FRA uses past incident data to determine where its inspection activity should be targeted, although the FRA Administrator recently stated that in light of the growth of crude-by-rail transportation, the agency also must look for "pockets of risk."[42] FRA regulations cover the safety of track, grade crossings, rail equipment, operating practices, and movement of hazardous materials (hazmat). The Pipeline and Hazardous Materials Safety

[37] EPA Removal Order, March 14, 2013, at http://www.epa.gov/enbridgespill/ar/enbridge-AR-1720.pdf.

[38] See Enbridge Inc., Third Quarter Financial Report, 2013, at http://enbridge.com/InvestorRelations/FinancialInformation/InvestorDocumentsandFilings.aspx.

[39] Based on cost estimates prepared in 2004. See Dagmar Etkin, *Modeling Oil Spill Response and Damages Costs*, Proceedings of the 5th Biennial Freshwater Spills Symposium, 2004, at http://www.environmental-research.com.

[40] Bryden, K. J., Grace Catalysts Technologies, Columbia, Maryland; Habib Jr., E. T., Grace Catalysts Technologies, Columbia, Maryland; Topete, O. A., Grace Catalysts Technologies, Houston, Texas, Processing shale oils in FCC: Challenges and opportunities 09.01.2013 http://www.hydrocarbonprocessing.com/Article/3250397/Processing-shale-oils-in-FCC-Challenges-and-opportunities.html.

[41] Pipeline and Hazardous Materials Safety Administration, Safety Alert—January 2, 2014, Preliminary Guidance from OPERATION CLASSIFICATION. This advisory is a follow-up to the PHMSA and Federal Railroad Administration (FRA) joint safety advisory published November 20, 2013 [78 FR 69745].

[42] FRA Administrator Szabo, Opening Remarks to RSAC Meeting, October. 31, 2013; http://www.fra.dot.gov/eLib/Details/L04852.

Administration within DOT (PHMSA) issues requirements for the safe transport of hazmat by all modes of transportation, which the FRA enforces with respect to railroads.[43]

Rail incidents are investigated by the National Transportation Safety Board (NTSB), an independent federal agency. The NTSB makes recommendations toward preventing future incidents based on its findings. Unlike the FRA, the NTSB is not required to weigh the costs against the benefits when considering additional safety measures and it has no regulatory authority. Many of the NTSB's recommendations concerning oil transport by rail are identical to those it previously issued for transporting ethanol by rail. While the FRA has largely agreed with NTSB's recommendations, its rulemaking process involves consultation with industry advisory committees, and it must determine which of the many rail safety measures under evaluation deserve priority. Implementing a change in FRA regulations can take years.

U.S. safety requirements apply to any train operating in the United States, regardless of its origin or destination. Canadian safety regulations are very similar but do not exactly mirror U.S. requirements. Cross-border shipments must meet the requirements of both countries. Safety standards established by the rail industry, which often exceed government requirements, apply to both U.S. and Canadian railroads.

When a rail incident results in the release of oil, state, territorial, or local officials are typically the first government representatives to arrive at the scene and initiate immediate safety measures to protect the public. The National Oil and Hazardous Substances Pollution Contingency Plan, often referred to as the National Contingency Plan (NCP), indicates that state, territorial, or local officials may be responsible for conducting evacuations of affected populations. These first responders also may notify the National Response Center to elevate an incident for federal involvement, at which point the coordinating framework of the NCP would be applied.

Unlike most federal emergency response plans, which are administrative mechanisms, the NCP is codified in federal regulation and is binding and enforceable.[44] The NCP regulations apply to applicable spills from vessels, pipelines, onshore facilities, and offshore facilities. The definition of "onshore facility" includes, but is not limited to "motor vehicles and rolling stock."[45]

If an oil discharge affects navigable waterways, shorelines, or "natural resources belonging to, appertaining to, or under the exclusive management authority of the United States,"[46] Section 311 of the Clean Water Act, as amended by the Oil Pollution Act of 1990, Section 311(c), provides explicit federal authority to respond.[47] The term "discharge" is defined broadly and is not linked

[43] FRA and PHMSA are agencies within DOT, which has the emergency authority to restrict or prohibit transportation that poses a hazard of death, personal injury, or significant harm to the environment. See 49 U.S.C. §20104.

[44] 40 C.F.R. Part 112.

[45] 40 C.F.R. §300.5. This definition is also found in the Clean Water Act and OPA.

[46] The Oil Pollution Act of 1990 expanded and clarified the President's authorities under Section 311 of the Clean Water Act (33 U.S.C. §2701 et. seq.). For a more in-depth discussion of the Oil Pollution Act, see CRS Report RL33705, *Oil Spills in U.S. Coastal Waters: Background and Governance*, by Jonathan L. Ramseur.

[47] 33 U.S.C. §1321. In addition, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 expanded the authorities of the President to respond to releases of hazardous substances into the environment more broadly than CWA Section 311. See CRS Report R41039, *Comprehensive Environmental Response, Compensation, and Liability Act: A Summary of Superfund Cleanup Authorities and Related Provisions of the Act*, by David M. Bearden. For further details, see CRS Report R43251, *Oil and Chemical Spills: Federal Emergency Response Framework*, by David M. Bearden and Jonathan L. Ramseur.

to specific sources of oil. The President has the authority to perform cleanup immediately using federal resources, monitor the response efforts of the spiller, or direct the spiller's cleanup activities.[48] Several executive orders have delegated the President's response authority to the Environmental Protection Agency (EPA) within the "inland zone" and to the U.S. Coast Guard within the coastal zone, unless the two agencies agree otherwise.[49] The lead federal agency serves as the On-Scene Coordinator to direct the federal resources used in a federal response.

Regulations require that railroads have either a so-called "basic" response plan or a more "comprehensive" response plan, depending on the volume capacity of the rail car transporting the oil.[50] Comprehensive plans are subject to FRA approval, and must ensure by contract or other means that personnel and equipment are able to handle a worst-case discharge.[51] However, the regulatory threshold for the comprehensive response plan is a tank car holding more than 1,000 barrels, so does not apply to the DOT-111 tank cars used today, which hold around 700 barrels of oil apiece. For these smaller tank cars, railroads must prepare only "basic" response plans, which are not subject to FRA approval.

This threshold was established in 1996,[52] before the advent of oil unit trains, each of which may transport, in aggregate, approximately 70,000 barrels (almost 3 million gallons) of oil. The NTSB recently recommended that the threshold for comprehensive plans be lowered to take into account the use of unit trains.[53]

Issues for Congress

While oil by rail has demonstrated benefits with respect to the efficient movement of oil from producing regions to market hubs, the dramatic increase in oil by rail shipments has generated interest in several related issues. These include railroad safety,[54] environmental concerns, and trade-offs over rail versus pipeline development.

Railroad Safety and Incident Response

Prior to the Lac Mégantic derailment, the FRA had increased its inspection activity with regard to trains carrying crude oil. After the derailment, the FRA and PHMSA (along with Transport Canada) initiated a comprehensive review of safety requirements.[55] Three areas of active discussion involve tank car design, prevention of derailments, and railroad operations. On January 16, 2014 U.S. DOT officials met with railroads and oil shippers and announced that

[48] 33 U.S.C. §1321(c).

[49] Executive Order 12777, "Implementation of Section 311 of the Federal Water Pollution Control Act of October 18, 1972, as amended, and the Oil Pollution Act of 1990," 56 *Federal Register* 54757, October 22, 1991.

[50] 49 C.F.R. Part 130.

[51] See 49 C.F.R. §130.31(a) with 49 C.F.R. §130.31(b).

[52] 61 *Federal Register* 30541 (June 17, 1996).

[53] NTSB, Safety Recommendation R-14-4 through -6, directed to PHMSA, January 21, 2014.

[54] For instance, see letter from Senators Rockefeller and Wyden to U.S. DOT and DOE dated January 9, 2014.

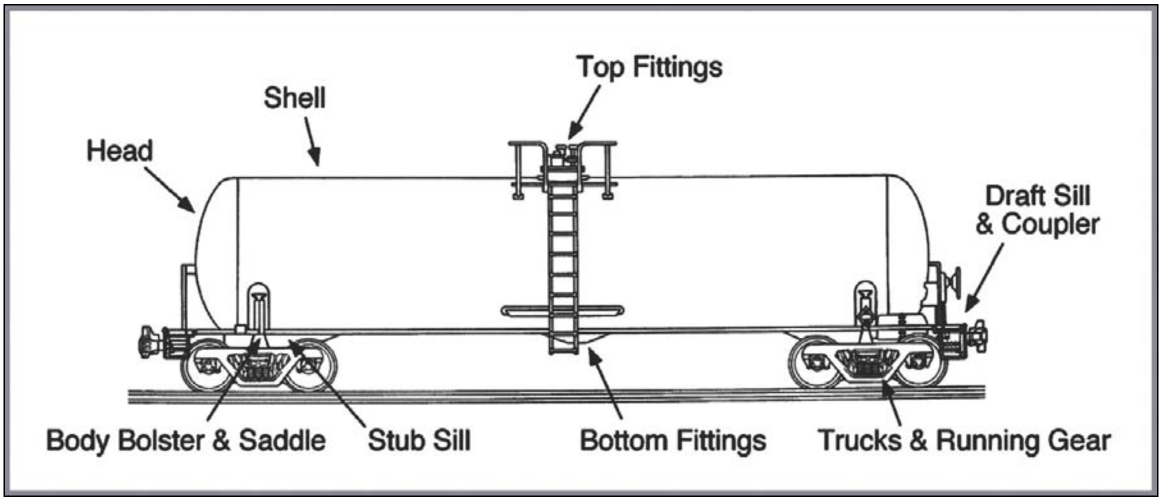
[55] See FRA's Emergency Order No. 28 (78 *Federal Register* 48218), the agencies' Joint Safety Advisory published August 7, 2013 (78 *Federal Register* 48224), referral of safety issues to FRA's Railroad Safety Advisory Committee (78 *Federal Register* 48931), and a NPRM related to rail hazmat (78 *Federal Register* 54849).

within 30 days the industry would submit a plan to improve oil-by-rail safety covering trains speeds, routing protocols, and tank car design.[56]

Tank Car Safety Design

DOT establishes construction standards for tank cars.[57] A tank car used for oil transport is roughly 60 feet long, about 11 feet wide, and 16 feet high (see **Figure 4**). It weighs 80,000 pounds empty and 286,000 pounds when full. It can hold about 30,000 gallons or 715 barrels of oil, depending on the oil's density. The tank is made of steel plate, 7/16 of an inch thick (see 49 CFR §179.201).[58] An oil tank car is typically loaded from the top valve and unloaded from the bottom valve. Loading or unloading each car may take several hours, but multiple cars in a train can be loaded or unloaded simultaneously.

Figure 4. Non-jacketed, Non-pressure Tank Car



In some incidents, oil has been released from the ends of tank cars because the coupler from a neighboring car has punctured the tank during derailment. Valves at the top and bottom of the cars have also been sheared off or otherwise opened during derailment. Efforts to improve crashworthiness have focused on reinforcing the shells of tank cars at both ends or adding protective shields ("jackets"), modifying couplers to prevent decoupling, adding skid protection or diversion shields to protruding valves, eliminating or modifying bottom valves, and increasing insulation for fire protection.[59]

The FRA and PHMSA have questioned whether Bakken crude oil, given its characteristics, would more properly be carried in tank cars that have additional safety features, such as those found on pressurized tank cars used for hauling explosive liquids.[60] Some of these features add weight to

[56] "Rail, Oil Industries to Make Safety Changes for Transporting Crude," *Wall Street Journal*, January 16, 2014.

[57] The tank cars used to transport crude oil fall under DOT specification 111. See 49 C.F.R. §179.

[58] 49 C.F.R. §179.201.

[59] For a discussion of NTSB's recommendations concerning DOT-111 tank cars, in reference to the derailment of an ethanol unit train in Cherry Valley, IL, see NTSB Safety Recommendation R-12-5 through -8, March 2, 2012.

[60] Pressurized tank cars (DOT specification 105 and 112) have thicker shells and heads, metal jackets, strong protective (continued...)

the car, thus possibly increasing the number of shipments needed to move a given amount of product. The railroad industry established additional standards in October 2011 for newly built cars that address some but not all of the safety features that FRA and PHMSA are considering.

Rail cars have an economic life of 30 to 40 years, so conversion of the fleet to a new car standard could take some time. DOT has asked for further information on the costs and benefits of retrofitting the existing fleet.[61] In November 2013, the Association of American Railroads stated it supports either retrofitting or phasing out oil tank cars built before October 2011 (a fleet of about 78,000 cars) and modifying those built after October 2011 (about 14,000 cars).[62] Some Members of Congress have urged DOT to expedite the rulemaking process concerning new tank car safety requirements.[63]

Preventing Derailments

An analysis of freight train derailments from 2001-2010 on Class I railroads' mainline track found that broken rails or track welds were the leading cause of derailments, by far.[64] These problems caused 670 derailments over the period, while the next leading problem (track geometry defects) caused just over 300 derailments. Broken rails or welds also resulted in more severe incidents, derailing an average of 13 railroad cars instead of 8.6 cars for all other causes. Broken rails or welds accounted for 23% of total cars derailed. A separate study covering the same time period found that track problems were the most important causes of derailments, followed by problems with train equipment.[65]

In the Rail Safety Improvement Act of 2008 (P.L. 110-432, Section 403(a)), Congress requested that the FRA study and consider revising the frequency and methods of track inspection. FRA conducted the study and on January 24, 2014 issued a final rule on improving rail integrity.[66] The new rule requires railroads to achieve a specified track failure rate rather than scheduling inspections based on the calendar or traffic volume. It also allows railroads to maximize use of rail inspection vehicle time by prioritizing remedial action when track defects are detected.

The railroad industry takes a number of extra safety precautions for trains carrying certain amounts and kinds of hazardous materials (referred to as "key" trains).[67] Key trains include unit

(...continued)

housings for top fittings, and no bottom valves.

61 78 FR 54849 - 54861, September 6, 2013.

62 For comments filed on this rulemaking see http://www.regulations.gov and search under docket no. PHMSA-2012-0082.

63 See letter from Senator Schumer to PHMSA and FRA dated July 22, 2013 and news release by Senator Hoeven on January 15, 2013 indicating that a DOT final rule on tank cars would not be issued until after January 2015.

64 T87.6 Task Force Summary Report, pp. 9-11; Xiang Liu, M. Rapik Saat, Christopher P.L. Barkan, "Analysis of Causes of Major Train Derailment and Their Effect on Accident Rates," *Transportation Research Record*, No. 2289, 2012, pp. 154-163.

65 Xiang Liu, M. Rapik Saat, Christopher P.L. Barkan, *Safety Effectiveness of Integrated Risk Reduction Strategies for the Transportation of Hazardous Materials by Rail*, Paper presented at the Transportation Research Board, Annual Meeting 2013, paper no. 13-1811.

66 79 *Federal Register* 4234, January 24, 2014.

67 See http://www.aar.com/cpc-1258%20ot-55-n%208-5-13.pdf.

trains of crude oil. In response to the Lac Mégantic derailment, the industry recently modified the guidelines for key trains to include

- restricting train speeds to less than 50 mph;[68]
- increasing the frequency of track maintenance;
- installing wayside defective equipment detectors, such as "hot box" detectors that detect wheels with faulty bearings, every 40 miles, with specific protocols for conductors when defects are indicated;
- using only track in good enough condition to support speeds of 25 mph or higher.

Reducing train speed can reduce the number of cars that derail as well as the likelihood that product will be released from those tank cars.[69]

Shortline Track

It is often the case that a Class I railroad, prior to turning over the operation of a line to a shortline, did not maintain it to the same standards as its busy mainlines. Shippers using a shortline often do not require higher-speed track because they ship infrequently or because the commodities they ship are not time-sensitive. Thus, shortline track is frequently maintained at a lower standard than Class I railroads' track. The Lac Mégantic, Quebec, and Aliceville, AL, crude oil derailments occurred on shortline track. Members of Congress have been concerned with preserving shortline rail service, reflected in a federal loan program for track rehabilitation and improvement and a tax credit for shortline track maintenance.[70]

Railroad Operations

A number of specific operational issues have been found relevant to railroad safety, in general, or to oil by rail transportation specifically.

Terminal Operations

In September, 2013, the FRA solicited public comment on whether current regulations concerning transfer of crude oil from and to tank cars are adequate considering recent practices at transload facilities. Its request for public comment asked for information about what entity controls trains on loop tracks at rail loading terminals and what procedures have been adopted to prevent unintended movement during loading.[71]

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[68] Current federal regulations (49 CFR §174.86) limit only trains carrying poisonous by inhalation materials (not crude oil) to 50 mph.

[69] Athaphon Kawprasert and Christopher P.L. Barkan, "Effect of Train Speed on Risk Analysis of Transporting Hazardous Materials by Rail," *Transportation Research Record,* No. 2159, 2010, pp. 59-68.

[70] The Railroad Rehabilitation and Improvement Financing (RRIF) program and Section 45G of the tax code.

[71] "FRA/PHMSA Additional Questions for Public Comment," Docket No. FRA-2013-0067-0016, 9/4/2013, http://www.regulations.gov.

Railroad Crew Size

Following the Lac Mégantic disaster, legislation (H.R. 3040) was introduced in Congress to require two-person crews on all trains. In the United States, the FRA does not specify in regulation how many persons must operate a train, but notes that the various tasks required while a train is moving essentially necessitate at least a two-person crew. Most trains operate with an engineer and a conductor, but some shortline railroads may operate trains with a single crew member. The FRA appears to be moving toward a regulation requiring two-person crews while allowing for some exceptions.[72] One potential trade-off is that distraction by a fellow crew member has been found to be a factor in past accidents.

Positive Train Control

Railroads are in the process of implementing positive train control (PTC), a system that is designed to override human error in controlling the speed and movement of trains. Congress required that this system be installed on routes carrying passengers or poison- or toxic-by-inhalation hazardous materials (Section 104 of P.L. 110-432), a requirement that applies to about 60,000 miles of railroad. Current law does not require installation of PTC solely because a track carries crude oil, but the law authorizes the FRA to expand the scope of tracks required to have PTC. PTC is not required on track in or near rail yards. The cost and timeline for implementing PTC are topics of current debate among policymakers and stakeholders.[73]

Route Selection

In the Implementing Recommendations of the 9/11 Commission Act of 2007 (P.L. 110-53, Section 1551), Congress required railroads carrying certain kinds and quantities of potentially dangerous commodities to assess the safest and most secure routes for trains carrying these products and to minimize delays and storage for rail cars containing these products. These requirements currently apply to explosive, toxic-by-inhalation, and radioactive material.[74] Security regulations also require that rail cars containing these commodities not be left unattended when being transferred from one carrier to another or between carrier and shipper.[75] The law resulted from efforts by cities like Washington, DC, and Pittsburgh to ban trains carrying hazardous materials.[76] The FRA may consider whether this routing analysis should also apply to unit trains of crude oil.[77] Such a requirement would be controversial because avoiding large urban areas can increase the length of time such trains are in transit and because smaller towns and rural areas likely have less capability to respond to emergencies than large cities.

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[72] FRA presentation to Railroad Safety Advisory Committee, "Appropriate Train Crew Size Working Group Update," October 31, 2013; https://rsac.fra.dot.gov/meetings/20131031.php.

[73] For further information, see CRS Report R42637, *Positive Train Control (PTC): Overview and Policy Issues*, by John Frittelli.

[74] See 49 C.F.R. §172.820; 73 *Federal Register* 72182, November 26, 2008.

[75] See 49 C.F.R. §1580.107.

[76] *U.S. Rail News*, June 11, 2008, pp. 1-2; "Hazmat Hazards: U.S. Cities may not wait for Washington Before Trying to Reroute their own hazmat trains," *Journal of Commerce*, December 12, 2005.

[77] RSAC meeting, presentation by HAZMAT Working Group, October 31, 2013. The NTSB has recommended this change; see Safety Recommendation R-14-1 through -3, January 23, 2014.

Incident and Oil Spill Response

The increased use of rail for crude oil shipments is likely to increase the number of incidents, some of which may involve oil spills. As described above, the National Oil and Hazardous Substances Contingency Plan provides a framework for federal, state and local collaboration in response to releases of oil and hazardous substances. Considering the relative proximity of rail shipments to population centers, a potential issue for Congress is the safety and adequacy of spill response.

In addition, based on past history, increased frequency or severity of incidents related to shipments of crude oil by rail could lead some local communities to seek additional funding to ensure adequate spill response capabilities, including personnel, training, equipment, and community notification.

The Accuracy of Train Cargo Information

Crude oil may also be carried by "mixed trains"—trains carrying a variety of different commodities. With mixed trains, it is important to first responders that they have an accurate list of which cars contain what commodities (the train "consist"). Often the sequencing of cars changes en route, so the consist information provided by the crew at the scene of an incident may no longer be accurate. Although all vehicles containing hazardous materials must display placards indicating their potential dangerous characteristics (e.g., flammable, corrosive, explosive), responders often need more specific information about the commodities involved in an incident. One potential remedy under consideration is an electronic manifest system that would offer the capability of easier updates. In MAP-21, Congress authorized PHMSA to conduct pilot projects on paperless hazmat information sharing among carriers (of various modes including rail) and first responders.[78] A potential drawback raised by the railroads is that electronic devices at the scene of an incident could encounter technical problems. Another remedy is greater diligence by railroad crew in keeping the paper consist up to date. The NTSB has asked whether a copy of the consist should also be kept at the end of a train in case the copy kept by the crew at the head of the train is lost in an incident.

Rail vs. Pipeline Development

Certain rail routings of crude oil could be replaced by reconfiguring the existing pipeline network and constructing additional pipeline capacity. In general, pipelines could provide safer, less expensive transportation than railroads, assuming that pipeline developers are able to assure markets for the oil they hope to carry.

Pipeline development could be particularly important for shipments of crude oil from Canada to the United States. In light of growing Canadian exports, several proposals have been made to expand the cross-border pipeline infrastructure. Of the five major pipelines currently linking Canadian petroleum producing regions to markets in the United States, two (Alberta Clipper and Keystone) began service in 2010. A permit application for a sixth pipeline, Keystone XL, a very large project which would also transport some Bakken crude, was initially submitted in 2008 and

[78] Section 33005 of P.L. 112-141.

is in the final stages of review by the U.S. Department of State.[79] Keystone XL has been the subject of intense scrutiny and debate by Congress, the Executive Branch, and numerous stakeholders. The Keystone XL review and approval process is highly contested, and the pipeline's approval remains uncertain.

Other proposed oil pipeline projects, such as the reversal of the Portland-Montreal oil pipeline to enable export of Canadian oil via a marine terminal in Maine, are also encountering greater public scrutiny and opposition. On the whole, the barriers to new oil pipeline approval in any jurisdiction seem to have risen significantly since Alberta Clipper and Keystone were completed.

Shipment of oil by rail is, in many cases, an alternative to new pipeline development. This involves tradeoffs in terms of both transportation capacity and safety. In its ongoing review of the Keystone XL pipeline proposal, the State Department has argued that, if the pipeline is not constructed, additional oil-by-rail capacity will be developed instead. As the State Department's 2014 Final Environmental Impact Statement for the Keystone XL project states,

> In the past 2 years, there has been exponential growth in the use of rail to transport crude oil throughout North America, primarily originating from the Bakken in North Dakota and Montana, but also increasingly utilized in other production areas, including the [Western Canadian Sedimentary Basin]. Because of the flexibility of rail delivery points, once loaded onto trains the crude oil could be delivered to refineries, terminals, and/or port facilities throughout North America, including the Gulf Coast area.[80]

Consistent with this view, both Canadian National Railway and Canadian Pacific Railway reportedly have been pursuing a "pipeline on rails" business strategy, including new track investments, to move Canadian crudes to new markets throughout North America.[81] Increasing cross-border movements of crude oil by rail on existing track does not require State Department approval, so such an approach seeks to avoid regulatory delays. While the potential volumes associated with rail transportation of crude could be lower than pipeline volumes, they could still be significant. Some analysts have suggested that oil-by-rail volumes could be large enough to make a major new pipeline project like Keystone XL unnecessary.[82] Similar arguments could apply to other oil transportation corridors within North America.

Others are less certain that oil by rail can substitute so readily for pipeline capacity, as rail expansion would require significant infrastructure development including loading and unloading facilities, track capacity, and, possibly, additional tank car availability. The State Department's analysis finds that under certain conditions, including particular oil and oil transportation prices, "there could be a substantial impact on oil sands production levels."[83] Other market analyses similarly find that in the short and medium term some production could be curtailed.[84]

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[79] The construction, connection, operation, and maintenance of a pipeline connecting the United States with a foreign country require executive permission through a Presidential Permit under Executive Orders 11423 and 13337.

[80] U.S. Department of State, January 2014, Final EIS, Section 5.1, "No Action Alternatives."

[81] Nathan Vanderklippe, "CN, CP Push for a 'Pipeline on Rails,'" *Globe and Mail*, February 7, 2011.

[82] "Keystone Pipeline Seen as Unneeded as More Oil Moves by Rail," *CBC News*, September 10, 2013.

[83] 2014 Final EIS, p. 1.4-8.

[84] For example, Canadian Imperial Bank of Commerce, "Too Much of A Good Thing: A Deep Dive Into The North American Energy Renaissance," August 15, 2012; TD Economics, "Pipeline Expansion is a National Priority," Special Report, December 17, 2012; International Energy Agency," Medium-Term Oil Market Report," May 14, 2013.

Refiner economics may ultimately favor pipelines over rail, although those investment decisions will be determined by market forces. When it comes to safety, however, the federal government plays a major role, and thus may have considerable influence on infrastructure expansion. Some participants in the Keystone XL debate, for example, have asserted that recent oil-by-rail incidents underscore the need for a new pipeline as, in their view, a safer mode of transportation for Canadian crudes,[85] while others insist that safety comparisons between the two transportation modes are less conclusive.[86] On balance, however, it seems likely that policies that raise the cost of transporting oil by rail would increase the attractiveness of pipeline development, and, for that matter, expansion of crude oil transportation by barges, tanker ships, and tanker trucks.

Rail Transport and Crude Oil Exports

The large increase in U.S. oil production has led some Members of Congress to advocate changing the law that generally prohibits exports of crude oil.[87] An increase in crude oil exports would likely require greater use of rail transportation, as the crude oil pipeline network is not oriented to serve export ports. Some environmental groups have stated their opposition to construction of new rail facilities or terminals that would facilitate oil exports, as they believe increased exports will encourage environmentally damaging production in the United States and Canada.[88]

[85] Diana Furchtgott-Roth and Kenneth P. Green, *Intermodal Safety in the Transport of Oil*, Fraser Institute, October 2013, http://www.fraserinstitute.org/uploadedFiles/fraser-ca/Content/research-news/research/publications/intermodal-safety-in-the-transport-of-oil.pdf.

[86] See, for example: Rory Johnston, "Train vs. Pipeline: What's the Safest Way to Transport Oil?" *Christian Science Monitor*, Energy Voices blog, October 22, 2013, http://www.csmonitor.com/Environment/Energy-Voices/2013/1022/Train-vs.-pipeline-What-s-the-safest-way-to-transport-oil.

[87] The Senate Energy and Natural Resources Committee held a hearing on this issue on January 30, 2014.

[88] See, for example, the comments of Sierra Club official Michael Marx in Blake Sobczak, "Environmentalists 'get real creative' to combat oil by rail," Energy Wire, January 13, 2014.

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Oil Spills in Washington State: *A Historical Analysis*

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Cover Photo:
The tank vessel Mobil Oil grounded on Warrior Rock in the Columbia River on March 20, 1984. Rudder failure from improper maintenance was the cause of the accident. After losing 200,000 gallons of heavy oil, this photo shows how other vessels were used in an attempt to lighten and refloat the tanker. *Photo by Jon Neel*

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Introduction

Twenty-two years have elapsed since the Department of Ecology first proposed establishing a comprehensive oil spill prevention and response program in Washington State. The 1975 legislative proposal was prompted after the state suffered major oil spills. Another concern at that time was that the brand new Alyeska pipeline would dramatically increase oil tanker traffic in the Puget Sound. Although the Alaskan pipeline spurred major refining activity in Washington, the proposed environmental protection program never materialized due to lack of funding. Even though no one wanted spills to occur, the full public cost of oil spills was not placed completely on the shoulders of those responsible for transporting oil. The oil spills kept occurring.

It took a series of major oil spills in Washington and Alaska in the late 1980s and early 1990s before Washington's innovative spill prevention and response program was finally put into place by the Legislature. These major spills include:

- The 1985 *ARCO Anchorage* tanker spill in which 239,000 gallons of crude oil was released into marine waters at Port Angeles;
- The 1988 *Nestucca* barge spill which released 231,000 gallons of fuel oil into waters along the coast of Grays Harbor ;
- The disastrous 1989 *Exxon Valdez* spill in Alaska which unleashed 11 million gallons of crude oil into Prince William Sound;
- The 1991 Texaco refinery spill at Anacortes which released 130,000 gallons of crude oil, of which 40,000 gallons went into Fidalgo Bay; and
- The 1991 spill at the U.S. Oil refinery in Tacoma which involved 600,000 gallons of crude oil, most of which was stopped from entering state waters.

How these and other major oil spills accelerated state and federal oil spill prevention, preparedness and response legislation is outlined in **Appendix 2**. This outline shows how the major preventable spills between 1985 and 1992 resulted in innovative legislation which holds potential spillers accountable for preventing and cleaning up spills.

Washington's oil spill prevention and response program has been in place for six years. This report is an examination of the history of oil transportation and the resulting trends in oil spills. This analysis is the first step toward measuring the level of success that industry, government and the public are having on preventing oil spills. This report is also intended to help Washington determine how to best provide the "best achievable protection" from the effects of oil spills while assuring that federal and state programs complement each other.

This report provides partial answers to the following fundamental questions:

- What fundamental forces have shaped state policy regarding oil transportation and spills?
- Has Washington's additional attention to oil spill prevention and response paid off?
- Given Washington's recent increased refinery production, increased pipeline traffic and expanded Pacific Rim trade: How does our state's record of recent spills compare with national and international trends?
- Should the state make any adjustments in its program as a result of these trends?

Chapter 1: Washington State Energy Policy and Oil Spill Initiatives

Washington's unique physical geography coupled with its abundance and diversity of natural resources has been the driving force behind how the state has provided for its energy needs and how much importance the state has placed on preventing and responding to environmental threats, especially oil spills.

Located at the northwest corner of the continental United States, Washington's rugged mountain terrain and distance from traditional energy sources prompted the state to develop its own energy reservoirs. Since the 1930s, Washington has exploited its hydroelectric resources and these dams have, in many ways, become the region's energy backbone.

The Puget Sound is also the closest national port in the lower 48 states for vessels carrying crude oil out of Valdez, Alaska. For more than 25 years, tankers laden with Alaskan crude oil have brought their precious cargo into Washington. Even though the state produces none of its own oil, Washington has the fifth highest refining capacity of any state in the nation. The waters of Washington State are also one of North America's primary water-borne transportation avenues for Pacific Rim commerce. A visitor to one of Washington's busy ports will see many ships flying flags from Russia, China, Japan, Korea, Malaysia and a variety of other nations.

At the same time, Washington's waters and shorelines contain highly sensitive and valuable natural resources. State marine waters contain critical commercial resources including fishing, crabbing, shrimping and shellfish industries. Washington is also blessed with abundant and diverse fish and wildlife resources which are a driving force in state tourism and provide recreational opportunities for residents. The seabird colonies along Washington's outer coast are among the largest in the United States. In addition, 29 species of marine mammals — including whales, dolphins, seals, seal lions and sea otters — breed in or migrate through the state. The Olympic Coast is the least disturbed major section of coastline in the continental lower 48 states and, according to the Office of Marine Safety and U.S. Coast Guard, it is also the area in Washington that is at greatest risk of experiencing a major vessel oil spill.

Given the importance of preventing spills, this report explores the important connection between historical oil spill information and spill trends, and identifies general areas where non-regulatory approaches for spill prevention might be viable. Effective spill prevention can best be attained through the right mix of regulatory and voluntary compliance initiatives. As state regulatory programs have matured, Ecology has been shifting its focus to educational initiatives. The information on spill trends in this report is part of this effort.

Measuring the effectiveness of state spill prevention endeavors is very complex. Most experts agree that while human factors of one type or another underlie most incidents, spills occur from a wide variety of specific sources and causes. Specific technological or procedural changes must be developed and implemented to eliminate or minimize the occurrence of these incidents. If we are to continue making good progress in preventing spills, it is imperative that we gather better information on actual spills to understand these incidents. This report is also an effort to obtain and disseminate this information.

State Oil Spill Policy: A Historical Overview

Prior to the mid-1940s, most Washington communities discharged raw sewage into state water bodies, most industrial wastes went untreated and small oil spills were accepted as part of doing business. As a result of continued population growth, state harbors, rivers, lakes and streams quickly became polluted. In March 1945, the Legislature established the Pollution Control Commission. In order to give the commission real authority, lawmakers also passed legislation prohibiting the pollution of any waters of the state and established specific penalties for violations.

In 1955, the Legislature passed a new law which required that any "commercial or industrial operation of any type which results in the disposal of solid or liquid waste material into the waters of the state shall procure a permit" from the Pollution Control Commission. This state act preceded the federal Water Pollution Control Act by 10 years. In several instances, Washington State environmental laws have been models for federal pollution laws.

Growth of Washington Oil Industry

Prior to 1950, there were no refineries and very little crude oil was transported into Puget Sound. In 1953, the Trans-Mountain Pipeline Company and Mobil Oil announced their plan to construct an oil pipeline from British Columbia into Washington. A year later, the state received its first delivery of Canadian crude oil. Most of Washington’s refineries were constructed in the 1950s, including:

- 1954 — Mobil Oil refinery, Ferndale (now owned by Tosco);
- 1955 — Shell Oil refinery, Anacortes;
- 1957 — US Oil refinery, Tacoma; and
- 1958 — Texaco refinery, Anacortes.

In 1958, a high tariff imposed by Canada on the Trans-Mountain Pipeline resulted in a 12-18 month embargo on oil imports from British Columbia. This and other events led to concerns about the long-term stability of the Canadian supplies. In order to improve the oil transportation system, the Olympic Pipe Line Company built its pipeline in 1966 and began delivering petroleum products from the refineries in the north part of the state to consumers in Seattle, Tacoma and Olympia in Washington, and to Portland and Eugene in Oregon.

Developments Related to Alaskan Oil
In 1968 and 1969, the Alaska North Slope oil fields were discovered at Prudhoe Bay. In anticipation of the movement of Alaskan oil into Washington and other pressing environmental concerns, the Legislature passed a series of environmental and spill-related laws.

In 1970, the Washington State Legislature established the Department of Ecology, followed quickly by the passage of the 1971 Washington Oil Pollution Act which:

- Established unlimited liability for oil spills;
- Provided for state cleanup capability; and
- Specifically clarified that the discharge of any oil into state waters was illegal.

That same year, Governor Dan Evans requested an oil risk analysis report concerning the transportation of oil into Puget Sound. Also in 1971, ARCO built its Cherry Point refinery near Ferndale. This move put state production of petroleum products well ahead of in-state consumption. It also greatly increased tanker traffic into Puget Sound.

Construction of the Trans Alaska Pipeline System (TAPS) began in 1973 after the U.S. Congress passed the Trans Alaska Pipeline Act. However, in October 1973 the Organizations of Petroleum Exporting Countries (OPEC) placed an embargo on oil exports to the United States. The resulting shortage placed additional national attention and reliance on Alaskan North Slope oil.

In Washington, one of the results of the embargo was that in 1975 the Northern Tier Pipeline Company proposed constructing a major oil pipeline originating in Cherry Point near Ferndale and terminating in Minnesota. In January 1976, Northern Tier changed its proposed point of origin from Cherry Point to Port Angeles.

Also in 1975, the Legislature passed the Washington Tanker Safety Act which prohibited tankers exceeding 125,000 dead weight tons from entering Puget Sound, and required tug escorts and pilots for certain other tankers. In 1978, the U.S. Supreme Court invalidated this “supertanker” ban in the case of *ARCO vs. Governor Ray*. The court found that federal law pre-empted Washington from banning large tankers, but affirmed the right of the state to establish tug escort and other requirements. U.S. Senator Warren Magnison later re-established supertanker limits through federal legislation.

In the 1970s, the Department of Ecology completed a number of shoreline sensitivity studies focused on the San Juan Islands in anticipation of the influx of Alaskan oil. The studies were undertaken in order to establish a “baseline” so that any environmental changes precipitated by a major oil spill could be more readily quantified. In both 1972 and 1975, Ecology proposed creating a state spill prevention and response program but could not secure funding from the Legislature for the effort. It took a series of major spills in the late 1980s and early 1990s to provide the impetus to establish and fund a state comprehensive spill prevention, preparedness and response program (see **Appendix 2**).

In June 1976, a federal Coastal Zone Management law placed a partial prohibition on the expansion of existing oil terminals. However, this provision may be superseded by other federal laws. That same year, Washington also established the Energy Facility Site Evaluation Council (EFSEC) whose mission was to oversee the siting and permitting of energy facilities such as pipelines, refineries and nuclear power plants. The council held extensive hearings on the Northern Tier Pipeline proposal. The pipeline project was not approved.

Recent Developments
During the late 1970s, EFSEC certified the siting and construction of five Washington Public Power Supply System (WPPSS) nuclear power plants. Three developments — the subsequent demise of four of these five plants, the WPPSS bond default and the shut down of the federal "N" reactor at the Hanford Nuclear Reservation — assured the state's continued reliance on hydropower and fossil fuel resources, including oil and coal for use in the Centralia power plant.

In 1990, the Trans Mountain Pipeline Company proposed constructing an oil terminal at Low Point east of Port Angeles on the Olympic Peninsula. The proposal included two single-point mooring buoys, a tank farm at Low Point, and a pipeline which would be located under Puget Sound and connect the Low Point facility with refineries located at Anacortes and Ferndale. The project would have eliminated most tanker traffic coming into Puget Sound beyond Port Angeles, but was eventually withdrawn as a result of public environmental concerns and lack of support from the oil industry.

Even with the state's relative isolation from continental U.S. energy supplies, its oil markets are not immune to the market effects of Mideast oil supply volatility as seen during the 1973 OPEC embargo. On Dec. 11, 1996, the United Nations again allowed the sale of Iraqi oil on the international market as a result of humanitarian pressures. This action is expected to lower the consumer price of refined petroleum products throughout the United States.

Current Regulatory Framework

Ecology has been involved in preventing and responding to spills since the agency was formed in 1971. The agency's spill response capability prior to 1989 consisted of a team of employee volunteers in each of the four regional offices whose main area of expertise lay in other program areas. There was little centralized management of spill activities. As a result of the drawbacks associated with this decentralized response system and the identification of additional funding, Ecology centralized the spill organization in 1990.

These changes and the legislation which passed from 1989 to 1992, resulted in the state spill program which continues to evolve to this day with centralized management systems and regional service delivery. Ecology is now responsible for:

- Preventing spills at oil handling facilities;
- Managing the state's preparedness efforts;
- Responding to oil and hazardous material spills statewide; and
- Coordinating state natural resource damage assessment activities.

The U.S. Congress passed the Oil Pollution Act in 1990 (OPA 90). This statute created new national standards for oil spill prevention and response in the wake of the Exxon Valdez spill. Congress delegated responsibility for implementing most of OPA 90's provisions to the Coast Guard, Environmental Protection Agency, Department of Transportation's Office of Pipeline Safety, National Oceanic and Atmospheric Administration and the Minerals Management Service.

The Washington State Office of Marine Safety (OMS) was created in 1991 by the Legislature to provide further assurance that frequency of oil spills would be reduced. OMS is responsible for preventing vessel oil spills through vessel inspections, investigation of marine casualties, enforcement of state maritime standards and by approving vessel spill contingency plans.

State and Federal Relationships

Washington's role in the current state-federal framework for regulating the oil industry is complicated because each major federal regulatory agency views the role of the state differently. Some independent legal analysts believe that the U.S. Coast Guard attempts to promote uniformity by establishing "ceilings" for regulatory requirements, while the U.S. Environmental Protection Agency uses federal environmental laws to set "floors" which allow states to set more stringent requirements if they are necessary for regional considerations. Major oil pipelines are regulated by the U.S. Department of Transportation's Office of Pipeline Safety. This agency generally sets ceilings. However, unlike the EPA and Coast Guard, the Office of Pipeline Safety delegates some of their spill prevention authority to states that have established effective regulatory programs.

Some of these federal agency policy differences concerning state program consistency can be traced to concerns for interstate uniformity regarding transportation systems such as vessels, trucks and airlines. However, these interstate concerns may not be valid when states establish regional standards for fixed facilities and do not impede interstate commerce. Questions remain regarding EPA and the Coast Guard delegation of programs to states and why fixed interstate pipelines should not be subject to state spill prevention standards if interstate commerce is not impeded. These issues are particularly relevant when the current congressional view of states rights' seems to be reducing federal regulatory programs in favor of state control. However, at this time federal law does not provide a mechanism for state delegation.

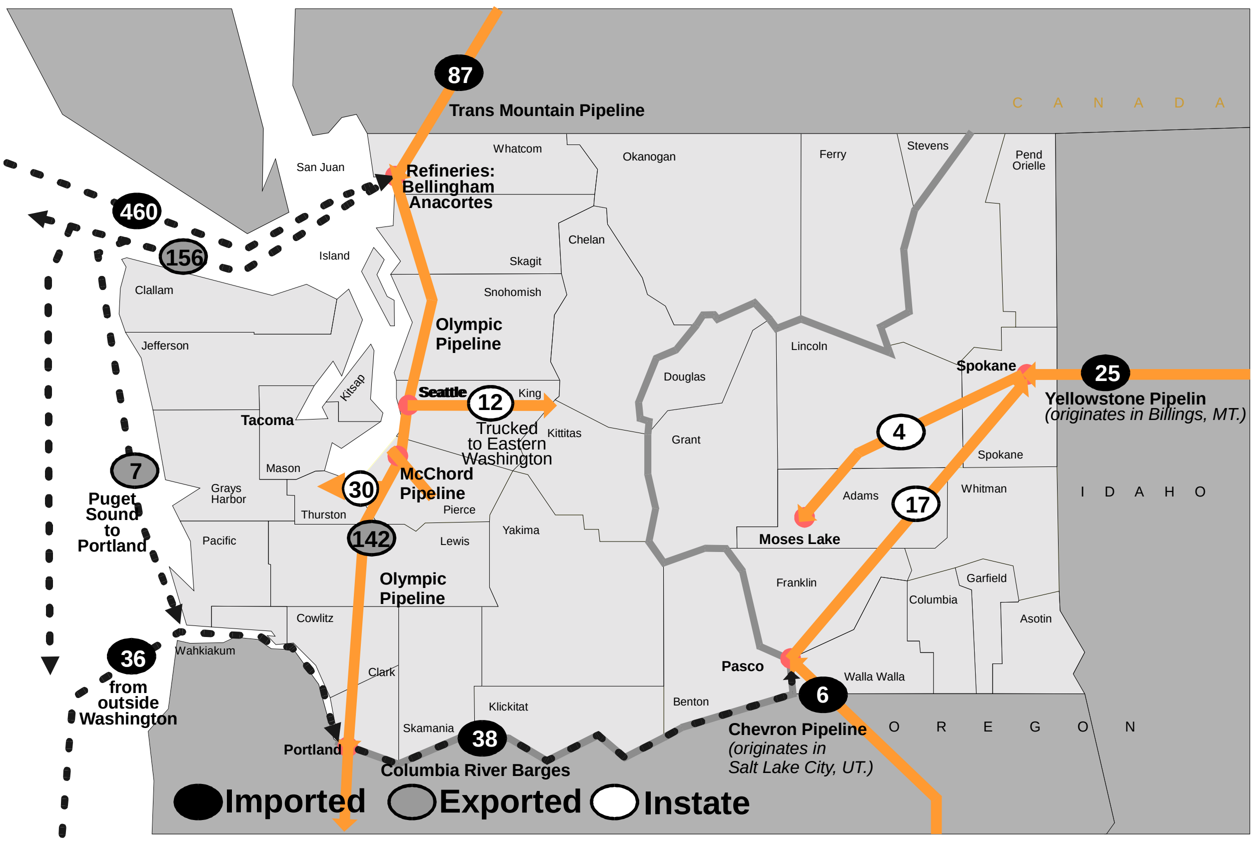
These differences in regulatory approach do not apply to spill preparedness and response. EPA and the Coast Guard have established strong and effective cooperative mechanisms with respect to state co-management of spill responses while minimizing duplication.

Current Oil Transportation Patterns and Related Spill Risks

As one of North America's major gateways to Pacific Rim trade, Puget Sound is one of the busiest waterways in the world with vessel traffic going to several busy ports in Washington State and to major facilities in Vancouver, British Columbia. More vessel tonnage moves through the Strait of Juan de Fuca than through the combined ports of Los Angeles and Long Beach, California.

Washington is also one of the nation's primary petroleum refining centers. Refined products are exported from Washington to other western states, such as Oregon and California, primarily through pipelines, barges and tankers. There are five major pipelines in Washington: Trans Mountain, Olympic, McChord, Chevron and Yellowstone. The primary transportation routes and quantities of oil transported are shown in **Figure 1**. The map shows the enormous quantities of crude oil and refined products which are transported through our coastal areas, Puget Sound and the Columbia River by tankers and barges.

Figure 1 — Oil Movement in Washington State (figures in thousands of barrels a day)



The vessels in-bound to Puget Sound are primarily moving crude oil to Washington's refineries. Large quantities of crude oil also come into our refineries through the Trans Mountain Pipeline. Refined petroleum products are moved to in-state consumers primarily by pipelines and trucks. These transportation corridors constitute the areas at greatest risk of major spills. Significant elements of major spill risk which are not indicated on the map include: cargo and passenger vessels in Pacific Rim trade; large facilities with piping and storage tanks; and rail/tanker truck traffic.

Production in the Alaskan North Slope oil fields has declined over the last few years as the proven reserves are drawn down. However, it is not clear at this time whether this trend will continue, as projected recently by the Oil and Gas Journal, or whether new finds and improved production techniques will stabilize production as believed by some industry analysts. The long-term effect of changes in Alaskan oil production on Washington refineries remains to be seen. One of the current effects of the reduced North Slope oil supply is that oil importation from Canada through the Trans Mountain Pipeline has dramatically increased in recent years. The Office of Marine Safety data indicates that the number of individual tankers moving oil into Washington waters was:

- 907 in 1993;
- 908 in 1994;
- 723 in 1995; and
- 804 in 1996.

This data includes tank ships bound through Washington waters to Puget Sound ports, the Columbia River, Canadian ports and Grays Harbor.

Chapter 2: Oil Spill Data Sources

The spill related information in this report is divided into two sections for the purpose of presenting a clear analysis. ***Chapter 3: Major Oil Spills in Washington*** deals with well documented facility, pipeline, vessel and surface transportation spills greater than 10,000 gallons that have occurred since 1970. ***Chapter 4: Recent Trends in Oil Spills*** takes a closer look at all oil spills between 25 and 10,000 gallons that have occurred in the last four years — with the exception of surface transportation (railroad and truck) spills.

Ecology began consistently keeping records of oil spills only after the Legislature provided dedicated funding for the program in 1991. Prior to this time, readily accessible records are incomplete. Fortunately, the agency has institutional memory and information relating to larger spills, particularly those exceeding 10,000 gallons. In preparing this report, a range of sources were reviewed to fill in data gaps. With respect to recent spills (discussed in **Chapter 4**), the information should be accurate given the careful data collection efforts of Ecology's spill and damage assessment team for spills of over 25 gallons reaching surface waters. Spill information is stored in the agency's Environmental Report Tracking System (ERTS) database and a small "stand alone" database for major spills.

Information on specific spills in this report could contain inaccuracies. For example, there is often a tendency by those responsible for a spill to under report the amount of product spilled. No potential systematic errors in the data have been identified other than the possible under reporting of spill volume. Accurate information on the root cause of past spills was also difficult to obtain. Therefore, a smaller data set was used to evaluate spill causes.

Data for land transportation (truck and rail) spills has not been included in the analyses of recent spills because of a lack of complete information about this industry segment. However, land transportation spills do represent a serious threat. Staff from Ecology's regional office located in Yakima have reported that tanker truck accidents have resulted in multi-thousand gallon spills with some regularity over the years. These tanker truck spills pose a significant threat to public health and safety in addition to environmental damage. These inland fuel spills can contaminate drinking water, create dangerous fumes, pose a fire threat and result in fresh water fish kills.

Unless otherwise noted, the figures in this report do not include information on leaking underground storage tanks (LUST) or from spills of animal or vegetable oil.

Ecology intends to use the information contained in this report as environmental quality indicators to help measure the state's success in preventing spills. The information will also help the agency target its facility spill prevention efforts. The agency will continue tracking and reporting spill information and appreciates receiving additional information regarding spill history and trends from all sources.

Chapter 3: Major Oil Spills in Washington

This section evaluates information on major spills of 10,000 gallons or more which have occurred in Washington since 1970.

Distribution of Major Spills

The historical trends in the annual volume of oil spilled each year from major incidents are a key indicator of the state's success in preventing major spills. According to the *Oil Spill Intelligence Report*, the annual average volume of oil spilled worldwide from oil spills greater than 10,000 gallons during the five year period 1987-91 was 53 million gallons (excluding the 1991 Persian Gulf war related causalities). However, the annual average volume of oil spilled at major oil spills during the four year period 1992-95 was 75 million gallons worldwide — a 41 percent increase.

The "1995 International Oil Spill Statistics" compiled by the *Oil Spill Intelligence Report* concluded that despite the considerable efforts to reduce spills, a downward trend in the number of large spill incidents worldwide "is probably not occurring."

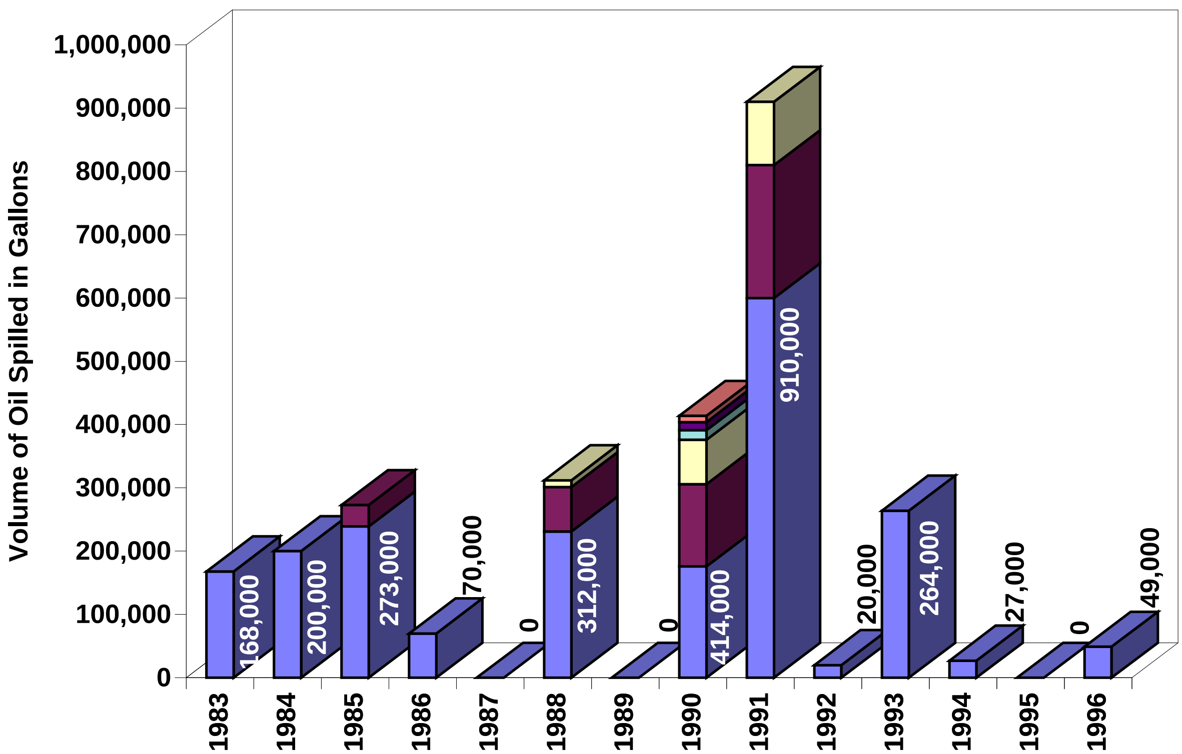
The data in **Figure 2** displays the annual amount of oil spilled in Washington State from spills larger than 10,000 gallons. As seen in this figure, the amount of oil spilled per year as a result of major incidents appears to be declining in Washington during the last five years. Although there is not enough data to evaluate the trends statistically, it does appear that the volume and incidence of major spills in Washington State may be declining more abruptly than that indicated by national and international trends.

The year Washington passed its major oil legislation (1991), we experienced 3 major spills over 10,000 gallons. During this apparently anomalous year, incidents resulted in the loss of 100,000 gallons from the Tenyo Maru; 600,000 gallons from US Oil and Refining; and 210,000 gallons from Texaco refining.

The annual average volume of oil spilled in Washington State from petroleum oil spills greater than 10,000 gallons during 1987-91 was 327,000 gallons. The volume of oil spilled during the five-year period from January 1992 through June 1996 was 72,000 gallons — a 78 percent reduction. Both Ecology and the state Office of Marine Safety's spill prevention and response efforts were fully funded and staffed by June 1992. However, one should be cautious when interpreting the significance of these trends in relation to the effectiveness of the state's program given:

- The highly variable nature of the data (especially spills during 1991);
- The fact that spill incidents have a higher probability of being reported in more recent years;
- The fact that spill volumes are more accurately reported now; and
- The regulatory programs of the Coast Guard and EPA under the federal Oil Pollution Act of 1990, while not visibly affecting national trends may have had a regional effect.

Figure 2 — Major Oil Spills in Washington State Over 10,000 Gallons: Volume of Spills Per Year in Gallons



The cause and effect of such broad trends cannot easily be determined in a complex milieu such as spill prevention. Factors which weigh heavily in determining outcomes include human considerations such as legal liability, criminal liability and corporate philosophy. Non-human considerations include weather patterns, environment and sea conditions. Furthermore, a single catastrophic spill such as the *Exxon Valdez* can significantly skew the data.

However, with these limitations in mind, Ecology attributes this apparent decline in the volume of oil spilled in Washington from major incidents to a broad effort by industry, the public sector and public interest groups to prevent these incidents. In addition to the efforts by state agencies:

- The major oil refineries and marine terminals have enhanced corporate policies, developed more effective spill prevention and response plans, improved personnel training and dedicated more resources to equipment maintenance among other initiatives;
- Oil tanker and regional tank barge operators have invested heavily in clean-up equipment and personnel improvements — including procedures, training, crew rotation and spill response equipment;
- The domestic cargo vessel industry has placed a much higher priority on spill prevention than in the past;
- The Coast Guard has enhanced the vessel traffic system;
- In the Northwest, the Coast Guard and EPA have been very active in implementing the federal Oil Pollution Act of 1990; and
- The efforts by local government, tribes and environmental groups have been particularly important in keeping private and public sector stakeholders focused on effective prevention measures.

While this data relates to volume, it does appear to be consistent with trends identified in national spill statistics by American Petroleum Institute (API). API concluded that during the decade ending in 1994, the *frequency* of large spills declined by 57 percent.

Source of Major Spills

Figures 3 and **4** display the number of vessel, facility and transmission pipeline spills in the database. As previously mentioned, data on spills from surface transportation modes, such as rail and truck, has not been consistently collected and therefore was not included in the statistics.

Figure 3 — Major Oil Spills Over 10,000 Gallons: Number of Spills by Source

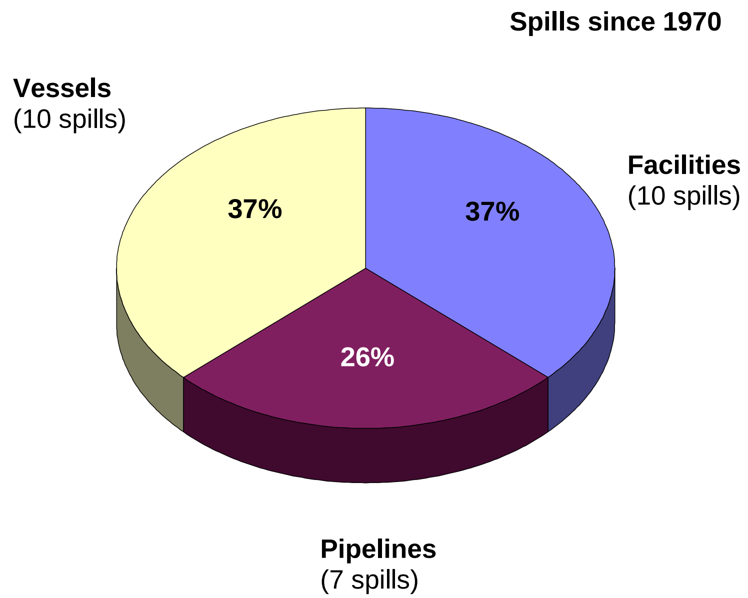
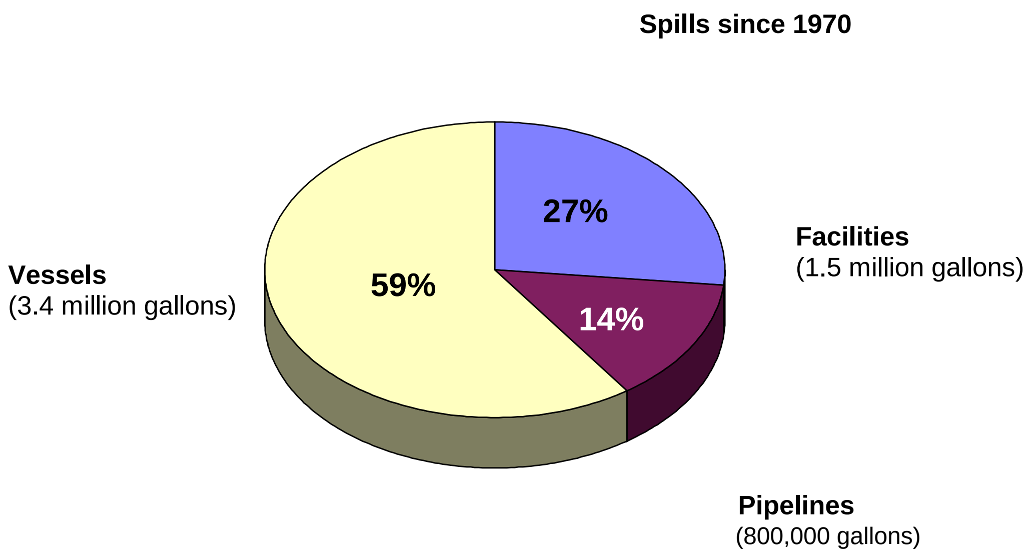


Figure 4 shows the volume of oil spilled from the marine industry (3.4 million gallons) is larger than that spilled by facilities and pipelines (2.3 million gallons). The two figures combined indicate that the size of major vessel spills exceeds that of facility and pipelines. This data is heavily influenced by several large volume marine accidents which have occurred on the coast and in the Strait of Juan de Fuca.

The data indicates that major pipeline spills are generally smaller than major vessel or major facility spills. However, as discussed later in this report, there has been a recent series of major pipeline spills.

The American Petroleum Institute has concluded that “large spills of 10,000 gallons or more accounted for nearly 90 percent of the total oil spilled during the last decade.” State data appears to support this conclusion.

Figure 4 — Major Oil Spills Over 10,000 Gallons: Total Volume of Oil Spilled by Source



Types of Oil Spilled

Figures 5 and **6** display information on the number and volume of oil spilled by product type. The figures show that heavy fuel and crude oils, which are the most environmentally damaging types, are the largest amount of oil spilled in the state. These viscous “black” oils have a tendency to smother animals such as birds and mammals, often killing them. These oils are also highly persistent and create residues which are resistant to natural physical and biological degradation processes.

Figure 5 — Major Oil Spills Over 10,000 Gallons: Number of Spills by Type

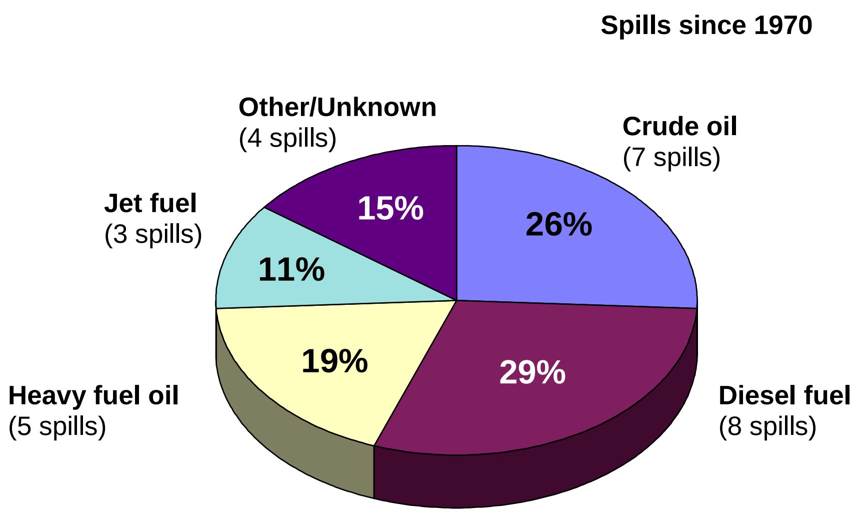
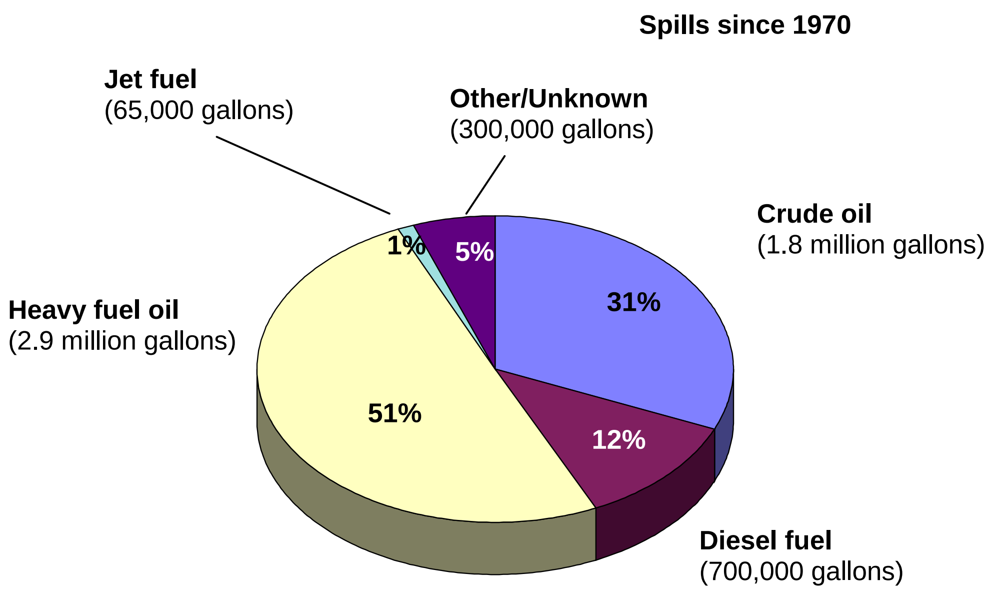


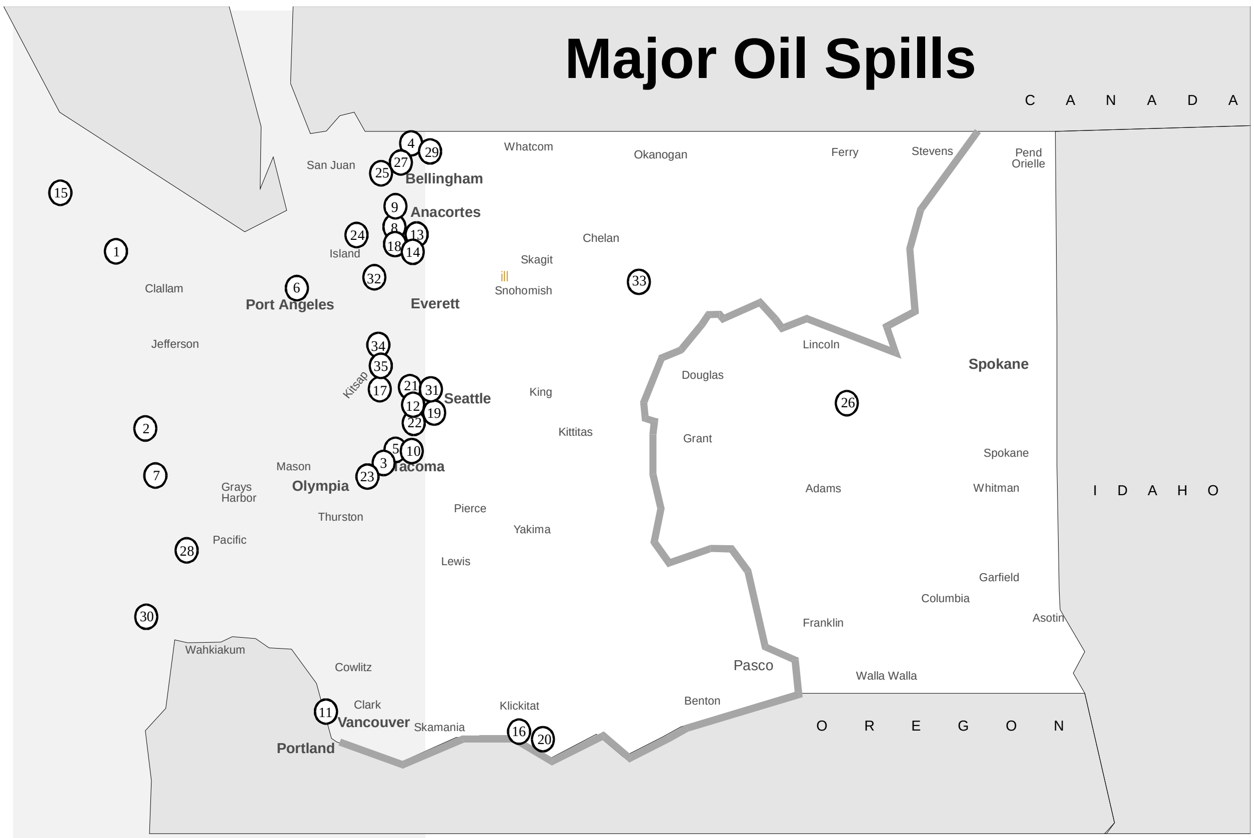
Figure 6 — Major Oil Spills Over 10,000 Gallons: Volume of Oil Spilled by Type



Geographical Distribution

Figure 7 is a map of the state showing the locations of the major spills, and includes additional spills not analyzed in **Figures 2-10**. The additional spills are noted in **Appendix 4**. The map shows a clustering of large spills in Puget Sound and dispersed along the coast and Strait. **Appendix 4** provides a detailed list of these spills.

Figure 7: Location of Major Oil Spills Over 10,000 gallons



Figures 8 and **9** show the distribution of the number and volume of major oil spills in Ecology's four regional offices. A map depicting the jurisdictional boundaries of each regional office is found in **Appendix 5**. More oil was lost from major spills in the agency's southwest regional office than the three other regions combined. This is likely due to this region's long marine shoreline which encompasses all of the state's Pacific coast line, the Strait of Juan de Fuca and much of Puget Sound.

Figure 8 — Major Oil Spills Over 10,000 Gallons: Number of Spills by Regional Office

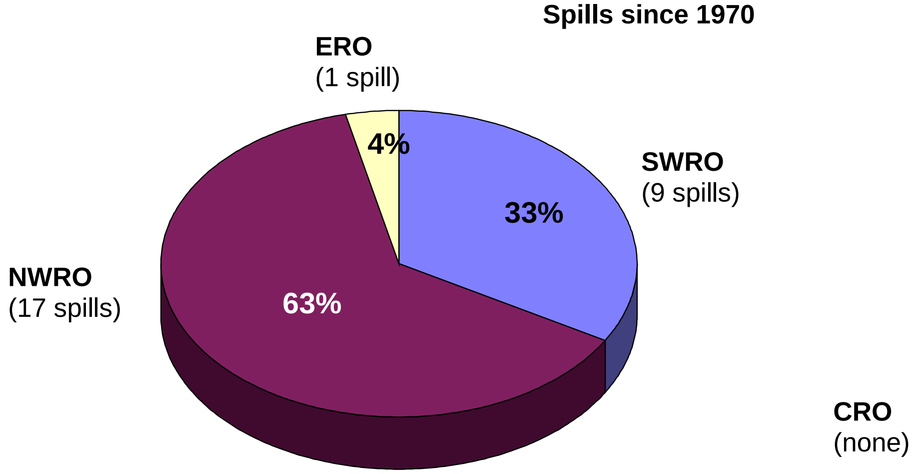
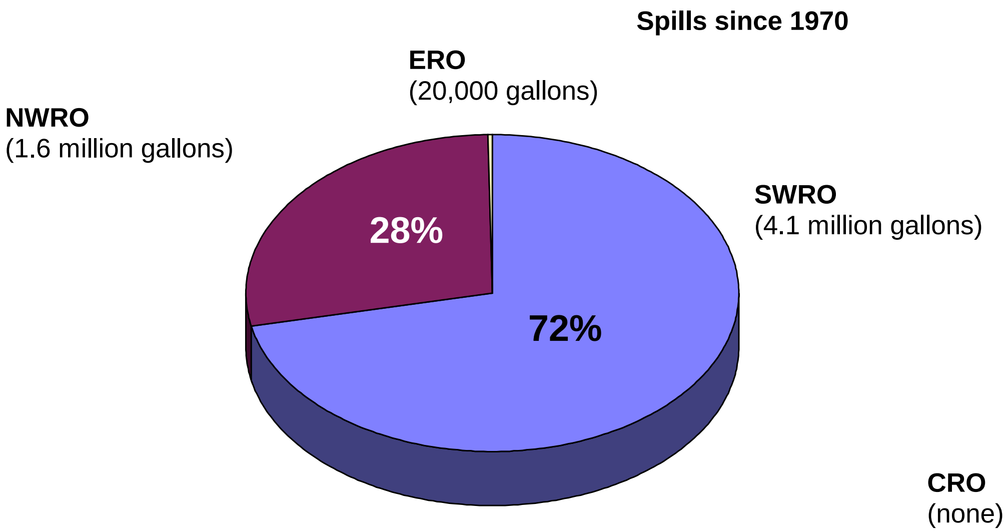


Figure 9 — Major Oil Spills Over 10,000 Gallons: Volume of Spills by Regional Office

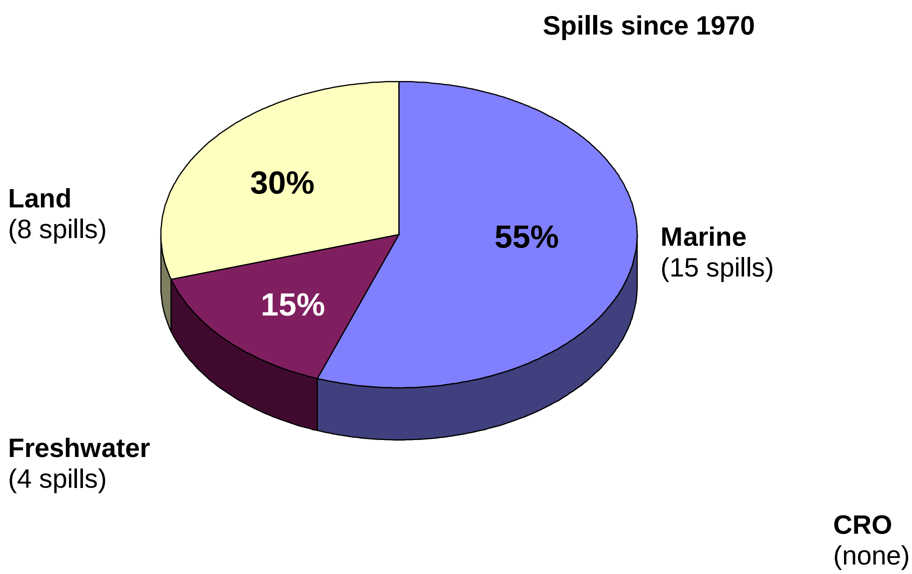


While the largest spills occurred in the SWRO, the northwest regional office (NWRO) actually received more spills greater than 10,000 gallons. This is due to the large population and activity levels centered in Seattle, Bremerton and, to a lesser extent, the northern refineries.

The data probably under represents the volume and number of spills in the Central (CRO) and Eastern (ERO) regions because surface transportation incidents were not included in the analysis. CRO has reported the greatest number of multi-thousand gallon petroleum product spills from tanker truck rollovers. Winter mountain pass conditions undoubtedly contribute to the number of truck accidents.

Figure 10 shows the distribution of spills by receiving environment. Slightly over half of the spills effected the marine environment. In 45 percent of the major spills, impacts were primarily limited to freshwater habits and the land. While land spills often have a lower degree of impact on the environment they can have serious consequences upon public health if they affect drinking water wells, and to public safety if gasoline fills buildings with explosive and/or toxic vapors.

Figure 10 — Major Oil Spills Over 10,000 Gallons: Number of Spills by Impacted Medium



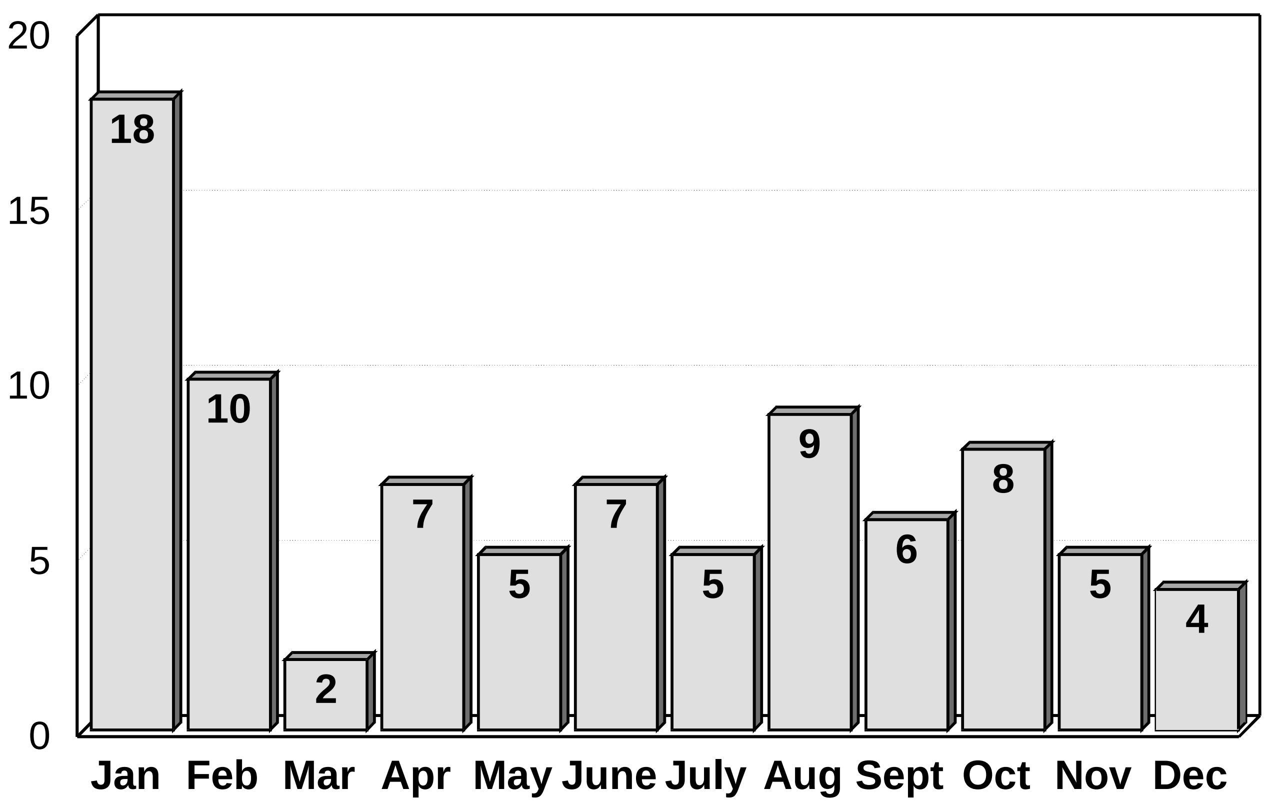
Chapter 4: Recent Trends in Oil Spills

This section evaluates information on spills between 25 and 10,000 gallons which have occurred between June 30, 1992, and July 1, 1996. The spills included in this data set include 86 vessel and facility spills and six pipeline spills where at least 25 gallons of oil reached water or at least 250 gallons was spilled on land. Truck and train transportation incidents are not included in this data.

Distribution of Recent Spills

Figure 11 compresses the most recent four years of facility and vessel spill data into a single 12 month bar chart. While we must be careful in not over interpreting the graph given the relatively few data points in each month, it does appear that spill frequency peaks during January. This phenomena has been observed by others and may be explained by probability of human error increasing during cold, dark climatic conditions and the holiday season.

Figure 11 — Distribution of Oil Spills Over Time: Number of Vessel and Facility Spills by Month
(pipelines not included)



Source of Recent Spills

As shown in **Figures 12** and **13**, our information indicates that for these medium sized spills, the number of vessel incidents is significantly larger than the number of facility and pipeline incidents combined. The volume of oil spilled from the marine industry is also large compared with facilities and pipelines.

Figure 12 — Recent Spills 25 to 10,000 Gallons: Number of Oil Spills by Source

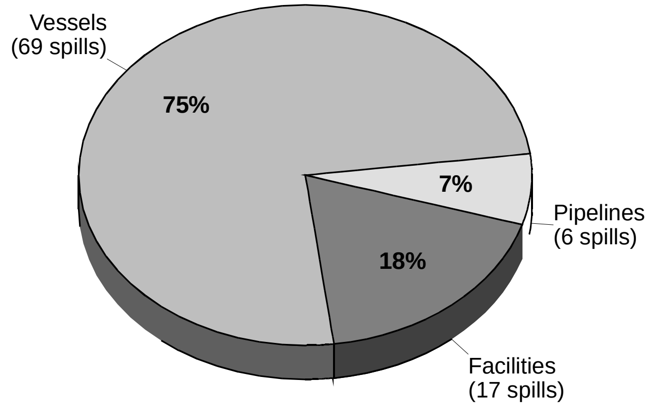
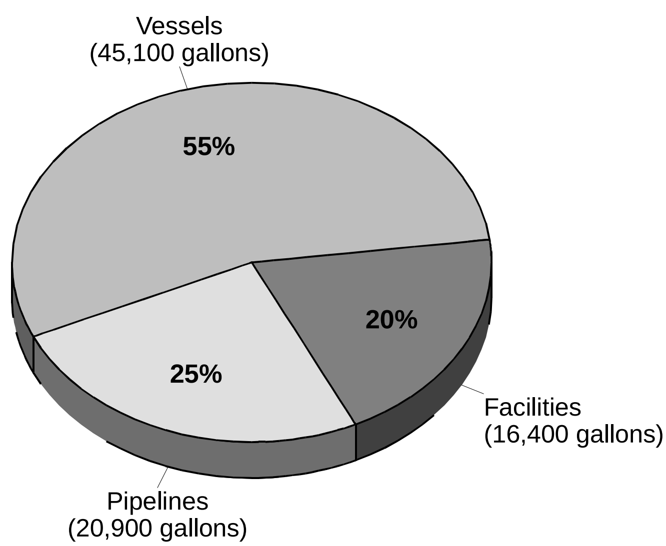


Figure 13 — Recent Spills 25 to 10,000 Gallons: Volume of Oil Spilled by Source



Overall, there are a relatively large number of medium sized vessel diesel fuel spills. However, another observation is that pipeline spills tend to be larger than vessel or facility spills (see **Figure 13**) for this data set. While pipelines account for only seven percent of the spill incidents, they resulted in 25 percent of the volume of spilled oil.

Types of Oil Spilled

Figures 14 and **15** describe the number and volume of oil spills by product type. In contrast to the major spills which were dominated by heavy fuels and crude oil, diesel spills dominate the number and volume of recent medium-sized spills. In this data set, crude oil spills are relatively infrequent while heavy fuel oil spills contributed to the total volume of spilled oil. In general the heavy fuel oil spills were larger than other incidents. This is due to the occurrence of relatively large vessel bunkering spills. Had rail and truck incidents also been included, they would have further increased the number and volume of diesel and gasoline spills.

Figure 14 — Recent Spills 25 to 10,000 Gallons: Number of Spills by Oil Type

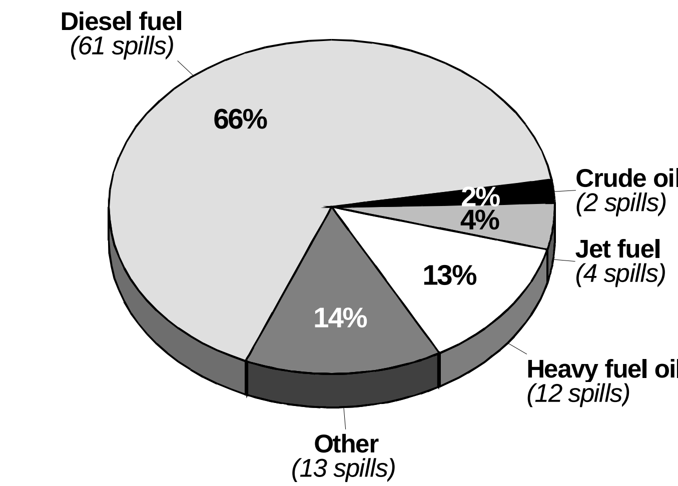
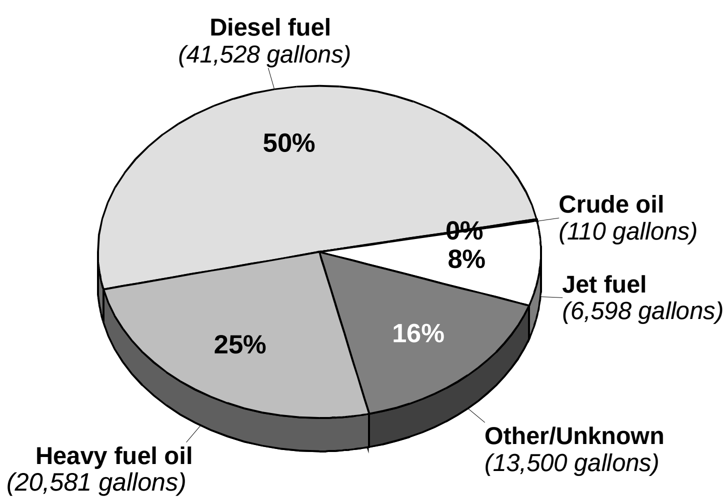


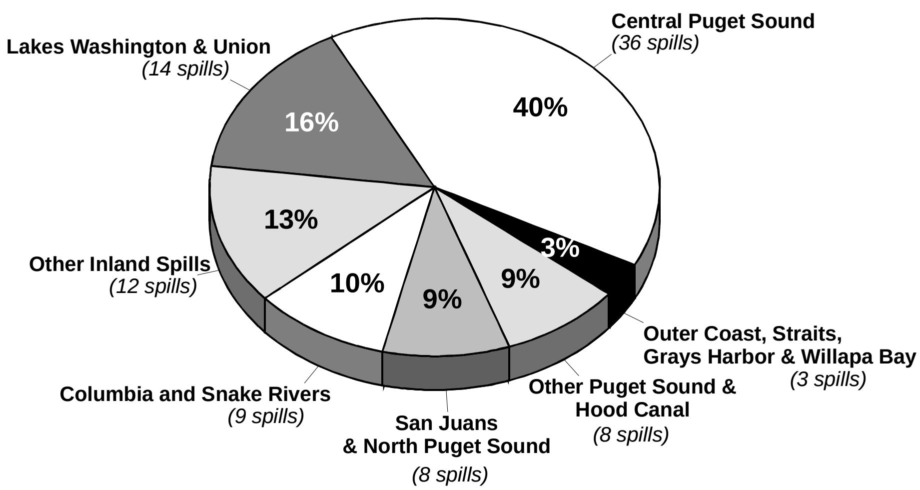
Figure 15 — Recent Spills 25 to 10,000 Gallons: Volume of Spills by Oil Type



Geographical Distribution

Figure 16 shows the distribution of spills among the Northwest Area Committee's Geographic Response Plans (GRP). More than half of the spills (50) occurred in the Central Puget Sound GRP and in Lakes Washington and Union. This area includes the state's largest population center, the Seattle/Tacoma metropolitan area. Other areas experiencing large numbers of spills included the San Juan Island/North Puget Sound area and the Columbia River.

Figure 16— Recent Spills 25 to 10,000 Gallons: Spill Distribution by GRP



Figures 17 and **18** show the distribution of spills among Ecology's regional offices. The northwest regional office (NWRO) experienced more spills than any other region. However, the amount of oil spilled in the southwest region (SWRO) was approximately equal to that of the more populated northerly region. Interestingly, over both spill size distributions discussed in this report (spills greater than 10,000 gallons discussed in **Chapter 3** and the data in this chapter), spills in SWRO were larger than NWRO. This data again probably under represents the volume and number of spills in the central and eastern regions because surface transportation incidents (rail and truck) were not included in the analysis.

Figure 17 — Recent Spills 25 to 10,000 Gallons: Number of Spills by Ecology Region

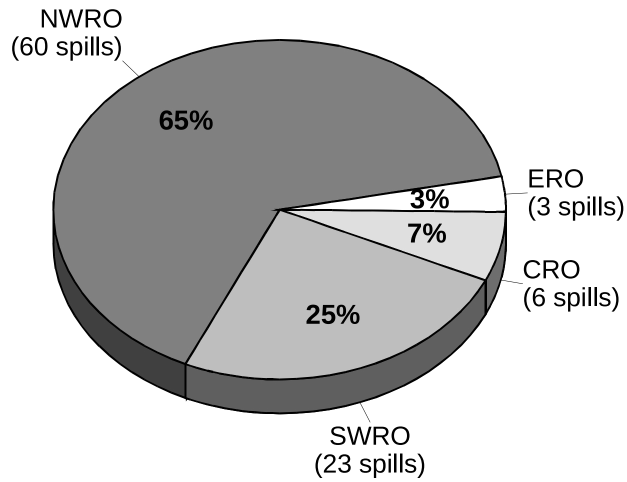
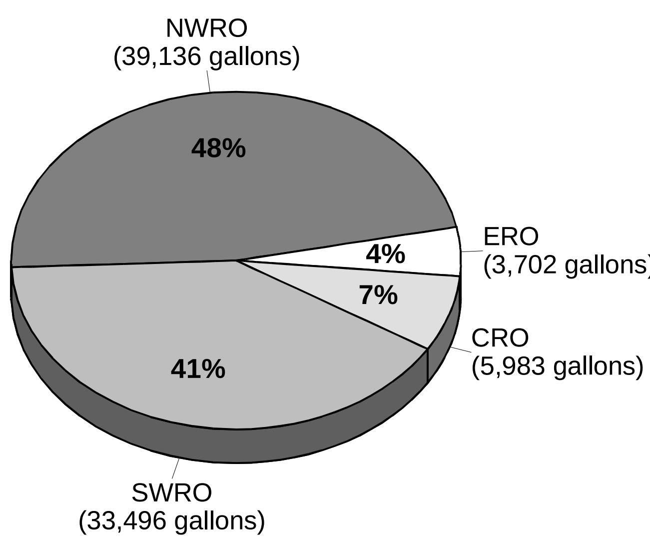


Figure 18 — Recent Spills 25 to 10,000 Gallons: Volume of Oil Spilled by Ecology Region



Figures 19 and **20** show that similar to the major spills discussed earlier in the report, recent medium-sized oil spills have had a significant impact on the marine waters compared with freshwater and land environments. However, primarily as a result of pipeline spills, land spills which represent only nine percent of the spills by number resulted in 29 percent of spills by volume.

Figure 19 — Recent Spills 25 to 10,000 Gallons: Number of Spills by Impacted Medium

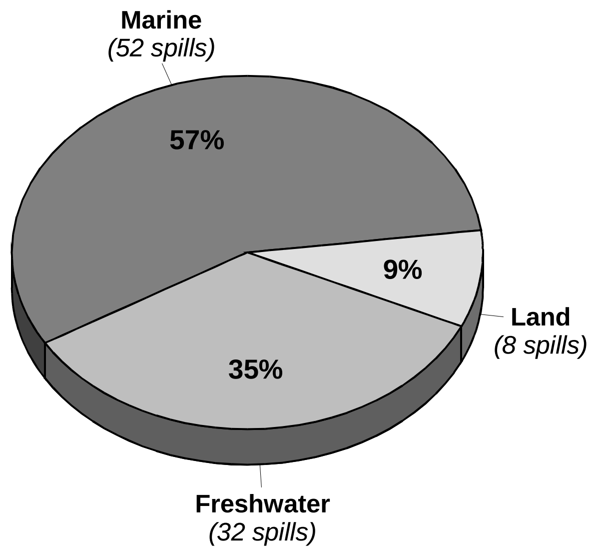
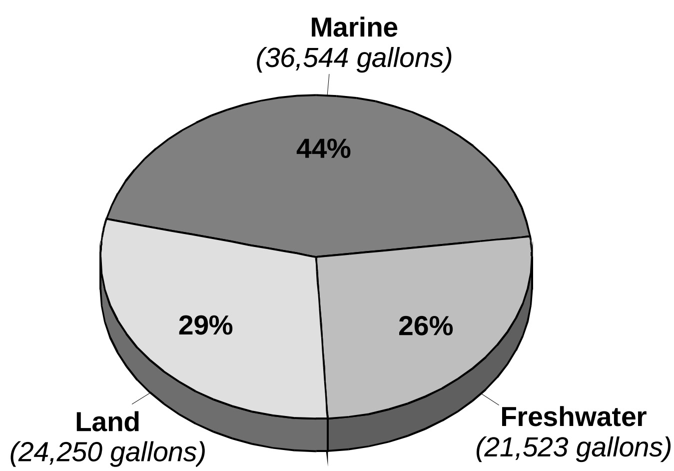


Figure 20 — Recent Spills 25 to 10,000 Gallons: Volume of Spills by Impacted Medium



Comparison with Coast Guard Data

The U.S. Coast Guard maintains a national data base which can be used to evaluate both national and regional trends in oil spills. Spill data from 1991-1995 currently under review by the Coast Guard's District XIII staff in Seattle, seems to confirm the general trends shown in **Figure 13.** This data for the Puget Sound Marine Safety office indicates that 62 percent of the volume of oil spilled came from vessels, 34 percent came from facilities and four percent from another source.

National trends identified by the Coast Guard's "Marine Environmental Protection Performance Indicators" indicates that major and medium sized oil spills may be trending downward. This potential trend appears to be consistent with **Figure 2** of this report. Ecology will continue to work closely with our federal partners to track and report on trends as they emerge.

Cause of Recent Spills

The analysis and understanding of the causes of major spills is not as simple. There are a myriad of reasons for this, including:

- **Most major spills are difficult to analyze** given that they are often the result of a series of complex factors and conditions coming together at a particular moment in time. The factors may include both failures which are preventable, and conditions which are not within human control. Often a major incident would not have occurred if any one of the factors or conditions had been absent. Therefore, it is often difficult to boil an incident down to a single primary/root cause with identified contributing factors.

- **There is a lack of a consistent framework** for systematically analyzing and categorizing incidents. This is a problem both nationally and in Washington State.

- **There is lack of consistently collected reliable information** on spill causes. This is partially due to the scarcity of highly trained staff resources in the investigating agencies, the reluctance of industry to fully disclose information for liability reasons and the lack of agency funding to hire independent experts to conduct professional investigations.

- **There is also a reluctance on the part of many investigators** to directly place blame because of liability concerns, sympathy for an individual or organization who has already been affected by an incident, and concern that an employee who may have contributed to an incident may lose their livelihood. The result is that some investigations identify the cause of an incident as equipment failure or a natural event, even when an easily preventable human error (individual or organizational) occurred.

However, there is a consensus that most major spills are caused by some form of human error and are therefore preventable. In order to provide additional insight into the types of human error, this report further distinguishes between individual human factors and management/organizational factors. The terms used in this report are defined as follows:

- **Management/Organization —** The failure of an organization to provide the necessary policies, procedures, equipment, personnel, supervision, training or time to safely design and operate a system which could potentially cause a spill. In order to prevent spills, an organization may be expected to go beyond currently accepted industry practices.

- **Human Factor —** The diminished ability (over which the organization has relatively little control) of an individual to safely complete a task. Examples include poor communication, drugs/alcohol, improper equipment use, inaccurate computation, inattention, procedural error, complacency, not following training procedures, fatigue, illness or sabotage/intentional.

- **Equipment —** A mechanical, structural or electrical failure not attributable to a human error-related design, material specification, manufacture/construction, installation, operation or maintenance deficiency. An example which would not qualify for this category as an "equipment failure" would be a failure from normal wear and tear as a result of lack of maintenance. This would be either a management/organization or human factor caused spill.

- **External —** Natural phenomenon such as earthquakes, floods, storms, tsunami, fog, ice, lightning, tidal conditions, sea state and landslides which occur with a magnitude outside of reasonably anticipated design or operating limits. An example of an external cause could be any act caused by Mother Nature.

For the reasons stated earlier, Ecology's data on spill cause is somewhat limited. Ecology is working to improve the systems for collecting, analyzing and maintaining spill cause data. Current initiatives include the development of an investigator training curriculum, hiring independent experts on major spills and the States/BC Oil Spill Task Force's project to provide a consistent methodology for collecting and sharing spill data on the entire West Coast.

Figures 21 and **22** show the distribution of spill causes for 41 recent spills in Washington (Note: incident cause was not identified in 51 of the other spills analyzed in this section). Based on the limited information available to Ecology, it appears that "human error" at the levels of the organization and individual predominate. Of the four cause definitions, organizational failure is the primary cause of recent spills in terms of both number of incidents and total volume of oil spilled. Human factors are the second most predominant cause of these spills.

The conclusion that human error is the primary cause of most spills is supported by findings by the Washington State Office of Marine Safety, the California Lands Commission, the U.S. Coast Guard, the Alaska Department of Environmental Conservation and most industry analysts. The definitions used in this report are identical with those being developed by the States/British Columbia Task Force for the purpose of consistently collecting cause data in the future on the West Coast.

Figure 21 — Recent Spills 25 to 10,000 Gallons: Number of Spills by Cause

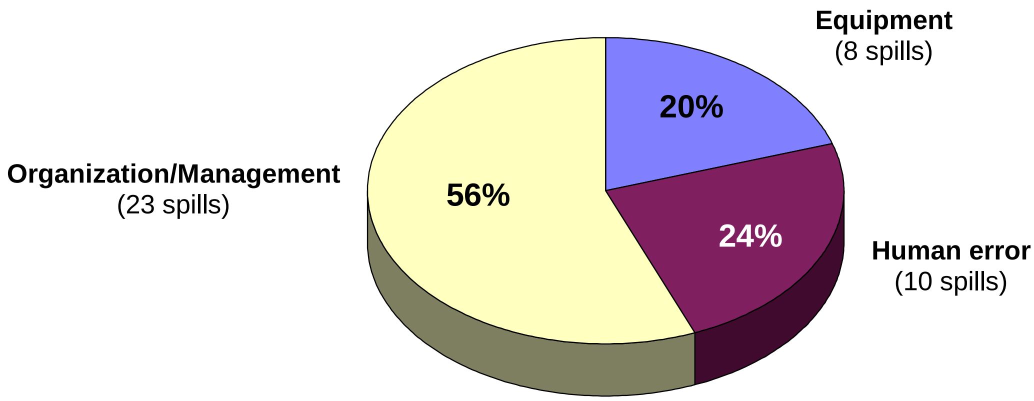
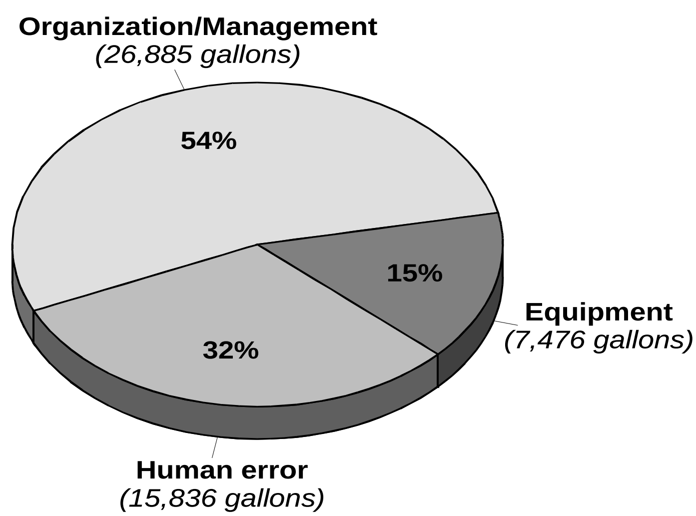


Figure 22 — Recent Spills 25 to 10,000 Gallons: Volume of Oil Spilled by Cause



Chapter 5: Near Miss Incidents

This report's **Appendix 1: Significant Vessel Casualties and Near Miss Incidents** is a list of important vessel-related incidents where there was either a major system failure or actual external damage to a vessel that occurred between 1984-96. Those incidents which did not result in the release of oil are considered to be close calls. When they are properly investigated, as much can be learned about spill prevention from these incidents as from actual spills. The state Office of Marine Safety (OMS) is currently working with other stakeholders to put a system in place which would collect information on more of these vessel incidents.

If these collisions, groundings, allisions (collision with a fixed object) and losses of power were plotted on the map outlining Washington's major oil spills **(Figure 7)**, they would largely parallel the locations where major spills have actually occurred.

Given the difficulty in agreeing on what constitutes a "near miss," the lack of incentives for reporting these incidents and the liability concerns of facility owners, it would be difficult to establish a reporting system for major non-spill incidents at marine facilities and transmission pipelines. However, Ecology will continue to follow progress by OMS and the marine industry to determine if similar discussions should be initiated with the industry segments which Ecology regulates.

Chapter 6: Lessons Learned From Recent Pipeline Spills

Over the last few years pipeline spills have occurred nationally with a frequency and environmental consequence that have raised significant concerns from the National Transportation Safety Board and others. The potential for similar major oil spills exists in Washington State. For example, two past pipeline spills involved the release of 460,000 and 168,000 gallons. These incidents show how much oil can be spilled by pipelines before the leak is detected, the system is shut down and residual drain out is controlled.

In Washington State, the major oil transportation pipelines spill only a very small portion of the products they transport. However, because of the large amount of oil which can be spilled before a spill incident is identified and controlled, they have the potential to cause serious environmental damage. Spill events during 1996 have demonstrated the need for Ecology to review current spill prevention measures for the state's major oil transportation pipelines. During 1996, the following incidents occurred:

- **On March 23, 1996, an estimated 1,560 gallons of diesel fuel** spilled from the Olympic Pipe Line into a tributary to Spencer Creek in Cowlitz County. The spill was caused by damage to the pipeline as a result of ground slumping in unstable soil in the area surrounding the pipeline.

- **On June 16, 1996, at least 1,000 gallons of gasoline and diesel fuel spilled** from a small crack in the Olympic Pipe Line into an unnamed slough near Everett. The cause of the spill may have been due to construction damage during original installation in 1972.

- **On Dec. 6, 1996, approximately 49,000 gallons of unleaded gasoline spilled** at the GATX oil storage facility on Harbor Island in Seattle. The spill resulted from a pipeline coupling failure at the plant during a product transfer from the Olympic Pipe Line. The specific cause of the spill is still under investigation and has not been determined.

It is often difficult to determine the quantity of oil lost during pipeline spills. For instance, the two Olympic Pipe Line spills went undetected for a significant period of time while oil entered soils and state waters. Ecology will continue to review the cause of these and other similar events with industry to gain a better understanding of how these spills can be prevented. This review is particularly important at this time, given the proposal for a major cross-Cascades petroleum pipeline. The state has a responsibility to assure that any new or repaired pipeline sections are constructed and operated in an optimal manner to minimize the opportunity for spills.

As a result of recent pipeline spills, Ecology is evaluating the need for industry to put in place additional protection measures. However, at this time Ecology does not have resources to institute a transmission pipeline spill prevention effort.

Conclusions

We have reached a number of conclusions after reviewing the information presented in this report. These conclusions were not based on a statistical analysis but were developed by inference after evaluating the data. The conclusions presented below are arranged by category, not priority.

Data Collection and Analysis

- **Resources needed for data collection:** Readily accessible historical data on major spills prior to the mid-1980s is incomplete. Ecology will continue to improve the collection of this information in order to better analyze the cause of significant oil spills and help the agency target its prevention efforts. This needed improvement will require Ecology to continue current efforts to improve investigator training and commit additional resources to information management. There is also a need to improve truck and rail data in particular, given the gap in this report.

Important Trends in Spills

- **Human error causes most spills:** Ecology's spill cause data indicates that most recent spills (about 80 percent) were the result of some type of human factor and were, therefore, preventable. It also appears that organization/management is responsible for significantly more incidents than the failure of an individual. These conclusions are consistent with the findings of other researchers at the national level and have important implications for spill prevention.

- **Spills occur most frequently in January:** During the last four years, the annual incidence of significant oil spills was highest during January. While we need to better understand the reasons for this seasonal influx, one factor suggests the importance of addressing the human factors component in oil spills.

- **Spills over 10,000 gallons are source of most oil:** The overall quantity of oil spilled is dominated over time by large spills greater than 10,000 gallons. The state should continue to target prevention activities for potential major spill sources. However, this report did not evaluate non-point source oil inputs to the environment, which are seldom reported to environmental agencies and can add up to large volumes. Non-point sources include leaking motor vehicle crank cases, parking lot run-off, improper disposal of used motor oil and other similar sources.

- **"Black" oil is a serious threat:** Crude and heavy fuel oils have constituted about 82 percent of the total oil released from spills over 10,000 gallons. These forms of "black" oil are among the most persistent and environmentally damaging types of oil and are very difficult to clean up. Future spill prevention efforts should continue to address vessel spills which were responsible for about 59 percent of the total volume of oil lost from major spills and many of the incidents involving black oil.

- **Biggest risk is associated with marine transportation corridors:** The outer coast, the Strait of Juan de Fuca and the vicinity surrounding the state's major refineries are the areas at greatest risk of major spills.

- **Transmission pipelines present significant risk:** During the last four years, the volume of oil released per spill from pipeline incidents was relatively large compared with routine vessel and facility spills. With the continued occurrence of these spills, industry and Ecology should place additional emphasis on prevention of spills from major transmission pipelines.

Effectiveness of Existing Spill Prevention Measures

- **Big spill incidents may be dropping:** While it is difficult to clearly attribute the long-term trend in spills over 10,000 gallons to any specific measure, it does appear that since 1983 the number and volume of major spills in Washington has gone down (see **Figure 2**). Furthermore, this apparent decline may be occurring more rapidly than national rates. If this is true, it has good implications for the effectiveness of the state/federal and industry spill prevention partnerships which have been developed in Washington since the passage of the state's spill prevention legislation in 1991. However, the state must guard against complacency and losing focus on spill prevention.

- **Land-based spills continue to pose risk:** Washington has information on 15 petroleum oil spills of over 100,000 gallons since 1964. These major spills have included tanker and barge accidents, refinery accidents and major transmission pipeline releases. While vessel spills may present the greatest risk for catastrophic spills, refinery and transmission pipeline operations have resulted in four of the last five spills over 10,000 gallons. These facilities should continue to be the primary focus of Ecology's spill prevention efforts.

State Spill Policy

- **Effect of spills on state legislation:** As indicated in **Appendix 2**, there is a strong connection between the incidence of oil spills and subsequent legislative expansion of state responsibilities for spill prevention and response. We can expect that the future occurrence of major spills will trigger additional public expectations for improved spill prevention measures.

- **Washington has a unique energy policy setting:** Washington State has not depended solely on federal rules for the protection of its natural resources, but has established its own stringent oil spill prevention and response program. The primary factors which have influenced state policy in this area (other than actual spill events) include: the high sensitivity and value of Washington's aquatic resources; the large volume of Pacific rim trade; and the state's reliance on external crude oil resources.

- **Petroleum products exported from Washington are subject to a tax credit:** Washington State refines large volumes of petroleum products. A significant portion of the refined products are exported to Oregon and California. While our state is exposed to the spill risks associated with the importation, processing, storage and export of those products, Washington's spill prevention and response programs do not receive tax revenue from petroleum which is exported.

Appendices

Appendix 1 — Significant Vessel Casualties and Near Misses

- **August 12, 1996, Grounding —** A loaded grain ship, the *Ossolineum* grounded along the banks of the Columbia river. The vessel, which was outbound, was carrying 350,000 gallons of fuel in its tanks when it ran aground upstream from three wildlife refuges and estuaries. Luckily no oil was spilled.

- **July 11, 1996, Loss of Power —** The oil tanker *Kenai* lost power off Port Angeles. The tanker was headed toward Valdez when it stopped at Port Angeles to have its radar fixed and to refuel for the voyage. Fortunately, an escort tug was near by when the vessel lost power and was able to bring the vessel back to Port Angeles without incident.

- **July 6 1996, Shipboard Fire —** The cruise ship *Golden Princess* was headed to Vancouver, British Columbia, when a fire in the engine room caused the engines to shut down. The vessel also lost electrical power. A tug boat arrived on scene in three hours to tow the vessel to Vancouver for repairs. The vessel was carrying over 600,000 gallons of fuel when it lost power.

- **October 1994, Grounding —** The empty tanker *Keystone Canyon* broke all of her mooring lines in high winds while moored in Astoria, Oregon. The ship drifted across the Columbia River and struck the Astoria-Megler Highway Bridge. Fortunately, damage to the ship and the bridge was minimal. No oil was spilled although an empty tank was breached. A combination of weather conditions and lack of procedures lead to the grounding.

- **July 1994, Loss of power —** The 32,671 bulk carrier *Verbier* was outbound from Vancouver, British Columbia, when it lost power 2.5 miles from shore in the Strait of Juan de Fuca. After an unsuccessful attempt to be towed to port by a small tug, a second larger tug was dispatched. After several hours of towing, the tow line parted. The tug made-up again, and successfully towed the vessel to Port Angeles with the final assistance of tow other tugs. Lack of proper owner and operator oversight and support contributed to the accident.

- **July 1994, Collision —** The Chinese bulk freighter *Tian Tan Hai* collided with the fully laden tank barge *Cascades* approximately 30 miles west of the Columbia River entrance. The *Cascades* was being towed by the tug *Fairwind* and was carrying 2.4 million gallons of oil. Fortunately no oil was spilled because the collision did not rupture any cargo tanks on the barge or fuel tanks on the freighter. The barge was double-hulled. Lack of communication and adherence to regulations and policy contributed to this collision.

- **November 1993, Explosion —** The tanker *Sea River Philadelphia* suffered an explosion in her Inert Gas compartment while moored in Anacortes. Fortunately no one was injured and no oil was spilled. Inadequate maintenance procedures and possible inadequate design contributed to the explosion.

- **July 1993, Poor Vessel Condition —** The tanker *Altair* was boarded and briefly detained in Victoria, British Columbia, by the Canadian Coast Guard. The ship was in poor condition. Two months later, the *Altair* blew up and sank in the South China Sea.

- **June 1991, Grounding —** The laden tanker *ARCO Texas* ran aground at Ediz Hook in Port Angeles, Washington. No release of oil occurred.

- **September 1989, Loss of power —** The tanker *Exxon San Francisco* lost power while outbound in the Strait of Juan de Fuca. The vessel returned to Port Angeles without further problems.

- **April 1989, Loss of power —** The tanker *Exxon Philadelphia* lost power and was adrift off the mouth of the Strait of Juan de Fuca with a load of 23 million gallons of Alaska crude oil. Approximately five hours later, a tug reached the tanker and towed the ship to Port Angeles.

- **April 1988, Grounding —** The tanker Matsukaze grounded at Crescent Bay west of Port Angeles causing extensive damage to the vessel but no loss of product.

Appendix 2 — Major Oil Spills and Related Legislative Action

1964
- United Transportation Barge, Grays Harbor Co. (3/64) — 1,200,000 gallons diesel fuel

1969
- Extensive oil spill legislation was passed in 1969-1972

1971
- United Transportation Barge, Skagit Co. (4/71) — 230,000 gallons of diesel/gasoline

1972
- *General M.C. Meiggs* (U.S. Navy), Clallam Co. (1/72) — 2,300,000 gallons of fuel oil

1973
- Trans Mountain Pipeline, Whatcom Co. (1/73) — 460,000 gallons of crude oil

1983
- Olympic Pipe Line Co., Allen Pump Station (9/83) — 168,000 gallons of diesel fuel

1984
- *Tanker SS Mobil Oil*, Columbia River (3/84) — 200,000 gallons of fuel oil

1985
- Olympic Pipe Line, King Co. (11/85) — 34,000 gallons of jet fuel
- *ARCO Anchorage*, Port Angeles (12/85) — 239,000 gallons of crude oil

1986
- Concurrent Legislative Resolution 19 established an oil spill advisory committee
- Olympic Pipe Line, King Co. (5/86) — 70,000 gallons of oil

1988
- *Barge MCN#5* (Olympic Tug & Barge), Skagit Co. (1/88) — 70,000 gallons of heavy oil.
- *Nestucca Barge* (Sause Towing), Grays Harbor Co. (12/88) — 231,000 gallons of fuel oil.

1989
- HB 2242 — Established financial responsibility requirements for vessels.
- SB 6701 — Washington State Maritime Commission (WSMC) established.
- HB 1853 & 1854 — Natural Resource Damage Assessment methodology.
- *Exxon Valdez* grounding, AK (3/89) — 11,000,000 gallons of crude oil. This spill resulted in significant legislative changes in Washington, as well as other U.S. states and Canada.

1990

- HB 2494 — Broad spill preparedness & contingency planning legislation
- HB 6528 — Pilotage legislation
- OPA 90 — Passage of the Federal Oil Pollution Control Act of 1990
- Navy Supply Depot, Kitsap Co. (2/90) — 70,000 gallons of diesel fuel
- Texaco, Skagit Co. (3/90) — 130,000 gallons of diesel fuel
- Chevron Richmond Beach, King Co. (8/90) — 176,000 gallons of asphalt
- PNW Terminals, Pierce Co. (11/90) — 200,000 gallons of tallow

1991

- HB 1027 — Broad legislation with a spill prevention focus
- US Oil Tacoma, Tacoma (1/91) — 600,000 gallons of crude oil
- Texaco Refinery, Anacortes (2/91) — 210,000 gallons of crude oil
- *Tenyo Maru* (COSCO Shipping), Canadian waters at entrance to Strait of Juan de Fuca (7/91) — 100,000 gallons of diesel & heavy oil

1992

- HB 2389 — Amendments to 1991 legislation
- Chevron Pipeline, Lincoln Co. (11/92) — 20,000 gallons of jet fuel

1993

- HB 1144 — Established OMS vessel inspection program
- US Oil Refinery, Tacoma (10/93) — 264,000 gallons of crude oil
- *M/V Nosac Forest* (Barber International), Tacoma (4/93) — 6,260 gallons of fuel oil
- *M/V Central* (Azuero Shipping), Columbia River (6/93) — 3,000 gallons of fuel oil

1994

- ESHB 1107 — Marine Oversight Board Abolished
- HB 1407 — Washington State Maritime Commission privatized
- Crowley Barge 101, Rosario Strait (12/94) - 26,900 gallons diesel of fuel
- An Ping (Shanghi Hai Xing Shipping), Columbia River (1/94) - 2,771 gallons of fuel oil

1995

- ESHB 2080 — Merged OMS with Ecology, legislation was struck down by superior court action

1996

- Initiative 188 fails — Bans off-shore drilling; eliminates OMS merger; adjusts spill funding
- GATX, Harbor Island Seattle (12/96) — 49,000 gallons of unleaded gasoline

Appendix 3 — Selected Spills in Washington State

(Arranged by date)

Incident Date	Incident Name	Total Quantity Spilled (Gallons)	Product Type
03/10/1964	V-UNITED TRANSPORTATION BARGE	1,200,000	DIESEL FUEL
04/26/1971	V-UNITED TRANSPORTATION BARGE # U	230,000	DIESEL FUEL
01/01/1972	V-GENERAL M.C. MEIGGS	2,300,000	HEAVY FUEL OIL
06/04/1972	V-WORLD BOND	21,000	CRUDE OIL
01/10/1973	P-TRANS-MOUNTAIN PIPELINE	460,000	CRUDE OIL
01/01/1978	V-BARGE	100,000	DIESEL FUEL
12/31/1980	F-WHATCOM CREEK PENTA SPILL	20,000	OTHER OIL
05/01/1981	V-ST. ANTHONY	2,000	CRUDE OIL
09/23/1983	P-OLYMPIC PIPELINE	168,000	DIESEL FUEL
03/20/1984	V-SS MOBIL OIL TANKER SPILL	200,000	HEAVY FUEL OIL
11/28/1985	P-OLYMPIC PIPELINE	34,000	JET FUEL
12/20/1985	F-CHEVRON BULK STORAGE TERMINAL	1,440	HEAVY FUEL OIL
12/21/1985	V-ARCO ANCHORAGE	239,000	CRUDE OIL
01/31/1988	V-MCN#5 BARGE	70,000	HEAVY FUEL OIL
12/23/1988	V-NESTUCCA BARGE	231,000	HEAVY FUEL OIL
02/25/1990	F-MANCHESTER NAVAL SUPPLY DEPOT	70,000	DIESEL FUEL
03/27/1990	F-TEXACO REFINERY	130,000	DIESEL FUEL
07/14/1990	F-PNW TERMINALS	30,000	OIL OTHER, TALLOW
08/10/1990	F-CHEVRON RICHMOND BEACH PARK	176,000	OTHER OIL
11/17/1990	F-PNW TERMINALS TALLOW SPILL	200,000	OIL OTHER, TALLOW
01/06/1991	F-US OIL AND REFINING COMPANY	600,000	CRUDE OIL
01/15/1991	P-TRANS MOUNTAIN	3,025	OTHER OIL
02/22/1991	F-TEXACO REFINERY	210,000	CRUDE OIL
02/28/1991	V-HANJIN CONTAINER	210	DIESEL FUEL
07/22/1991	V-TENYO MARU	100,000	HEAVY FUEL OIL AND DIESEL
12/11/1991	P-TRANS MOUNTAIN PIPELINE	3,528	CRUDE OIL
03/07/1992	P-TRANS MOUNTAIN PIPELINE	2,100	CRUDE OIL
06/30/1992	V-SUN ROSE	850	HEAVY FUEL OIL
07/04/1992	T-TWIN CITY FOODS	100	DIESEL FUEL
07/17/1992	V-SAMSON TUG	70	GASOLINE
08/22/1992	F-WASHINGTON WATER POWER	370	DIESEL FUEL
10/11/1992	V-ARCTIC ALASKA	30	DIESEL FUEL
11/03/1992	P-CHEVRON PIPELINE	20,000	JET FUEL
12/15/1992	V-ARCTIC ALASKA FISHERIES	500	DIESEL FUEL
01/07/1993	V-ARCTIC ALASKA FISHERIES	800	DIESEL FUEL
03/02/1993	V-F/V ROVER	495	DIESEL/LUBE OIL
04/15/1993	V-USS CAMDEN	5,400	HEAVY FUEL OIL
04/25/1993	F-PORT OF PORT TOWNSEND	900	DIESEL FUEL
04/25/1993	V-NOSAC FOREST	6,260	HEAVY FUEL OIL
05/04/1993	V-DUTCHIE C	60	DIESEL FUEL
06/01/1993	F-PENINSULA FUEL	35	DIESEL FUEL
06/03/1993	V-M/V CENTRAL	3,000	HEAVY FUEL OIL
08/03/1993	V-GREAT PACIFIC	100	DIESEL FUEL
08/05/1993	V-F/V EXCELLENCE	2,995	DIESEL FUEL
08/05/1993	V-ARCTIC ALASKA	50	DIESEL FUEL
08/08/1993	PACIFIC N. OIL	80	HEAVY FUEL OIL
08/13/1993	V-F/V RADIO	360	LUBE OIL
09/06/1993	V-STORMY SEA	30	DIESEL FUEL
10/14/1993	V-TIDEWATER SPILL	3,295	DIESEL FUEL
10/15/1993	V-F/V ANELA	50	DIESEL FUEL
10/18/1993	F-US OIL	264,000	CRUDE OIL
11/23/1993	V-WA D.O.C.	25	DIESEL FUEL
11/25/1993	F-U.S. NAVY	560	DIESEL FUEL
12/22/1993	V-USS NIMITZ	308	JET FUEL
01/07/1994	V-ISLAND TUG	40	DIESEL FUEL
01/10/1994	V-AN PING 6	2,771	HEAVY FUEL OIL
01/25/1994	F-FOSS MARITIME	300	DIESEL FUEL
01/30/1994	V-F/V TRIAL	40	DIESEL FUEL
02/01/1994	V-USS CAMDEN	30	DIESEL FUEL
02/15/1994	V-TUG DAUB	483	DIESEL FUEL
02/15/1994	F-NORTHWEST ENVIRO SERVICES	5,500	DIESEL FUEL

Incident Date	Incident Name	Total Quantity Spilled (Gallons)	Product Type
05/10/1994	V-GOLDEN DAWN	85	DIESEL FUEL
06/06/1994	V-USS SACRAMENTO	200	DIESEL FUEL
06/14/1994	V-MATTHEW	50	GASOLINE
06/29/1994	F-L.U. DRYDOCK	1,000	DIESEL FUEL
07/18/1994	V-JOE C	700	DIESEL FUEL
08/09/1994	V-USS ARCADIA	325	DIESEL FUEL
09/11/1994	V-OMAR	200	LUBE OIL
09/22/1994	V-J. MICHELLE	100	HYDRAULIC OIL
10/15/1994	V-TYSON SEAFOOD	25	DIESEL FUEL
10/15/1994	V-BRENEVA	500	DIESEL FUEL
10/27/1994	V-USS SACREMENTO	3,700	JET FUEL
11/05/1994	V-F/V SITKOF	100	DIESEL FUEL
11/13/1994	V-NOAA	80	DIESEL FUEL
12/17/1994	V- JUPITER	50	DIESEL FUEL
12/31/1994	V-CROWLEY BARGE 101	26,900	DIESEL FUEL
01/11/1995	F-BAINTER RANCH	300	DIESEL FUEL
01/20/1995	V-POLAR CUB	200	DIESEL FUEL
01/25/1995	V-U.S. NAVY	2,520	JET FUEL
01/25/1995	F-JOHNSON CONTROL	50	HYDRAULIC OIL
01/26/1995	V-TRIPOLI	30	DIESEL FUEL
01/27/1995	F-WEYERHAEUSER, LONGVIEW BUNKER SP	1,000	HEAVY FUEL OIL
01/30/1995	V-DAPHNE	400	DIESEL FUEL
02/10/1995	V-IMCO CONST.	37	DIESEL FUEL
02/17/1995	V-NX PRESSION	250	DIESEL FUEL
02/20/1995	TACOMA SCHOOL DISTRICT	50	HEAVY FUEL OIL
02/23/1995	V-CATHERINE	200	DIESEL FUEL
02/26/1995	V-USS-NIMITZ	100	DIESEL FUEL
04/22/1995	V-MARTINIQUE	55	DIESEL FUEL
05/24/1995	V-A. KOLLONTOY	100	DIESEL FUEL
06/02/1995	V-N. VICTOR	30	DIESEL FUEL
07/16/1995	V-BETTY JEAN	25	DIESEL FUEL
07/18/1995	V-RYBAKCAUTOKY	100	DIESEL FUEL
08/09/1995	V-GASTELLO	50	HEAVY FUEL OIL
08/13/1995	F-DISTINCTIVE PROPERTIES	30	DIESEL FUEL
08/19/1995	V-PELICAN	40	GASOLINE
09/14/1995	V-DAVID R. RAY	50	DIESEL FUEL
09/14/1995	V-SEA NEST	75	DIESEL FUEL
09/29/1995	V-DIANE	50	DIESEL FUEL
10/21/1995	F-SR 509 'D' STREET POND	50	HEAVY FUEL OIL
10/31/1995	F-TOSCO	85	CRUDE OIL
11/12/1995	V-OMAR	120	DIESEL FUEL
01/04/1996	V-MUSKRAT	30	HYDRAULIC OIL
01/05/1996	V-COMMODORE	241	DIESEL FUEL
01/06/1996	F-U.S. OIL	25	CRUDE OIL
01/14/1996	F-SNOQUALMIE PASS OIL TANK	200	HOME HEATING FUEL
02/06/1996	V-TANKER NEPTUNE	378	DIESEL FUEL
02/21/1996	V-REBEL	50	DIESEL FUEL
02/28/1996	V-BERNERT BARGE	308	DIESEL FUEL
03/23/1996	P-OLYMPIC PIPELINE	1,561	DIESEL FUEL
03/25/1996	V-NORTHERN LADY	450	DIESEL FUEL
04/16/1996	V-POLAR QUEEN	37	DIESEL FUEL
04/20/1996	T-WIND RIVER TRAIN DERAILMENT	65,000	DIESEL FUEL
04/21/1996	F-ROCK ISLAND SPILL	700	OTHER OIL
04/22/1996	V-ISSWAT	35	DIESEL FUEL
05/06/1996	F-WAPATO RANCH	4,000	HOME HEATING FUEL
05/15/1996	V-EXPEDITIONS 3	100	DIESEL FUEL
06/11/1996	V-U.S. NAVY	70	JET FUEL
06/17/1996	P-OLYMPIC PIPELINE	1,500	DIESEL FUEL
12/06/1996	F-GATX HARBOR ISLAND	49,000	GASOLINE, UNLEADED

This table lists all spills analyzed in this report. Also included are additional spills which included non-petroleum products or for which agency data is incomplete.

Appendix 4 — Legend for Map: Spills Over 10,000 Gallons

(Ranked by spill size)

	Incident Date	Incident Name	Total Quantity Spilled (Gallons)	Product Type
1	01/01/1972	V-GENERAL M.C. MEIGGS	2,300,000	HEAVY FUEL OIL
2	03/10/1964	V-UNITED TRANSPORTATION BARGE*	1,200,000	DIESEL FUEL
3	01/06/1991	F-US OIL AND REFINING COMPANY	600,000	CRUDE OIL
4	01/10/1973	P-TRANS-MOUNTAIN PIPELINE	460,000	CRUDE OIL
5	10/18/1993	F-US OIL	264,000	CRUDE OIL
6	12/21/1985	V-ARCO ANCHORAGE	239,000	CRUDE OIL
7	12/23/1988	V-NESTUCCA BARGE	231,000	HEAVY FUEL OIL
8	04/26/1971	V-UNITED TRANSPORTATION BARGE # U	230,000	DIESEL FUEL
9	02/22/1991	F-TEXACO REFINERY	210,000	CRUDE OIL
10	01/17/1990	F-PNW TERMINALS TALLOW SPILL**	200,000	OIL OTHER, TALLOW
11	03/20/1984	V-SS MOBIL OIL TANKER SPILL	200,000	HEAVY FUEL OIL
12	08/10/1990	F-CHEVRON RICHMOND BEACH PARK	176,000	OTHER OIL
13	09/23/1983	P-OLYMPIC PIPELINE	168,000	DIESEL FUEL
14	03/27/1990	F-TEXACO REFINERY	130,000	DIESEL FUEL
15	07/22/1991	V-TENYO MARU	+100,000	HEAVY FUEL, OIL & DIESEL
16	01/01/1978	V-COLUMBIA RIVER BARGE***	100,000	DIESEL FUEL
17	02/25/1990	F-MANCHESTER NAVAL SUPPLY DEPOT	70,000	DIESEL FUEL
18	01/31/1988	V-MCN#5 BARGE	70,000	HEAVY FUEL OIL
19	05/08/1986	P-OLYMPIC PIPELINE	70,000	OTHER OIL
20	04/20/1996	T-WIND RIVER TRAIN DERAILMENT****	65,000	DIESEL FUEL
21	12/06/1996	F-GATX HARBOR ISLAND	49,000	GASOLINE, UNLEADED
22	11/28/1985	P-OLYMPIC PIPELINE	34,000	JET FUEL
23	07/14/1990	F-PNW TERMINALS**	30,000	OIL OTHER, TALLOW
24	12/31/1994	V-CROWLEY BARGE 101	26,900	DIESEL FUEL
25	06/04/1972	V-WORLD BOND	21,000	CRUDE OIL
26	11/03/1992	P-CHEVRON PIPELINE	20,000	JET FUEL
27	12/31/1980	F-WHATCOM CREEK PENTA SPILL	20,000	OTHER OIL
28	04/27/1980	V-WILLAPA BAY SPILL***	20,000	OTHER OIL
29	04/23/1974	P-TRANS MOUNTAIN PIPELINE	16,128	CRUDE OIL
30	06/24/1990	V-SULAK	15,000	DIESEL FUEL
31	02/07/1990	P-OLYMPIC PIPELINE	12,600	DIESEL FUEL
32	08/12/1988	F-NAS WHIDBEY ISLAND	11,000	JET FUEL
33	01/01/1991	T-MONITOR TANKER*****	10,000	GASOLINE
34	03/28/1990	F-U.S. NAVY SUPPLY CENTER	10,000	DIESEL FUEL

V = Vessel spill
P = Transmission pipeline spill
F = Facility spill

+ The Tenyo Maru contained over 400,000 gallons when it sank, at least 100,000 gallons was released during the initial incident.

The following spills were not included in the report analysis because:

- ***** the spill occurred prior to 1970.
- ** this was a non-petroleum spill.
- ******* there is inadequate spill information.
- ******** this was a land transport spill; considerably less than 65,000 gallons was actually released.
- ********* this was a land transport spill.

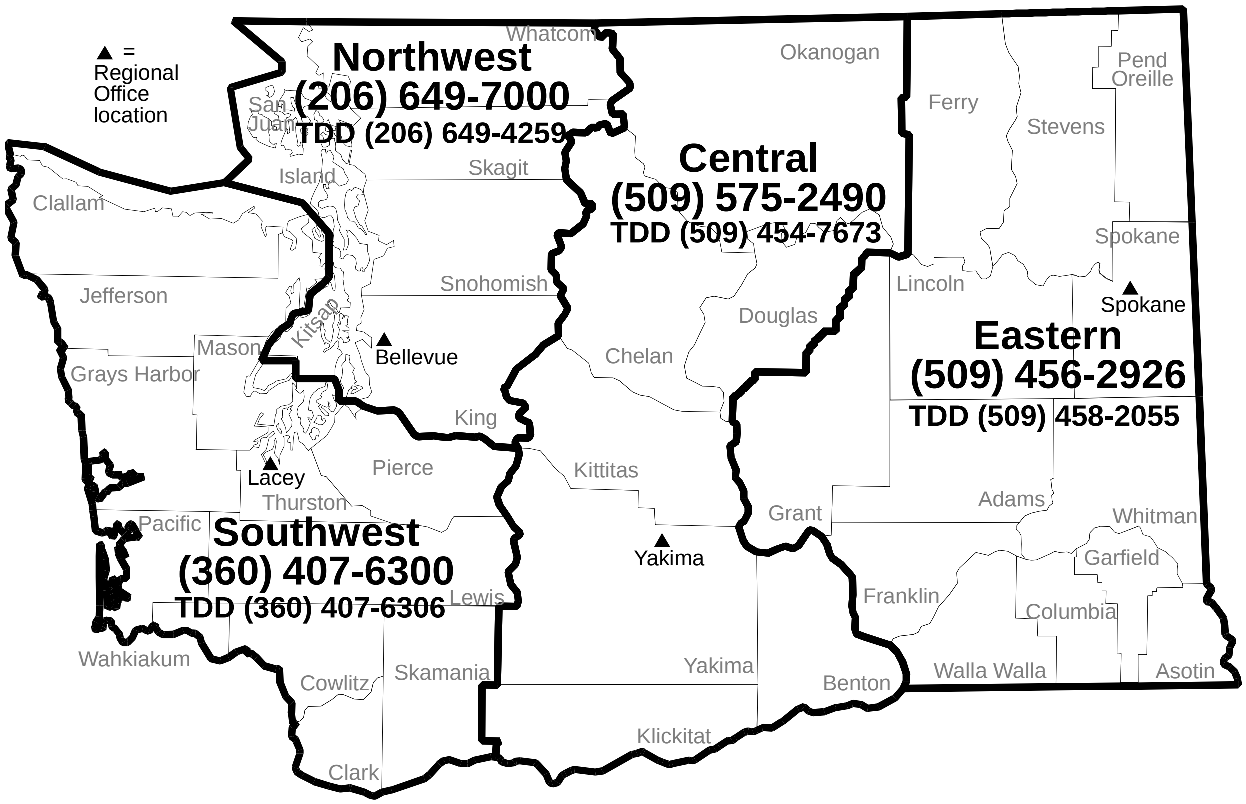
Other major spills will be added to this list as more information becomes available. Additional major spills have occurred at Kalama Chemicals, the City of Tacoma's power plant, US Oil in Tacoma, and on Whidby Island from an unknown source.

Appendix 5 — Ecology's Regional Offices

Washington Department of Ecology

Regional Office 24-Hour Oil and Hazardous Materials Spill Reporting Numbers

WASHINGTON STATE DEPARTMENT OF ECOLOGY



Need to Know:

- Reporting Party
- Contact Phone(s)
- Responsible Party
- Material Released
- Location
- Dead/Injured Fish or Wildlife
- Quantity
- Concentration
- Cleanup Status

Or call the state Emergency Management Division's 24-hour number at:

1-800-258-5990 or **1-800-OILS-911**

For EPA and U.S. Coast Guard reporting, call the National Response Center at:

1-800-424-8802

Emergency numbers for other states and federal agencies:

Idaho: Communications Center (208) 327-7422 *Oregon:* Emergency Management (503) 378-6377

EPA Region X, Seattle: (206) 553-1263 *British Columbia:* Provincial Emergency Program (800) 663-3456

THE OREGONIAN, available at
http://www.oregonlive.com/environment/index.ssf/2014/01/for_oil_trains_crossing_oregon.html

For oil trains crossing Oregon, Washington, state oversight gaps raise questions in wake of accidents

A fireball goes up at the site of a BNSF oil train derailment Dec. 30, 2013, near Casselton, N.D. The train carrying crude oil derailed, causing several explosions as some cars on the mile-long train caught fire. No fatalities were reported. Bruce Crummy/The Associated Press

By **Rob Davis | rdavis@oregonian.com**

on January 11, 2014 at 9:00 AM, updated February 13, 2014 at 10:05 AM

Ship crude oil on a tanker, barge or through a pipeline in Oregon and Washington, and you'd better get ready for paperwork.

It helps ensure state responders are ready for potentially catastrophic oil spills. You'll have to tell them where you're sending the oil. How much. What type it is. When you'll unload it.

Want to avoid the hassle? Just put the oil on a train.

With little public discussion, trains hauling potentially explosive crude oil are already passing near schools and through towns in Oregon and Washington, past parks and playgrounds. The oil is being transported under lighter state oversight than if it moved any other way.

In fact, oil trains are rolling through parts of the Pacific Northwest where large volumes of oil haven't moved before -- inland areas that haven't prepared for major oil spills.
In the last seven months, three high-profile explosions on trains in Canada and the United States have focused scrutiny on oil train safety. The worst, a July 6 derailment in Lac-Mégantic, Quebec, killed 47 people and leveled part of the town.

The two others, in North Dakota and Alabama, didn't kill anyone. In strokes of luck, both occurred in undeveloped areas. The blasts happened on rail lines owned by two companies, Burlington Northern Santa Fe and Genesee & Wyoming, that currently move crude oil through Portland, Vancouver, Wash., and to Port Westward near Clatskanie. More may come to a terminal proposed in Vancouver that could accept up to four oil trains a day.

Trains are a new way to move crude, the result of an oil boom in North Dakota. Without pipeline capacity, oil producers there have turned to railroads. But the North Dakota crude is different; it's extracted from underground rock formations and is more flammable than traditional crude. The rapid emergence of oil trains, from nearly none in 2008 to at least 110 through Portland last year, caught regulators flatfooted.

As officials in both states work to catch up, they're forced to depend on the voluntary cooperation of secretive railroad companies. Three railroads serving the Portland region refused to tell The Oregonian exactly where they're hauling crude oil locally. That information could alert neighborhoods in North Portland and Vancouver to risks in their backyards.

Regulators are in the dark, too. Though they say they're encouraged by cooperation from railroads after the July accident in Quebec, environmental officials in both states admit they aren't as ready as they could be for an oil train accident, in part because information is being shared slowly.

Here are six key shortcomings:

- The first firefighters on a scene won't always be able to control, or even attack, oil fires. Rural fire districts in both states have little of the special foam needed to extinguish oil fires. The cavalry could be an hour away or longer.

- State officials don't know where oil trains travel each day in Oregon and Washington. They don't know how many oil trains are here.
- Tankers and barges transporting oil products into Washington's coastal refineries and on the Columbia River have to tell the states where, when and what they move. Trains don't.
- Railroads maintain emergency caches of containment booms to prevent spills from spreading. But officials in both states don't know where. The Oregon Department of Environmental Quality doesn't know, for example, that Union Pacific keeps its emergency caches in Portland, while its trains carry crude throughout the Columbia River Gorge.
- Oregon and Washington regulators who keep the region ready for oil spills have not yet coordinated their emergency plans with railroads, which maintain separate response plans. That simple step could avoid wasting time in the key moments following an accident.
- Because of funding shortages, the Oregon Department of Environmental Quality is cutting back on oil spill training for employees. Though oil is increasingly coming through the region on trains, the state doesn't charge fees to railroads to fund preparedness like it does for ships carrying oil.

Railroad officials promised in November to share their emergency plans and cache locations with state officials in Oregon and Washington. But the information, some of which could be easily relayed by email, hasn't come. Another oil train has exploded since then.

"Where we're pretty uncomfortable is that it seems to be shrouded in mystery," said Linda Pilkey-Jarvis, one of the Washington Department of Ecology's top oil spill preparedness officials. "The fact that we don't have ready access to the plans doesn't lead to confidence."

♦♦♦

The accident was the worst rail fire Mike Greisen has seen in 38 years as a firefighter. It was May 2011. A log train derailed outside Scappoose, a small Columbia River town 30 minutes from Portland. A lopsided car dragged for two miles, ripping up the track as it went. It stopped after hitting a tanker filled with ethanol, basically grain alcohol, starting a fire that burned so hot firefighters eventually had to pull back a half-mile. Greisen and other fire officials say they got lucky. The accident didn't happen near homes or near drinking water.

But the incident was a stark reminder of the risks facing rural communities along Highway 30 between Portland and Clatskanie, a major corridor for the region's oil train traffic. Last year, about 7.7 million barrels of North Dakota crude traveled along those rails on tank cars like the one that held ethanol.

A crew from Greisen's department, the Scappoose Rural Fire Protection District, was the first on scene that spring day. But it wasn't equipped to fight a fuel fire. Firefighters counted on help arriving from Portland.

Greisen's crew needed a special type of foam to fight the fire – water makes it worse – and they didn't have very much. Rural fire stations often don't. Foam is expensive: $90 for enough to last two minutes.

Jay Tappan is chief of the nearby Columbia River Fire & Rescue, which protects towns like St. Helens and Rainier along the rail line carrying oil trains to Clatskanie. He says his crews have just 200 gallons of foam – not enough. (By contrast, the Port of Portland's firefighters, who must be ready for airplane fires, have access to 8,500 gallons.)

With oil trains increasing, Tappan wants more. He says he asked Genesee & Wyoming, the company that owns the rail line known as Portland & Western, for a trailer of foam and was promised he'd get it.

That was October. The trailer, which could cost $50,000, still hasn't come. A Genesee & Wyoming spokesman said the request happened during an "impromptu conversation" and offered no guarantee that his company would provide foam to Tappan's department.

The spokesman, Michael Williams, said by email that his company had agreed with the chief "to discuss and perhaps seek financial support through grants and/or from the railroad and shippers."

The railroad company called Tappan after The Oregonian's inquiry. "We spoke with him today and read him this answer, and he concurs," Williams said in an email.

The Oregonian did the same. Tappan didn't concur.

"They indicated it would be no problem," the fire chief said of the company's initial promise. "They were way open to a range of things they could do for us. It seemed like everything was possible then.

"It sounds like it might not happen as quickly as I want it to."

♦♦♦

Railroad companies willingly talk about their safety planning and culture.

They've trained hundreds of first responders throughout the region. Firefighters say that hands-on experience with full-sized model cars is invaluable. Railroads keep caches of emergency equipment at the ready for spills or fires. They tout their cooperation with local emergency officials.

But at the same time railroads discuss how they cut risk, they say less about how they're increasing it – or where.

It's a safety step, they say, instituted after Sept. 11, 2001. But in a region with an environmental community campaigning against oil trains, it's also a way to avoid local scrutiny and attention from communities bearing the risk.

You can piece together the exact routes of oil trains, but not from the companies operating them.

Here's what we know: Burlington Northern Santa Fe Corp. moves North Dakota crude along the Washington side of the Columbia River Gorge. (It won't acknowledge that it does.)

Oil trains exit the gorge, transit urban Vancouver and the Columbia River on a rail bridge just west of Interstate 5. They cross Hayden Island, neighborhoods in North Portland, the Willamette River and head north toward Clatskanie.

Union Pacific trains hauling a few interspersed cars of crude from Utah and Canada move on the Oregon side of the gorge and then into Portland. They also pass through Portland along the Interstate 5 corridor.

Last year, 110 trains each carrying 70,000 barrels of crude oil passed through Portland en route to Port Westward near Clatskanie. More could be on the way. The Port Westward facility can expand to 38 oil trains a month and another facility proposed in Vancouver could accept up to four oil trains a day.

The good news about those routes: Oil readiness officials in Oregon say they've prepared for oil spills along the Columbia River. Their challenge is that oil trains are plying new routes through inland communities.

"We have the water side pretty well drilled and understand what we need to do," said Bruce Gilles, who manages the Oregon Department of Environmental Quality's oil spill program. "Where we're a bit behind is developing our response plans for inland areas."

♦♦♦

Given today's focus on oil train safety, the railroad industry knows it has two options: Change, or be changed.

Industry officials have volunteered to phase out the type of tank car that's been involved in the three major oil train accidents and the May 2011 Scappoose accident.

But change has been slow. Though industry standards were tightened in 2011, the majority of tank cars used today still don't meet them. The construction of those tank cars was first identified as a danger in 1991 because they can easily rupture in accidents.

"We are continuing to look for more ways to enhance safety," said Holly Arthur, spokeswoman for the Association of American Railroads, an industry group.

Federal legislators are adding pressure. Oregon Senator Ron Wyden and U.S. Rep. Peter DeFazio – both Democrats – have called for investigations and hearings.

“The train derailment in North Dakota should be a wake-up call,” DeFazio said in a statement. “Congress needs to exert oversight and make sure action is taken to protect the American public.”

Though railroads are subject to federal regulation, Pilkey-Jarvis, the Washington oil spill official, said she worries that federal rules are more lax than what states could offer. She compares today’s oil train regulations with oil tankers before the Exxon Valdez: Risks were known, but planning wasn’t very good.

“What we’ve been finding from the Federal Railway Administration is that it’s a real passive way of regulating,” Pilkey-Jarvis said. “They don’t have standards. It’s sort of self-regulation.”

Asked about crude oil train explosions and the role of state oversight, a spokesman for the Federal Railway Administration, which has been slow to adopt safety standards to improve oil tank cars, sent this statement: “Rail safety is a national priority and 2012 was the safest year in the industry’s history.”

That was a year before the oil train explosions happened.

♦♦♦

Rainier Mayor Jerry Cole is a measured man. He’s a firefighter who grew up three miles from a nuclear power plant. Chicken Little arguments don’t faze him, he says. The sky isn’t falling.

The rail line in his small town, northwest of Portland on Highway 30, runs straight down a main street. Cars can drive across any part of the tracks that brought more than 100 oil trains through last year.

Of the three big oil train accidents last year, only one happened in a city. It was a small Quebec town, not unlike tiny Rainier. It’s not hard for the mayor to imagine just how catastrophic that type of accident would be for his town of 1,900.

Cole doesn’t have a lot of worries. But oil trains are one of them. He’s started wondering what railroads and the state government could do to address safety. More trains carrying oil mean more profit for someone else, he says, while Rainier gets stuck with the risk.

After the Quebec derailment killed 47 people in July, Cole recalls rail companies saying it was an isolated incident, something that never happens.

“Since that Canadian one, there’s been two more,” Cole says. “It does happen. It’s a concern.”

CBC NEWS: POLITICS, available at http://www.cbc.ca/news/politics/enbridge-s-kalamazoo-cleanup-dredges-up-3-year-old-oil-spill-1.1327268

Enbridge's Kalamazoo cleanup dredges up 3-year-old oil spill

Residents near massive oil spill differ on how Enbridge has dealt with the mess

By Max Paris Environmental Unit, CBC News Posted: Sep 06, 2013 10:35 AM ET Last Updated: Sep 13, 2013 12:50 PM ET

Enbridge oil spill still a mess 3:47

Three years after an Enbridge pipeline ruptured and spilled 3.3 million litres of oil into Michigan's Kalamazoo River, the company is still cleaning up and learning lessons about the way diluted bitumen behaves in fresh water.
The biggest lesson, simply put, is that bitumen sinks.

"Everybody learned from this incident about what we can do differently. Every one of us, from the regulators, to the contractors, to ourselves, have come away from this saying, 'I know what I would do differently the next time,'" explained Leon Zupan, Enbridge's chief operating officer.

The U.S. Environmental Protection Agency has ordered Canada's largest pipeline company to return to the river to dredge areas where the agency believes remains of the heavy bitumen fossil fuel have collected. The March 2013 order came nine months after most of the 56-kilometre stretch of the river affected by the spill was reopened to the public.

The Kalamazoo incident is the largest onland spill in the history of the U.S., and has already cost Enbridge more than $1 billion.

The 2010 Enbridge pipeline spill leaked 3.3 million litres of bitumin crude into the Kalamazoo River in Michigan. (Google/CBC)

The EPA believes there is at least 684,000 litres of bitumen still in the river. Before March's cleanup order was issued, Enbridge and the EPA went back and forth over how much oil there was and whether or not dredging it would do more harm than good to the Kalamazoo's ecosystem.

In the end, the EPA prevailed.

"They [Enbridge] don't agree with the way we develop our number. And, you know what, we're the agency and I'm not going to let them dictate how we do science," said Jeff Kimble, the EPA's incident commander in Marshall, Mich.

Bitumen sinks in fresh water

Scientific differences aside, the company agreed to the regulator's demand and began its work in August. For Enbridge and the EPA, the main lesson from the last three years is the need to recover the diluted bitumen, or dilbit, as soon as possible.

"If you know up front that you're dealing with an oil that has the potential to sink, attack it right away and get it off the surface while you can," explained Kimble.

Enbridge agrees. "If you can err in doing some damage to get the oil out sooner, then the long-term impacts are greatly mitigated," said Zupan.
For Enbridge, though, the Kalamazoo experience changed more than just the way it responds to emergencies. Zupan said the company's whole culture around safety is now different.

"We've redefined what's important to the company. We've added to our practices and procedures. We thought we were pretty good. We want to be the best," Zupan told CBC News.

But some in the area of the spill aren't buying that. Deb Miller of Ceresco, Mich., just down the road from Marshall, doesn't trust anything she hears from Enbridge or the EPA.

Jeff Kimble, an incident commander for the U.S. Environmental Protection Agency, next to the Kalamazoo River near the village of Ceresco, Mich. (Sat Nandlall/CBC News)

"I was absolutely naive going into this. I probably trusted more than I should have. I took things at face value that I should have never," explained Miller.

Miller's house backs on to the Kalamazoo River. When the spill happened, she was undergoing chemotherapy and her doctor ordered her to stay inside to escape the asphalt-scented fumes that permeated her village. From the beginning, she said, company and government officials have given conflicting and changing orders and advice.

"EPA has been very, very vocal in admitting the fact that they're writing the book as they go along on this spill," she said. But, she said, Enbridge is the real villain.

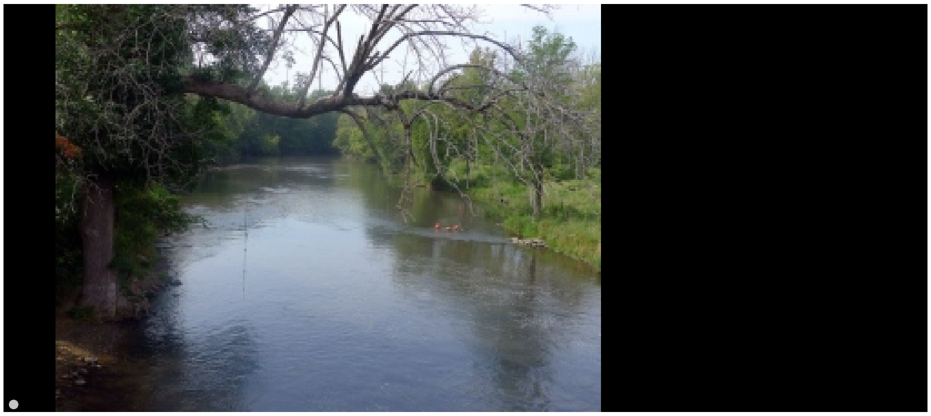
"Enbridge does what they have to do and only that," said Miller. She understands that the company is a for-profit business and that guides many of its decisions. But her life and town changed radically after the spill.

She and her husband had to shut down their carpet store. Enbridge bought the building but not the business. Many of her neighbours moved away. "When it affects people, residents — there's a high road and there's a low road. And unfortunately, I think they [Enbridge] found that low road."

Enbridge lived up to its promise

For Dr. Jim Dobbins, a retired family doctor and vice-president of a local conservation society in Marshall, that assessment of the company might be a little harsh. He admits he was sickened and angry as he watched the oil course under the bridge that spans the Kalamazoo just west of town. But when then Enbridge CEO Pat Daniel addressed a community meeting in Marshall soon after the spill, he decided to give the company a chance.

"[Daniel] said, 'We've made a mess and we're going to clean it up,'" recounted Dobbins. He admits to being pleasantly surprised.



"I'm not angry at the company," said Dobbins, although he is rankled by the spill.

"But generally, it appears as though they have done what they said they would do. And that is clean up the river."

He also thinks the EPA has gone too far with this latest order to re-dredge the river.

"I'm very concerned about them doing more damage to the river than [they] are good by retrieving that amount of oil that's left," said Dobbins. He thinks it is all about the EPA throwing its weight around rather than worry over the Kalamazoo's ecosystem.

Kimble explained it differently.

"You know, bottom line for EPA is under our authority this is oil that's causing a sheen or a release on a navigable waterway. Our authority says and our law says, get it out of the system."

That is precisely what Enbridge is doing. And, like everyone else involved in this incident, hoping to learn something in the process.

"The legacy for us is not that you can clean up a major oil spill after it occurs even though the river looks great today. The legacy for us is how do you make sure it never happens again," said Zupan.

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION V
POLLUTION/SITUATION REPORT #198

KALAMAZOO RIVER/ENBRIDGE SPILL – REMOVAL
SITE # Z5JS
MARSHALL, MICHIGAN
LATITUDE: 42.2395273; LONGITUDE: -84.9662018

Ceresco Pilot Channel Overview (01/29/2014)

To: Susan Hedman, U.S. EPA Regional Administrator
James Sygo, MDEQ
Michelle DeLong, MDEQ
Dr. Linda Dykema, MDCH
Deb Cardiff, Kalamazoo County Public Health
Richard Fuller**,** Kalamazoo County Sheriff's Office
James Rutherford, Calhoun County Public Health Department
Durk Dunham, Calhoun County Emergency Management
Scott Corbin, Allegan County Emergency Management
Tiffany Eichorst, City of Battle Creek
Cheryl Vosburg, City of Marshall
Christine Kosmowski, Calhoun County Water Resources Commissioner

From: Jeffrey Kimble, U.S. EPA, Federal On-Scene Coordinator

Date: 02/19/2014

Operational Period: 0700 hours 01/20/2014 through 0700 hours 01/27/2014
0700 hours 01/27/2014 through 0700 hours 02/03/2014

Reporting Period: 0700 hours 01/20/2014 through 0700 hours 02/03/2014

1. Site Data

Site Number:	Z5JS	**Response Type:**	Emergency
Response Authority:	OPA	**Incident Category:**	Removal Action
Response Lead:	RP	**NPL Status:**	Non-NPL
Mobilization Date:	7/26/2010	**Start Date:**	7/26/2010
FPN#:	E10527		

2. Operations Section

- The organizational response structure consisted of the following Branches: 1) Environmental Field Teams; and 2) Dredge Operations.

2.1 Environmental Field Teams Branch

2.1.1 Science Division

- No activities were performed during this reporting period.

2.1.2 Water Operations Division

- Management of oil sheen and/or globules continued throughout the period. No responses were conducted during this reporting period.

2.1.3 Compliance Division

- As of the close of the reporting period, Enbridge's MDEQ Ceresco Dam removal permit is in review with MDEQ. The public comment period closed on January 24, 2014.

2.2 Dredge Operations Branch

2.2.1 Ceresco, Mill Ponds, Morrow Lake and Sediment Trap Divisions

- Dredging operations at the Mill Ponds impoundment and the MP 36.1 sediment trap remained suspended throughout the reporting period due to icing conditions.
- Sediment removal from the MP 26.0 RDB sediment trap via Toyo pump suction dredging was conducted from January 20 – 23, 2014. Dredging operations were suspended on January 24, 2014 due to winter weather conditions. River ice conditions and safety concerns prevented the completion of dredging at several points. Demobilization of the site was conducted from January 24 – 31, 2014. U.S. EPA considers the MP 26.0 RDB sediment trap dredging work substantially complete as outlined in the Approved Work Plan.
- On January 21, 2013 U.S. EPA met with Enbridge to discuss plans and status of options for continued sediment removal actions at Morrow Lake and Morrow Lake Delta as required by the March 14, 2013 Order.
- Table 1 presents the quantities of water treated at each dredge location during the reporting period. Table 2 presents the estimated dredge waste on-site in Geotube bags, the cumulative estimated dredge waste (cubic yards), and the cumulative waste shipped off-site for disposal (tons).
- Work area air monitoring, dissolved oxygen water quality monitoring, and turbidity water quality monitoring were conducted during dredging activities.

2.2.2 Waste Management Division

- Cumulative quantities of soil, debris, and liquid shipped off-site during the response are presented in Tables 3 and 4.
- The cumulative quantity of recovered oil has been estimated using actual waste stream volumes, analytical data, and physical parameters of oil-containing media. A summary of the estimated volume of recovered oil is presented in Table 5.

3. Planning Section

3.1 Situation Unit

- During the reporting period, overflights were conducted on January 21 and 29, 2014 to document all operational areas and locations of oil sheen and/or globules. Photographs were taken and distributed to project participants in a Situation Update photograph log and during the Consolidated ICS Meeting.

3.2 Environmental Unit

- U.S. EPA, USGS, and the U.S. Army Corps of Engineers held weekly meetings to discuss Hydrodynamic Model (HDM) activities.
- U.S. EPA and USGS compiled summary figures and a written description of preliminary HDM results for the Morrow Delta and Morrow Lake drawdown scenarios and other recovery options for review by the Michigan Department of Natural Resources, U.S. Fish and Wildlife Service, and Enbridge.
- U.S. EPA continued review of oil fingerprinting analytical results from sheen and globule samples collected by Enbridge to determine the presence/absence of Line 6B oil.

3.3 Documentation Unit

- The Documentation Unit continued organizing and archiving electronic and paper files for post-incident use.

3.4 Resource Unit

- The Resources Unit continued to support production of the Incident Action Plan (IAP), supported the planning efforts of operations, and provided information to Logistics personnel in order to properly prepare and procure resources.

4. Command

4.1 Safety Officers

- Enbridge safety personnel continued conducting work-site safety inspections and implementing the plan for integration of public safety and worker safety on the Kalamazoo River.
- The USCG is providing the U.S. EPA with on-site support by monitoring safety throughout all active work areas.

4.2 Public Information

- The number of public inquires reported by Enbridge for this period is presented in Table 7.

5. Finance

- The current National Pollution Funds Center (NPFC) ceiling is $63.25 million. Approximately 94.4% of the ceiling has been spent through February 2, 2014. The latest average 14-day burn rate was $14,134 per day. These cost summaries reflect only U.S. EPA-funded expenditures for the incident. A summary of these expenses is presented in Table 8.

6. Scientific Support Coordination Group (SSCG)

- No activities were conducted during this operational period.

7. Participating Entities

- U.S. EPA and MDEQ continued to meet bi-weekly with a group of stakeholders to discuss how to continue to effectively communicate, share information about site progress, and receive feedback about the communication needs of the local communities. During this reporting period, the Stakeholder group met on January 23, 2014.
- For a list of cooperating and assisting agencies, see SITREP #51 (Sections 3.2 and 3.3).

8. Personnel On-Site

- Staffing numbers for the entities and agencies active in the response are presented in Table 9.

9. Source of Additional Information

- For additional information, refer to http://www.epa.gov/enbridgespill. For sampling analysis data, see http://response.enbridge.com/response/.

10. Clean-up Progress Metrics

Table 1 – Water Treated During Dredging Operations for the Reporting Period

Dredge Location	Water Treated (gal)
Ceresco	415,000
Mill Ponds	0
Sediment Traps	0
Morrow Lake	0

Table 2 – Dredging Waste (as of 02/03/2014)

Waste Stream	Estimated Dredge Waste On-Site in Geotube bags (yd^3)	Waste Transferred to Ceresco Dredge Pad (yd^3)	Cumulative Estimated Dredge Waste (yd^3)	Cumulative Waste Shipped Off-Site for Disposal (tons)
Ceresco Pad Total	2,345*	2,095	120,795	124,077
Mill Ponds	6,743	0	22,433	16,464
Sediment Traps	0	250	12,476	11,080
Morrow Lake Delta	0	0	1,982	544
C0.4/Wildlife Center/C3.2/FTC	N/A	0	904**	191
Total	**9,088**	**2,345***	**158,590**	**152,357**

*Estimate of Ceresco Pad waste includes waste from multiple sites as indicated.
**Estimated dredge waste related to oily debris.

Table 3 - Soil and Debris Shipped Off Site (as of 02/02/2014)

Waste Stream	Cumulative	Disposal Facility
Haz Soil (yd^3)	*19,644*	*Envirosafe (Oregon, OH)*
Non-Haz Soil (yd^3)	205,407	SET/C&C
Non-Haz Soil (yd^3)	4,436	SET/Ottawa County Farms
Non-Haz Soil (yd^3)	14,463	SET/WM Westside
Non-Haz Soil & Debris (yd^3) (Excluding 2010 Ceresco Dredge)	*64,815*	*Westside Recycling (Three Rivers, MI)*
Non-Haz Soil (yd^3) (2010 Ceresco Dredge Only)	*5,562*	*EQ/Republic (Marshall, MI)*
Haz Debris (yd^3)	*12,075*	*EQ/Michigan Disposal (Wayne, MI) and Republic (Marshall, MI)*
Non-Haz Household Debris (ton)	2,250	SET/C&C
Non-Haz Impacted Debris (ton)	13,734	

Shaded and italicized items are discontinued waste streams.

Table 4 - Liquid Shipped Off-Site (as of 02/02/2014)

Stream	Destination Company	Destination Location	Cumulative Volume (gallons)†
Non-Haz Water	Liquid Industrial Waste	Holland, MI	1,519,707
Non-Haz Water	Plummer	Kentwood, MI	851,989
Non-Haz Water	*Dynecol*	*Detroit, MI*	*981,792*
Non-Haz Water	*Battle Creek POTW*	*Battle Creek, MI*	*1,143,280*
Hazardous Water	*Dynecol*	*Detroit, MI*	*3,594,579*
Oil *Other Material*	*Enbridge Facility*	*Griffith, IN*	*766,288* *1,405,525*
Treated Non-Haz Water	*Liquid Industrial Waste*	*Holland, MI*	*370,200*
Treated Non-Haz Water	*Plummer*	*Kentwood, MI*	*4,976,140*
Hazardous Water	*Safety Kleen* [a]		*825*
Treated Non-Haz Water	*Dynecol*	*Detroit, MI*	*150,700*
Treated Non-Haz Water	*Battle Creek POTW*	*Battle Creek, MI*	*1,968,700*
		Total	**17,729,725**

Shaded and italicized items are discontinued waste streams.
† Cumulative quantities may not reconcile with previous reports (due to auditing).
a New Age lab water and methanol mix generated by mobile laboratory.

Table 5 – Estimated Recovered Oil (as of 02/03/2014)

Waste Stream Containing Recovered Oil	Destination Company	Destination Location	Estimated Oil Volume in Waste Stream (gallons)
Soil Impacted Soil & Debris	C&C Landfill	Marshall, MI	23,814*
	Envirosafe/ Westside RDF	Oregon, OH	278,665
Geotube Sediment - *(Impacted Sediment)*	*Envirosafe/ Westside RDF*	*Oregon, OH*	*1,298*
Debris - (Roll Off Boxes with Impacted Sorbents, boom, pads, plastic, PPE, vegetation, and biomass)	EQ Michigan	Belleville, MI	56,794*
Frac Tank City - *Influent to Carbon Filtration System*	*C&C Landfill*	*Marshall, MI*	*8,109*
Frac Tank City - Water	Dynecol	Detroit, MI	46,183
	Liquid Industrial Waste Services, Inc.	Kentwood, MI	
	Plummers Env. Inc.	Holland, MI	
	BC POTW	Battle Creek, MI	
Ceresco Pretreatment System	*C&C Landfill*	*Marshall, MI*	*90*
A-1 Pretreatment System	*C&C Landfill*	*Marshall, MI*	*9*
Oily Water - RPP	Enbridge Facility	Griffith, IN	766,288
		Total	**1,181,250**

Shaded and *italicized* items represent discontinued waste streams.
*Total updated for analytical received after report generation.

Table 6 – Samples Collected By Enbridge

Sample Type	Total	Feb. 2014	January 2014												
		1	31	30	29	28	27	26	25	24	23	22	21	20	19
Surface Water	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Private Well	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Groundwater	**56**	0	9	10	4	0	3	0	0	0	8	8	8	6	0
Sediment	**3**	0	0	0	0	1	2	0	0	0	0	0	0	0	0
Soil	**58**	0	5	8	3	4	4	0	0	3	5	8	11	7	0
Product	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dewatering	**4**	0	2	0	0	0	0	0	0	0	0	2	0	0	0
Sheen	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7 – Public Inquiries Received by Enbridge

Location/Med	January 2014													
	31	30	29	28	27	26	25	24	23	22	21	20	19	18
Marshall Community Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil Spill Public Information Hotline	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Website	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Public Inquiries	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 8 - Financial Summary (as of 02/02/2014)

Item		Expended (Cumulative)	
ERRS Contractors			
EQM (EPS50802)	*T057*	*$*	*1,199,522*
	T060	*$*	*213,636*
LATA (EPS50804)	*T019*	*$*	*1,161,082*
ER LLC (EPS50905)	*T040*	*$*	*683,330*
	Total ERRS Contractors	***$***	***3,257,571***
Other Contractors			
Lockheed Martin (EPW09031) – TAGA Support		*$*	*198,379*
Lockheed Martin (EPW09031) -Biodegradability Study			*61,886*
T&T Bisso (EPA:HS800008)		*$*	*882,087*
	Total Other Contractors	*$*	***1,142,352***
START Contractor – WESTON (EPS50604)			
	T030-Response	$	36,946,387
	Community Relations	$	114,563
	T032-Sampling	$	161,045
	T037-Doc Support		2,064,729
	Total START Contractor	**$**	**39,286,724**
	Response Contractor Sub-Totals	**$**	**43,693,319**
U.S. EPA Funded Costs: Total U.S. EPA Costs		$	**6,838,387**
Pollution Removal Funding Agreements Total Other Agencies		$	**3,637,081**
Indirect Cost (16.00%)		$	3,520,519
Indirect Cost (8.36%)-payments after 10/1/2011		$	1,310,859
Indirect Cost (10.15%)-payments after 10/1/2012		$	1,259,260
Cost Documentation/Billing Admin Fee (2.93%)*		$	597,311
	Total Est. Oil Spill Cost	**$**	**59,702,853**
Oil Spill Ceiling Authorized by USCG		$	**63,250,000**
Oil Spill Ceiling Available Balance**		$	**3,547,147**

Shaded and *italicized* items are discontinued
* Effective on EPA Enbridge costs billed to USCG for bills issued after 6/5/12.
**USCG personnel may increase to compensate for EPA not having all available funds to fully staff the site to execute the OPA Project Plan as approved through 12/31/2013. USCG personnel will fill gaps in contractor/EPA staff planned resources as appropriate.

Table 9 - Personnel On-Site

Agency/Entity	February 2014		January 2014											
	2	**1**	**31**	**30**	**29**	**28**	**27**	**26**	**25**	**24**	**23**	**22**	**21**	**20**
U.S. EPA	0	0	2	2	2	1	1	0	0	1	3	3	1	0
START	0	1	9	9	8	8	8	0	0	9	9	9	10	10
MDEQ	0	0	2	3	3	1	2	0	0	3	7	4	4	0
MDEQ Contractors	0	0	0	2	2	1	1	0	0	1	2	2	2	0
Other Agencies	0	2	3	3	3	1	2	0	0	4	3	0	0	2
Enbridge – Environmental Field Teams – Science*	0	4	11	13	18	17	13	3	4	16	18	17	20	17
Enbridge – Environmental Field Teams – Water Ops*	0	0	3	0	0	0	0	3	0	12	12	11	11	11
Enbridge – Dredge Operations – Ceresco*	7	39	44	53	53	24	42	19	12	50	50	56	54	50
Enbridge – Dredge Operations – Mill Ponds*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Enbridge – Dredge Operations – Delta/Morrow Lake*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Enbridge – Dredge Operations – Sediment Traps*	0	2	14	17	25	19	25	6	12	28	29	32	29	25
Enbridge – Waste Management*	0	52	60	63	13	3	2	0	4	88	86	86	83	78
Enbridge – Office Support*	9	17	45	46	36	36	37	5	17	36	39	39	40	35
Total	**16**	**117**	**193**	**211**	**163**	**111**	**133**	**36**	**49**	**248**	**258**	**259**	**254**	**228**

*Enbridge Operations and Field include Enbridge and contractors as reported by Enbridge