DISHONORABLE DISCHARGES:

HOW TO SHIFT COOK INLET'S OFFSHORE OIL & GAS OPERATIONS TO ZERO DISCHARGE

Lois N. Epstein, P.E.
Senior Engineer and Oil & Gas Industry Specialist

May 2006

COOK INLETKEEPER®

Protecting Alaska's Cook Inlet watershed and the life it sustains

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May 2006

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Ms. Epstein is a licensed Professional Engineer in the States of Alaska and Maryland and a member of the federal Office of Pipeline Safety's advisory committee on hazardous liquid pipelines. She has a masters degree from Stanford University in Civil Engineering with a specialization in environmental engineering and science, and undergraduate degrees from both Amherst College (in English) and MIT (in mechanical engineering). President Clinton nominated her in October 2000 to the Chemical Safety and Hazard Investigation Board, however the U.S. Senate did not vote on her nomination before the end of the 106th Congress.

About Cook Inletkeeper: Cook Inletkeeper is a community-based nonprofit organization dedicated to protecting Alaska's 47,000 square mile Cook Inlet watershed and the life it sustains, and a member of the national Waterkeeper Alliance. Cook Inletkeeper has offices in Homer and Anchorage. www.inletkeeper.org

Dishonorable Discharges: How to Shift Cook Inlet's Offshore Oil and Gas Operations to Zero Discharge

Table of Contents **Page**

Table of Contents **Page**

Tables

Figures

Dishonorable Discharges: How to Shift Cook Inlet's Offshore Oil and Gas Operations to Zero Discharge

Executive Summary

The sixteen offshore oil and gas drilling platforms located in upper Cook Inlet have produced over 1 billion barrels (nearly 45 billion gallons) of oil, over 3 trillion cubic feet of natural gas, over 1.1 billion barrels (over 48 billion gallons) of contaminated "produced water," and a significant quantity of contaminated drilling wastes from the mid-1960s through the end of 2005. In contrast to other coastal locations throughout the United States, nearly all the contaminated produced water and drilling wastes from these offshore oil and gas operations have been – and continue to be – discharged into marine waters despite the 1972 federal Clean Water Act goal of eliminating the discharge of pollutants into navigable waters. In other coastal locations around the country, "zero discharge" is the norm for offshore platforms. Because the U.S. Environmental Protection Agency (EPA) allows ongoing discharges into marine waters for the fifteen Cook Inlet platforms and their three related onshore facilities covered in the general discharge permit and in this report, Cook Inlet's offshore oil and gas producers receive an outdated and unwarranted federal economic subsidy that unnecessarily pollutes the Inlet.

Not all produced water generated by Cook Inlet offshore oil and gas operations is discharged into the marine environment *directly* from the platforms. Over 99.8% of the total produced water from Cook Inlet's offshore drilling operations is sent onshore to three facilities – with 96% going to just one facility at Trading Bay – where advanced treatment and/or zero discharge into a Class II disposal well would be easier than at the offshore platforms. Once onshore, the crude oil, natural gas, and produced water pumped up from underground are separated, and the produced water is discharged to Cook Inlet following minimal treatment. Produced water discharged into Cook Inlet from the offshore platforms in 2005 contained over 32,000 gallons of oil and grease, over 50,000 pounds of zinc and over 440 pounds of arsenic.

Despite that fact that oil and gas production in Cook Inlet is in decline and 1995 was the peak year for produced water generation, the <u>draft</u> Clean Water Act permit issued in March 2006 by EPA allows a 69% increase in the amount of produced water the offshore platforms can discharge. The draft permit allows a maximum annual discharge in produced water of over 100,000 gallons of oil and grease and nearly 887,000 lbs of metals such as mercury, nickel, copper, manganese and zinc.

This report provides a rationale for re-examining EPA's previous decisions – some based on limited information – allowing produced water and drilling wastes to be discharged into Cook Inlet's biologically-productive and economically-important coastal waters. The report recommends that EPA use updated economic, technologic, scientific, and Traditional Ecological Knowledge information to evaluate if zero discharge is warranted in the renewed Clean Water Act permit given known and projected, adverse, economic and environmental impacts on the Cook Inlet region should the discharges continue.

There are new, compelling reasons for EPA to require zero discharge in the <u>final</u> Clean Water Act permit, including changed industry economics and new waste management technologies and

facilities available within the Cook Inlet region. Additionally, continuing to allow discharges can cause cumulative harm from persistent toxic contaminants, can adversely affect the market for – and quality of – Cook Inlet commercial fish, and is unnecessary technologically.

With this report, Cook Inletkeeper hopes to stimulate dialogue among government regulators, industry, and the public on the full costs to society of Cook Inlet oil and gas production and how the following, significant, recent changes support EPA making a zero discharge decision in the final permit for these facilities. The report includes two zero discharge scenarios which are far less costly than those analyzed by EPA prior to issuance of the 1999 Clean Water Act permit for Cook Inlet's offshore platforms.

Economic Changes Since Permit Issuance in 1999

- The price of crude oil currently is at record levels and experts expect it to remain high. Oil prices in 2006 for Cook Inlet are 448% higher than they were in 1999 in constant dollars, and Cook Inlet oil producers covered by the Clean Water Act permit made nearly $59 million in profits in 2005 (assuming $10 per barrel profit at $50 per barrel oil, low compared to 2006 profits);
- When Cook Inlet crude oil was selling for less than $27 per barrel in 2003, the Alaska legislature reduced the royalties paid to the state by operators of Cook Inlet platforms producing less than 1,200-1,500 barrels of oil per day (four Cook Inlet platforms qualify);
- The state legislature likely soon will enact a tax credit for re-investment in Alaskan infrastructure;
- Aging Cook Inlet fields currently produce less oil and gas than in previous years, and platforms have been, and likely will continue to be, "shut-in" (i.e., the wells cease production) when they no longer produce sufficient oil or gas. This opens up the possibility of using the unused pipelines to transport produced water back to the shut-in platforms for injection; and,
- ConocoPhillips converted the Tyonek platform to zero discharge for its produced water in 2004 and Chevron/Unocal converted the Anna platform in 2005. Since beginning production in Cook Inlet in 2002, Forest Oil injects its platform's produced water and drilling wastes. Thus, for 3 of the 12 operating Cook Inlet platforms, managing produced water in this way has been demonstrated to be economically feasible.

Technology Changes Since Permit Issuance in 1999

- Improvements in "grind and inject" technologies for drilling wastes now can overcome the Cook Inlet injection well plugging problems that were a large part of the previous rationale for allowing drilling waste disposal directly into Cook Inlet; and,
- Marathon and Chevron/Unocal, both major operators in Cook Inlet, opened new grind and inject facilities for drilling wastes in the Cook Inlet region in 1999 and 2002, respectively.

Scientific Changes and Traditional Ecological Knowledge Evidence Since Permit Issuance in 1999

- New data from *Exxon Valdez* oil spill research on hydrocarbon effects on salmon show that far lower levels of contamination than previously recognized have adverse impacts;
- New EPA data collected on oil and gas contaminants in food and Traditional Ecological Knowledge on the quality/quantity of subsistence foods, respectively, argue against allowing additional toxic discharges into Cook Inlet; and
- The National Marine Fisheries Service (NMFS) classified Cook Inlet's beluga whales as a "depleted" stock of marine mammals under the Marine Mammal Protection Act in 2000. Because the Cook Inlet beluga whale population has not increased in recent years after sharp restrictions on Alaska Native subsistence hunting, NMFS currently is evaluating whether the whale should be classified as "threatened" or "endangered" under the Endangered Species Act.

These recent developments, taken together, make a compelling case for EPA to require zero discharge for Cook Inlet offshore oil and gas operations during Clean Water Act permit renewal.

Table ES-1 compares the reasons EPA used in its 1999 permit decision to allow discharges with current conditions in Cook Inlet. The current rationale for zero discharge is discussed in detail in Section VI of this report.

Table ES-1
Cook Inlet Discharge Comparison Between 1999 and the Present

Type of Discharge	Primary 1999 Rationale Allowing Discharges	Current Rationale for Zero Discharge
Produced water	Cost	High price of crude oil resulting in higher industry profits; royalty reductions; shut-in platforms and pipelines can be used for produced water injection instead of new pipeline construction; an injection well near Trading Bay Production Facility now may be feasible
Drilling waste	Lack of nearby facilities for disposal	Technological improvements have overcome injection problems; operators opened new disposal facilities

I. Introduction and Purpose

Offshore Southcentral Alaska – within view of homes on the hillsides above Anchorage – stand sixteen drilling platforms with over 580 oil and natural gas wells protruding from their foundations (see Figure 1). These wells are approximately 11,000 feet deep, and the oldest platforms and wells date from the mid-1960s. Through the end of 2005, the wells produced over 1 billion barrels of oil (nearly 45 billion gallons), over 3 trillion cubic feet of natural gas, over 1.1 billion barrels of contaminated "produced water" (over 48 billion gallons) and a significant quantity of contaminated drilling wastes.[1] Additionally, Cook Inlet offshore operators injected over 2.3 billion barrels of treated seawater (97 billion gallons) to maintain and enhance oil production in the underlying formations.

Cook Inlet operators (with the exception of Forest Oil and its Osprey platform[2] which is not included in this report unless otherwise noted) discharge nearly all of the contaminated produced water and drilling wastes generated from the offshore oil and gas platforms into Cook Inlet. The discharges occur following only minimal treatment (gas flotation) of the produced water and no treatment of the drilling wastes. In 2005, operators sent over 99.8% of the total produced water from Cook Inlet's offshore operations by pipeline to three onshore facilities – Trading Bay Production Facility, Granite Point Production Facility, and the East Foreland Treatment Facility – where they separated the crude oil, natural gas, and produced water and piped the still-contaminated produced water offshore for discharge.

Table 1 shows oil and gas field locations, ownership, ages, and status of existing Cook Inlet offshore platforms. The platforms are located in what the federal and state governments consider a "coastal" area since they are less than three nautical miles (almost 3.5 miles) offshore in state waters, and thus under state jurisdiction.

Produced water: "Produced water" is any water brought to the surface during oil and gas production including water containing oil from the geologic formation, injection water, and drilling additives. Generally briny, produced water typically contains pollutants such as oil and grease, acids, ammonia, benzene, naphthalene, metals (e.g., chromium, copper, lead, zinc), and sometimes radionuclides, following separation from crude oil and natural gas.

Drilling wastes - fluids, muds, and cuttings: "Drilling wastes" covers all these byproducts. "Drilling fluids" or "drilling muds" are the lubricating materials used in the rotary drilling of wells during well exploration and development (i.e., prior to production), which clean and condition well holes, lubricate the drill bit, transport drill cuttings to the surface, and maintain down-hole pressure to prevent well blowouts. Drilling fluids and muds are mixtures of water or oil with clay, metals (e.g., cadmium, mercury, and lead), and organics (e.g., alkylated benzenes, naphthalenes, phenanthrenes). "Drill cuttings" are small pieces of formation rock brought to the surface during drilling.

[1] Each Cook Inlet well generates approximately 30,000 barrels (1.26 mill. gallons) of drilling wastes (*Drilling Waste Disposal Alternatives: A Cook Inlet Perspective*, Marathon Oil Company and Unocal Corporation, March 1994, p. 6.)

[2] Forest Oil's Osprey platform, which is permitted individually under the Clean Water Act, began operations in Cook Inlet in 2002 after issuance of the 1999 Clean Water Act general discharge permit for all other Cook Inlet oil and gas platforms. Forest Oil's Osprey platform permit (U.S. EPA Permit Number AK-005330-9) requires zero discharge.

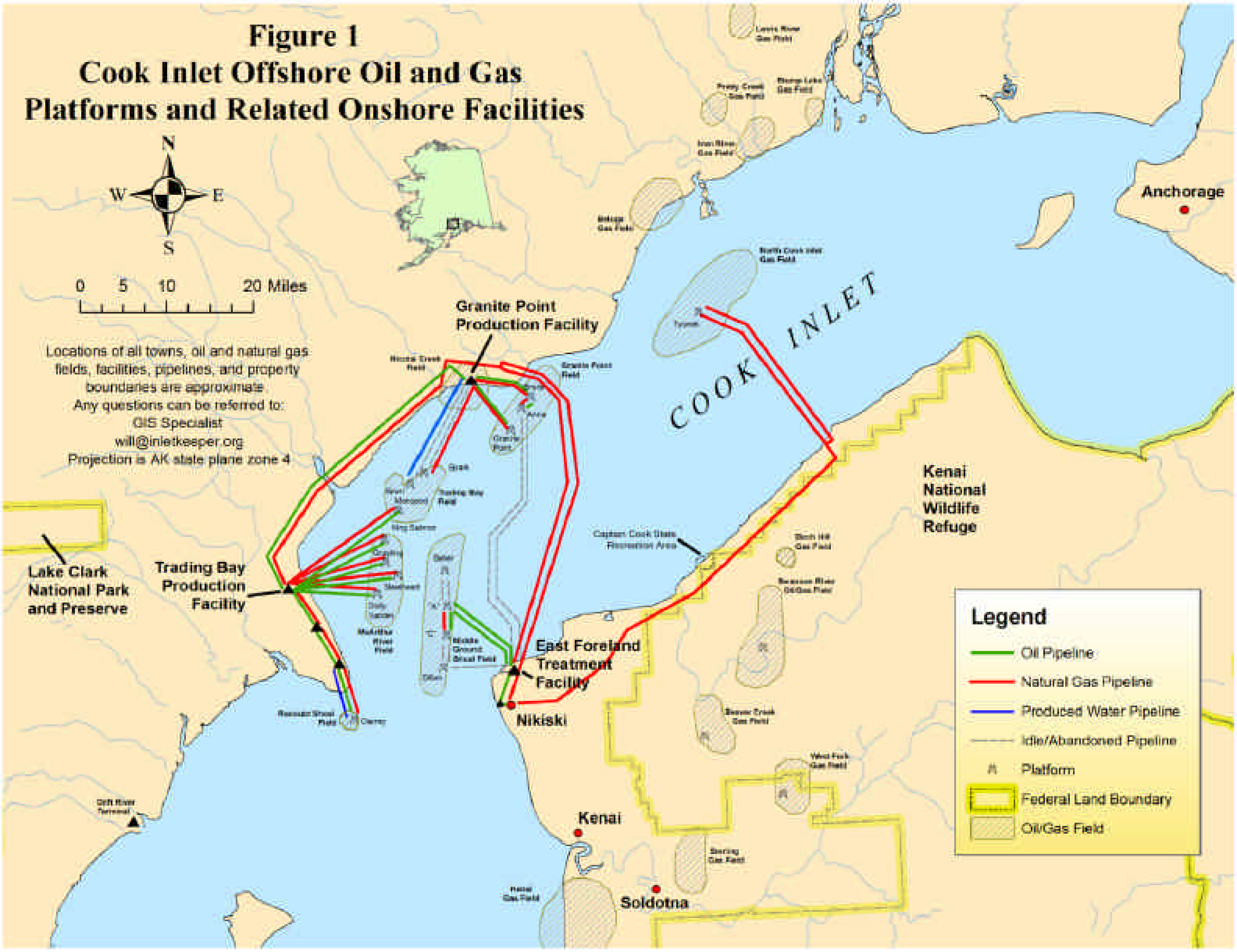
Figure 1
Cook Inlet Offshore Oil and Gas
Platforms and Related Onshore Facilities
N
W
E
S
0 5 10 20 Miles
Locations of all towns, oil and natural gas fields, facilities, pipelines, and property boundaries are approximate.
Any questions can be referred to:
GIS Specialist
will@inletkeeper.org
Projection is AK state plane zone 4
Granite Point Production Facility
COOK INLET
Anchorage
Kenai National Wildlife Refuge
Lake Clark National Park and Preserve
Trading Bay Production Facility
East Foreland Treatment Facility
Nikiski
Kenai
Soldotna
Legend
Oil Pipeline
Natural Gas Pipeline
Produced Water Pipeline
Idle/Abandoned Pipeline
Platform
Federal Land Boundary
Oil/Gas Field

Table 1
Cook Inlet Offshore Platform Information

Platform Name	Oil/Gas Field	Current Owner/Operator	Installation Date	Status
"A"	Middle Ground Shoal	XTO Energy	1964	Active
Anna	Granite Point	Chevron/Unocal	1966	Active
Baker	Middle Ground Shoal	Chevron/Unocal	1965	Shut-in* (2003)
Bruce	Granite Point	Chevron/Unocal	1966	Active
"C"	Middle Ground Shoal	XTO Energy	1967	Active
Dillon	Middle Ground Shoal	Chevron/Unocal	1966	Shut-in* (2003)
Dolly Varden	McArthur River	Chevron/Unocal	1967	Active
Granite Point	Granite Point	Chevron/Unocal	1966	Active
Grayling	McArthur River	Chevron/Unocal	1967	Active
King Salmon	McArthur River	Chevron/Unocal	1967	Active
Monopod	Trading Bay	Chevron/Unocal	1966	Active
Spark	Trading Bay	Marathon	1968	Injection only
Spurr	Trading Bay	Marathon	1968	Shut-in* (1993)
Steelhead	McArthur River	Chevron/Unocal	1986	Active
Tyonek	North Cook Inlet	Phillips	1968	Active (gas only)

** "Shut-in" means the platform's wells no longer produce oil or gas, nor are they used to inject wastes.*

Alaska's Cook Inlet is the only coastal area in the nation where produced water and drilling wastes can be released into marine waters. The 1999 Clean Water Act general[3] discharge permit for Cook Inlet's offshore oil and gas operations contains this U.S. Environmental Protection Agency (EPA) exemption (see Appendix 1 for the applicable regulation). In contrast, EPA does not allow discharge of produced water and drilling wastes in coastal areas in the Gulf of Mexico, off the coast of California, and elsewhere.

This report provides a rationale for re-examining EPA's earlier permit decision allowing produced water and drilling wastes to be discharged into Cook Inlet's biologically-productive and economically-important coastal waters. It now is appropriate for EPA to mandate requirements more protective of Cook Inlet's valuable marine environment because circumstances have changed significantly. Moreover, ongoing discharges pose the increased risk of cumulative harm to Cook Inlet's marine organisms.

II. Why Care?

Long after Cook Inlet's oil and gas resources are extracted, fishing, tourism and recreation, and subsistence will continue if the ecosystem remains healthy. A healthy Cook Inlet ecosystem also provides substantial jobs and revenue to Southcentral Alaska residents, approximately half the state's population.

[3] The permit is considered a "general" permit because it covers multiple facilities.

It is reasonable to ask why EPA created a coastal-area exemption for Cook Inlet's offshore drilling operations in the first place and why the exemption is a concern.

Background on the Cook Inlet exemption. As shown in Table 1, operators installed nearly all of Cook Inlet's offshore platforms in the late 1960s, prior to passage of the Clean Water Act in 1972. Cook Inlet's relatively old platforms were designed in an era before extensive discharge regulation, making it potentially more difficult and costly for the platforms to achieve the zero discharge norm. Congress recognized the importance of allowing for an orderly upgrading of facility infrastructure to meet the Clean Water Act discharge elimination goal[4] and designed the statute to encourage strengthening of discharge permits during the five-year permit renewals.

In 1999, EPA issued the Clean Water Act general discharge permit for Cook Inlet's fifteen offshore platforms (i.e., not including Osprey platform) and their three related onshore facilities[5] based on a previously-issued EPA technical and economic document known as the Effluent Limitations Guideline (ELG) for coastal oil and gas extraction operations.[6] ELGs contain technology-based discharge limits for all facilities in a particular industrial category, which then are incorporated into discharge permits nationwide. EPA issued the final ELG for coastal oil and gas extraction operations in 1996 and has not updated it since. In response to requests from several stakeholders to update the ELG in 2004, EPA stated it would not do so in part because the EPA permit writer could "require an operator to demonstrate that zero discharge is not technically feasible for a specific project."[7] EPA did not, however, require a demonstration of technical feasibility prior to development of the current draft general discharge permit.

The 1999 Clean Water Act permit for Cook Inlet offshore oil and gas operations expired on April 1, 2004 but has been extended until EPA issues a new permit, probably in 2006. The new permit can contain different permit conditions – including prohibiting discharges to Cook Inlet – so long as it is in compliance with the federal Clean Water Act. Prior to permit issuance in 1999, EPA's stated rationale for the Cook Inlet exemption was: "The EPA rejected zero discharge for muds & cuttings in large part because the technology of grinding and injection has not been demonstrated to be available throughout Cook Inlet. The EPA rejected zero discharge of produced water because zero discharge is not economically achievable in Cook Inlet."[8]

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[4] *See* 33 USC 1251(a)(1) which states that "it is the national goal that the discharge of pollutants into the navigable waters be eliminated by 1985." EPA reiterates this goal in the preamble to the final rule covering coastal oil and gas extraction point source discharges, 61 Federal Register 66088 (December 16, 1996).

[5] U.S. EPA Permit Number AKG-28-5000.

[6] *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, U.S. Environmental Protection Agency, EPA-821-R-96-023, October 1996.

[7] *Technical Support Document for the 2004 Effluent Guidelines Program Plan*, U.S. Environmental Protection Agency, EPA-821-R-04-014, p. 5-230 (for Drilling Fluids and Drill Cuttings) and p. 5-231 (for Produced Water), August 2004.

[8] Response to Comments Received on the Proposed Reissuance of the Cook Inlet General NPDES Permit, U.S. EPA, p. 14 (undated).

EPA issued the draft discharge permit in March 2006.[9] In the draft permit, the offshore platforms are permitted to discharge in their produced water over 100,000 gallons of oil and grease annually and nearly 887,000 lbs of metals such as mercury, nickel, copper, manganese and zinc.[10] The draft permit also allows nine Cook Inlet discharge locations, a significant increase from the four locations now discharging produced water (the current permit allows up to eight discharge locations).

As a result of the earlier ELG and permitting decisions, Cook Inlet's offshore oil and gas producers covered by the permit (i.e., Chevron/Unocal and XTO Energy[11]) do not pay the costs other companies with coastal offshore oil and gas operations in the U.S. pay to achieve zero discharge, i.e., conversion of platforms and wells so produced water and drilling wastes are injected. Additionally, these operators do not pay the true costs of production since they do not pay to discharge contaminants into public waters. When EPA allows operators to discharge pollution into Cook Inlet, that decision is a federal subsidy to Cook Inlet operators which – in turn – degrades the valuable Cook Inlet ecosystem.

<u>Who and what are affected by the Cook Inlet exemption</u>. Though Cook Inlet has relatively strong tides, at least some of the toxic pollutants discharged from drilling operations remain in Cook Inlet, dispersed and dissolved in the water column and adsorbed onto sediments.[12] Contamination near the platforms has not been measured, however. Marine organisms are exposed to these pollutants via consumption and/or dermally. Heavy metals are among the toxic discharges from offshore oil and gas operations that can persist in fish, shellfish, and marine mammals. Those who eat fish and shellfish from Cook Inlet may ingest some quantity of toxic pollutants from offshore oil and gas operations, though the lack of complete testing makes it difficult to know the full extent of the health impacts (see Section VI).

Cook Inlet is a world-renown fishery, prized for its salmon (especially red, king, and silver), halibut and other groundfish, herring, and shellfish.[13] The value of upper and lower Cook Inlet

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[9] National Pollutant Discharge Elimination System Permit No.: AKG-31-5000. *See* http://yosemite.epa.gov/r10/WATER.NSF/NPDES+Permits/DraftPermitsAK for the draft permit and related information (last visited on May 24, 2006).

[10] Calculations based on the draft permit's maximum projected discharge rates for produced water discharges by facility and facility-specific effluent limits. See *Fact Sheet, Oil and Gas Exploration, Development and Production Facilities Located in State and Federal Waters in Cook Inlet*, Permit Number AKG-31-5000, U.S. Environmental Protection Agency Region 10, February 23, 2006, Table 2 (p. 34) and Appendix B (pp. 69-73).

[11] ConocoPhillips and Marathon, which operate Cook Inlet platforms, currently do not discharge produced water into Cook Inlet.

[12] Tides move materials both into and out of upper Cook Inlet, where the platforms are located. The hydraulics of Cook Inlet are extremely complicated and not fully understood. Only a sufficient net current out of the area containing the discharges throughout the year would disperse all the toxic materials, and that is not the case because there is little or no flow into Cook Inlet from upper Cook Inlet rivers in winter

[13] *See* http://www.cf.adfg.state.ak.us/region2/finfish/salmon/uci/cookinlet.php (last visited on April 17, 2006).

commercial salmon was $33 million in 2005,[14] which does not include the value of sportfishing, Alaska Native subsistence, personal use fishing for Alaska residents not practicing subsistence, and non-salmon fisheries. The "Kenai Wild" brand of salmon from Cook Inlet has, in recent years, gained market-share outside of Alaska as a high-quality, valuable, wild Alaskan salmon product from presumably unpolluted waters.

One in eight private-sector jobs in Alaska is tourism-related, Alaska's fastest growing industry.[15] According to the state Chamber of Commerce, approximately 1.2 million visitors traveled to Alaska in 2002 and spent between $1200 and $1300 on average per visitor.[16] In 1993, the last year such data were collected, 67% of summer visitors to Alaska traveled in Southcentral Alaska including the Cook Inlet region.[17] Using these numbers, Southcentral Alaska received over $1 billion in summer revenue from tourism in 2002.

Native communities including Port Graham, Nanwalek, Chickaloon, Eklutna, Seldovia, Ninilchik, and Tyonek, members of the Kenaitze Tribe, and others depend on the Cook Inlet watershed's healthy waters and habitats for their livelihoods. These villages pursue a subsistence lifestyle that is centuries old, with wild, including marine, foods supplying a high percentage of villagers' diets. Because a higher percentage of their food supply comes from Cook Inlet-related sources than for most non-Native individuals, many of those living in these communities may be disproportionately impacted by toxic chemicals in their foods compared with non-Natives.

As part of the draft general discharge permit's Environmental Assessment, EPA "facilitated the collection of Traditional Ecological Knowledge (TEK) from Cook Inlet Area tribes."[18] While it is impossible to know if contaminants are the sole cause of the changes noted by Alaska Natives, EPA documented in its Fact Sheet for the draft permit that:

> Tribal members frequently noted an overall decline in the population of important food species being caught or harvested. These changes include salmon with thinner and less firm meat and smaller halibut with chalky and fibrous meat. In addition, Tribal members noted a disappearance in bull kelp and a decrease in the abundance of clams, cockles, bidarkis, cod, flounder, crab, shrimp, mussels, algae, seals and sea lions. Clams and mussels were observed to have thinner and sometimes transparent shells. Furthermore, Tribal members observed a higher incidence of red tide that has resulted in a decrease in the community's ability to collect traditional food, including shellfish and octopus.

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[14] Alaska Department of Fish and Game, Season Summaries, http://www.cf.adfg.state.ak.us/region2/finfish/salmon/salmhom2.php (last visited on May 9, 2006).

[15] *See* http://www.alaskachamber.com/artman/publish/tourism.html (last visited May 5, 2006).

[16] Ibid.

[17] *Recreation and Tourism in South-Central Alaska: Patterns and Prospects*, Steve Colt, Stephanie Martin, Jenna Mieren, and Martha Tomeo, prepared for the U.S. Forest Service, PNW-GTR-551, October 2002, p. 36.

[18] *Fact Sheet, Oil and Gas Exploration, Development and Production Facilities Located in State and Federal Waters in Cook Inlet*, Permit Number AKG-31-5000, U.S. Environmental Protection Agency Region 10, February 23, 2006, p. 47.

> Tribal members also observed a decrease in the number of sea ducks, such as mergansers and scoters. A number of Tribal members noted finding lesions, growths and deformities on fish. Some Tribal members noted that non-commercial fish, such as hooligans and sticklebacks, have declined in numbers; thus, indicating that commercial and recreational fishing are not the sole causes for the observed decline in population…
>
> The impact[s] on Tribes include traveling farther to collect food and the inability to obtain a sufficient quantity of traditional food. Since a significant portion of a Tribal member's diet consists of seafood from Cook Inlet, there is increasing concern regarding the impact on health from contaminants that may accumulate in seafood and the affect (sic) of eating lower quality fish. This fear has led some parents to stop feeding their children traditional foods.[19]

Last, the impact of the discharges on Cook Inlet's beluga whale population is unknown, but it may be significant. According to EPA, "The discharge of produced water may affect, but is not likely to adversely affect, all of the considered species *except* the Beluga whale…The Beluga whales, which frequent the upper Inlet, may be adversely affected by pollutants in produced water. This species may be affected either directly (through exposure) or indirectly (through ingestion and bioaccumulation) (Avanti 1992)" (emphasis in original).[20]

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[19] Ibid., pp. 48-9.

[20] *Cook Inlet (Reissuance) Fact Sheet*, September 7, 1995, p. 38. A recent EPA analysis which does not address the accumulation of persistent toxic chemicals, however, doubts the likelihood of adverse effects from the discharges on Cook Inlet's beluga whales despite the lack of recovery of the population in recent years. This study states – without backup documentation – that:

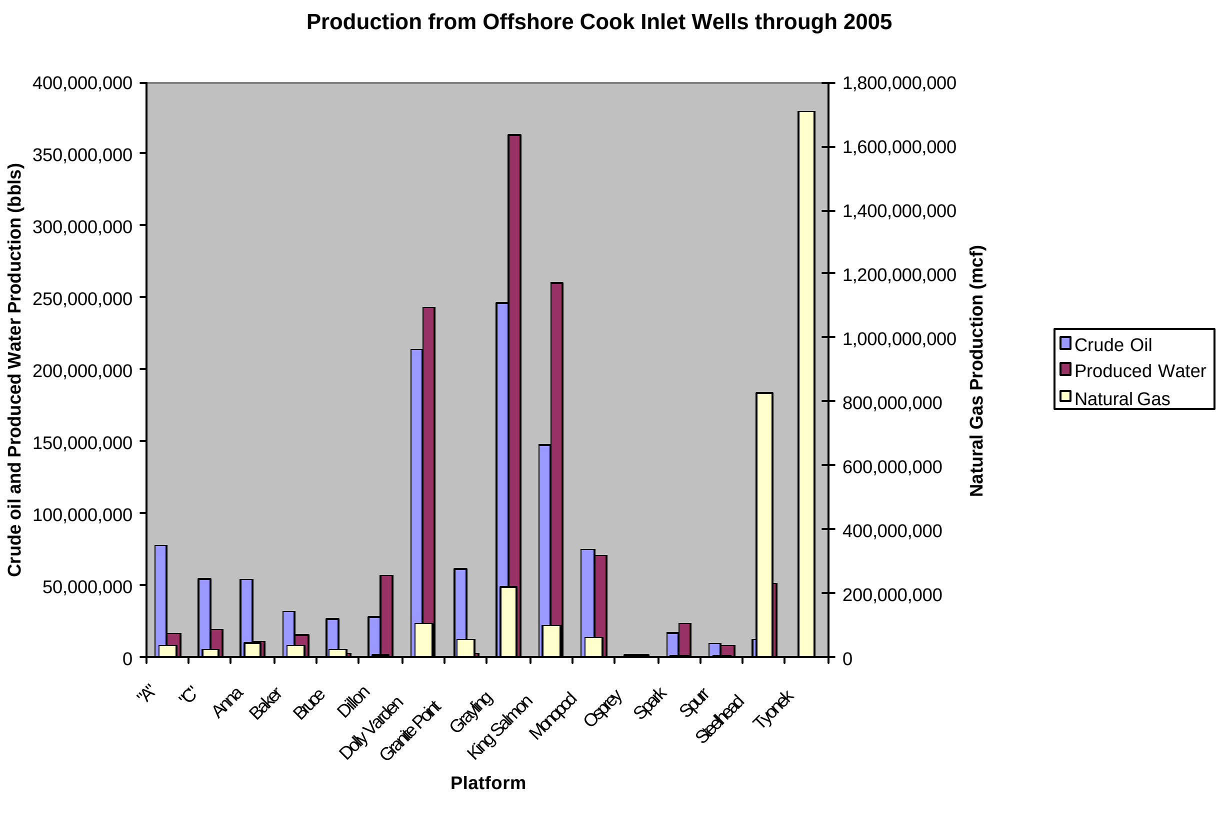
> Drilling fluid discharges could adversely affect prey availability in the immediate vicinity of the discharges because of the burial of benthic organisms or changes in bottom habitat characteristics. Such effects would be of limited size and duration. Exposure to increased pollutant concentrations within designated mixing zones are unlikely to cause adverse effects to beluga whales because of the whales' mobility and limited amount of time within (sic) spent within these areas. Exposure to discharge waters that comply with chronic water quality standards are not expected to adversely affect beluga whales (*Biological Evaluation for the Cook Inlet NPDES Permit*, prepared for U.S. EPA Region 10 Office of Water by Tetra Tech, Inc., January 20, 2006, p. 5-13).

III. Cook Inlet Offshore Drilling Production and Injection Data

Table 2 contains production data for Cook Inlet offshore oil and gas wells by platform, compiled from Alaska Oil and Gas Conservation Commission (AOGCC) databases. The offshore oil wells produce crude oil, natural gas, and produced water, while the gas wells generate only natural gas and produced water.[21] Table 2 also shows the total volume of seawater injected (i.e., "waterflooding") to enhance or maintain oil production.

Figure 2, based on data from Table 2, graphically displays total oil, natural gas, and produced water generation from each Cook Inlet offshore platform through the end of 2005.

Figure 2



[21] AOGCC reporting instructions for Form 10-405, the Monthly Production Report, require producers to identify wells as either Type 1 – oil producer or Type 2 – gas producer.

Table 2

Total Cook Inlet Oil, Natural Gas, and Produced Water Production and Seawater Injection from Start-up through 2005

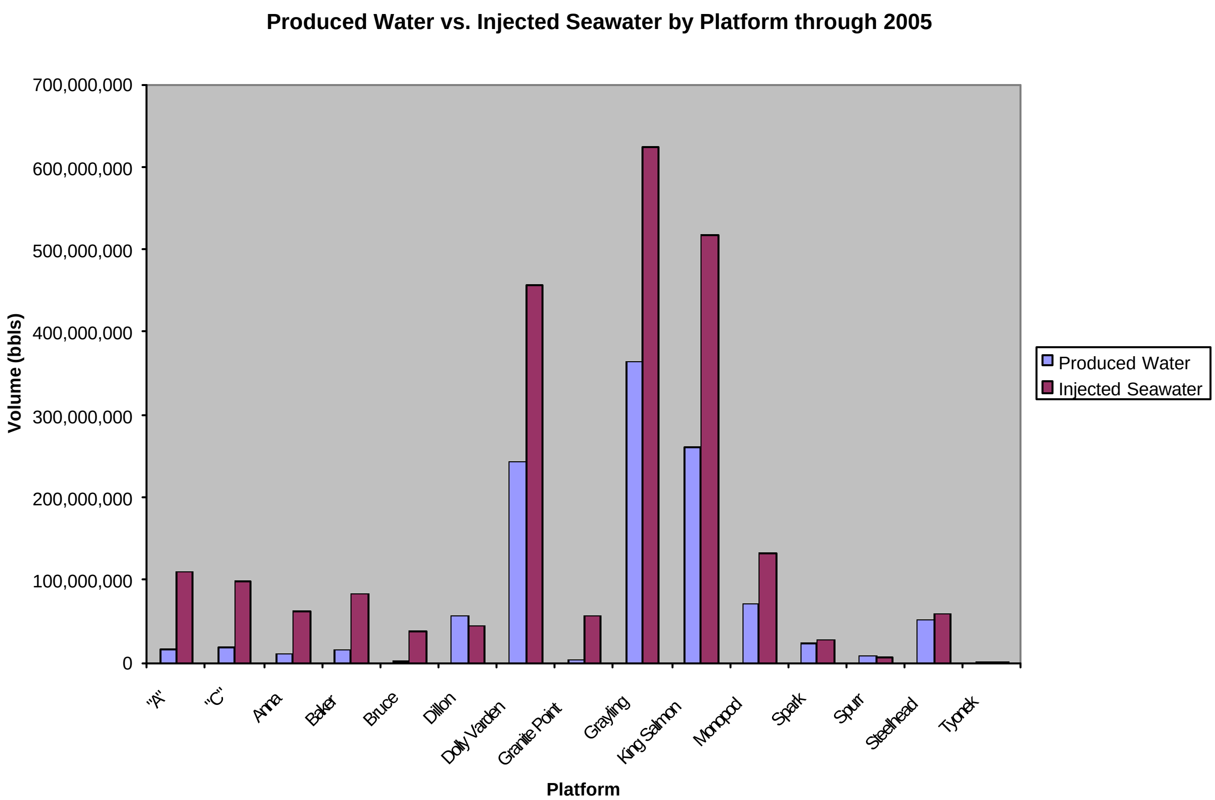
Offshore Platform	Oil Wells - Crude Oil (bbls)	Oil Wells - Nat. Gas (mcf)	Oil Wells - Prod. H20 (bbls)	Gas Wells - Nat. Gas (mcf)	Gas Wells - Prod. H20 (bbls)	TOTALS: Total Cr. Oil (bbls)	Total Nat. Gas (mcf)	Total Prod. H20* (bbls)	Total Sea H2O Injected (bbls)	Yrs. Operat.
"A"	78,084,542	36,407,113	16,576,152	476,535	0	78,084,542	36,883,648	16,576,152	110,056,531	41
Anna	54,220,394	46,819,728	11,236,296			54,220,394	46,819,728	11,236,296	62,636,913	39
Baker	31,931,536	20,618,600	15,747,129	15,907,806	131	31,931,536	36,526,406	15,747,260	83,202,736	40
Bruce	26,766,481	24,831,530	2,750,230	872,758	0	26,766,481	25,704,288	2,750,230	37,978,339	39
"C"	54,723,858	25,139,677	19,572,417			54,723,858	25,139,677	19,572,417	98,854,815	38
Dillon	28,323,625	10,337,409	56,624,197			28,323,625	10,337,409	56,624,197	44,365,995	39
Dolly Varden	213,694,235	72,213,308	243,277,390	34,550,784	0	213,694,235	106,764,092	243,277,390	457,415,259	38
Granite Point	62,027,630	55,873,666	3,065,934			62,027,630	55,873,666	3,065,934	56,697,019	39
Grayling	246,994,106	93,605,049	363,519,807	127,065,445	2,260	246,994,106	220,670,494	363,522,067	624,241,330	38
King Salmon	147,891,083	55,423,117	260,837,506	44,926,210	0	147,891,083	100,349,327	260,837,506	517,782,364	38
Monopod	75,308,434	63,434,084	70,881,514			75,308,434	63,434,084	70,881,514	132,396,589	39
*Osprey***	1,830,072	448,057	2,052,463			1,830,072	448,057	2,052,463	1,747,751	3
Spark	17,508,888	4,603,045	23,694,809	2,165,027	198,430	17,508,888	6,768,072	23,893,239	27,276,029	37
Spurr	9,935,186	2,744,796	8,500,078	3,543,248	0	9,935,186	6,288,044	8,500,078	6,471,739	37
Steelhead	12,668,057	8,123,692	51,103,953	821,920,335	370,414	12,668,057	830,044,027	51,474,367	58,850,021	19
Tyonek				1,707,924,357	665,051		1,707,924,357	665,051	240,781	37
Total	**1,061,908,127**	**520,622,871**	**1,149,439,875**	**2,759,352,505**	**1,236,286**	**1,061,908,127**	**3,279,975,376**	**1,150,676,161**	**2,320,214,211**	
Total (gals)	**44,600,141,334**		**48,276,474,750**			**44,600,141,334**		**48,328,398,762**	**97,448,996,862**	

Notes: There are 42 gallons per barrel (bbl).
"mcf" means thousand cubic feet.

* A tiny fraction of the column Total, approximately 0.05%, has been injected (most of Osprey platform's produced water and a small portion of Anna and Tyonek platforms' produced water).
** Forest Oil's Osprey platform is not included in the Cook Inlet general discharge permit.

Table 2 shows that total injected seawater in Cook Inlet is approximately twice the amount of total produced water generated. Figure 3 compares the volume of produced water generated to the volume of treated seawater injected *by platform* for platforms covered by the general discharge permit. This figure shows that – with the exception of currently shut-in Dillon and Spurr platforms – the volume of injected seawater by platform has been less than the volume of produced water generated and discharged to Cook Inlet. Figure 3 indicates that there was enough capacity in each platform's respective injection zone to accommodate the volume of produced water generated by the platforms' wells had a decision been made during platform start-up to design the platforms for produced water injection.

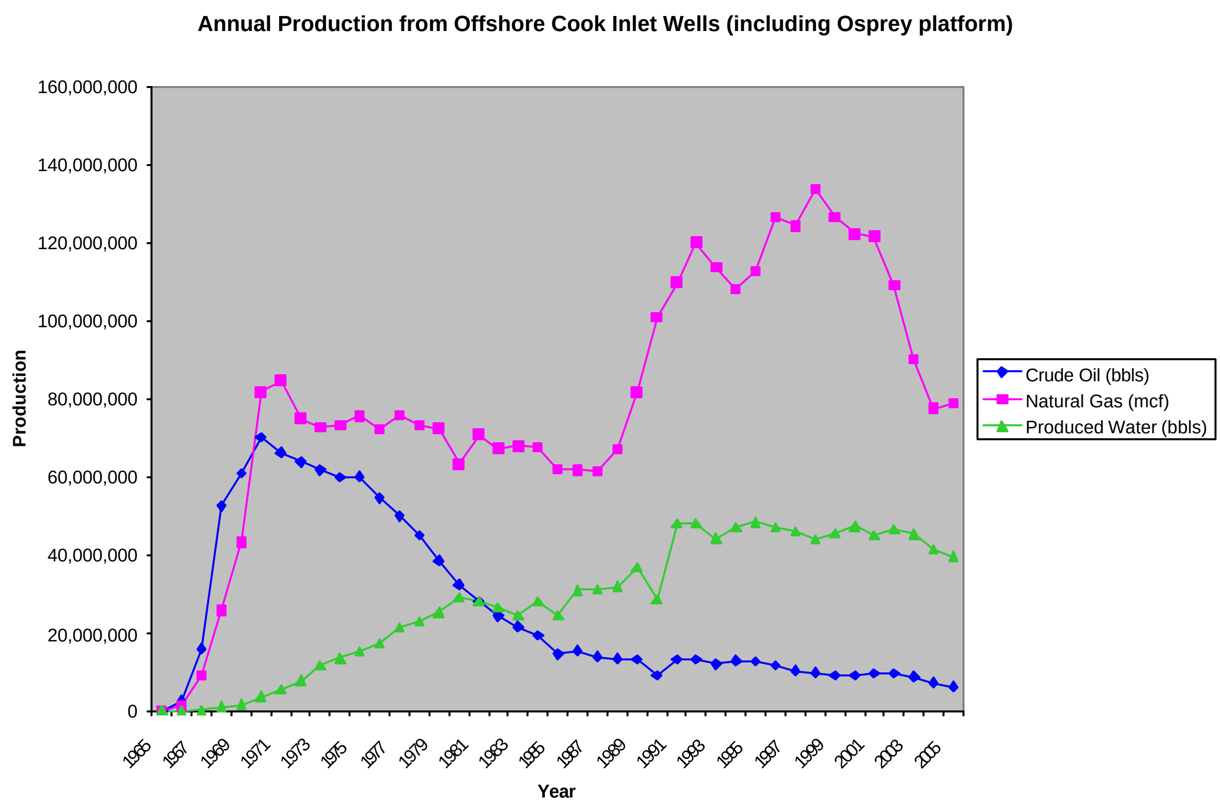
Figure 3



Injection of liquids serves two key purposes: it increases formation pressure which helps oil production, and it provides a well-regulated (by the AOGCC) means of wastewater disposal, e.g., of produced water. Both industry and public needs are well-served by produced water injection into oil-producing formations.

Figure 4 shows total annual production from Cook Inlet's offshore oil and gas wells (AOGCC data). As field development proceeds, oil and gas production initially increases quickly and then declines over a longer period. As shown in Figure 4, produced water generation increases as oil and gas fields age, though this quantity may be affected by the water injection rate into oil and gas reservoirs. *Note that the quantity of Cook Inlet produced water generation has remained roughly unchanged or decreased since 1991. Nevertheless, the draft Clean Water Act permit*

Figure 4



allows an increase in annual produced water discharge from Cook Inlet offshore platforms of 69%.

IV. Cook Inlet Produced Water Discharge Data

Cook Inlet oil and gas producers report offshore discharges from their platforms monthly to EPA and the state under EPA's general discharge permit requirements in "Discharge Monitoring Reports" (DMRs). Nearly all states have "delegated" programs under the federal Clean Water Act where the states issue and enforce discharge permits, however Alaska does not.[22] Thus, EPA currently issues and enforces Alaskan water discharge permits from its Seattle office, but the State of Alaska provides input into EPA's development of the permits. Monthly DMRs contain information on produced water (this section) and drilling wastes (Section V), as well as other forms of wastewater discharges covered by the Clean Water Act (e.g., deck drainage, sanitary wastes, etc.; these other discharges are not covered in this report).

<u>Produced water discharge locations, volume, and composition</u>. Not all produced water generated by Cook Inlet offshore oil and gas platforms is discharged into the marine environment directly. Figure 5 illustrates which platforms send their produced water onshore, where operators separate

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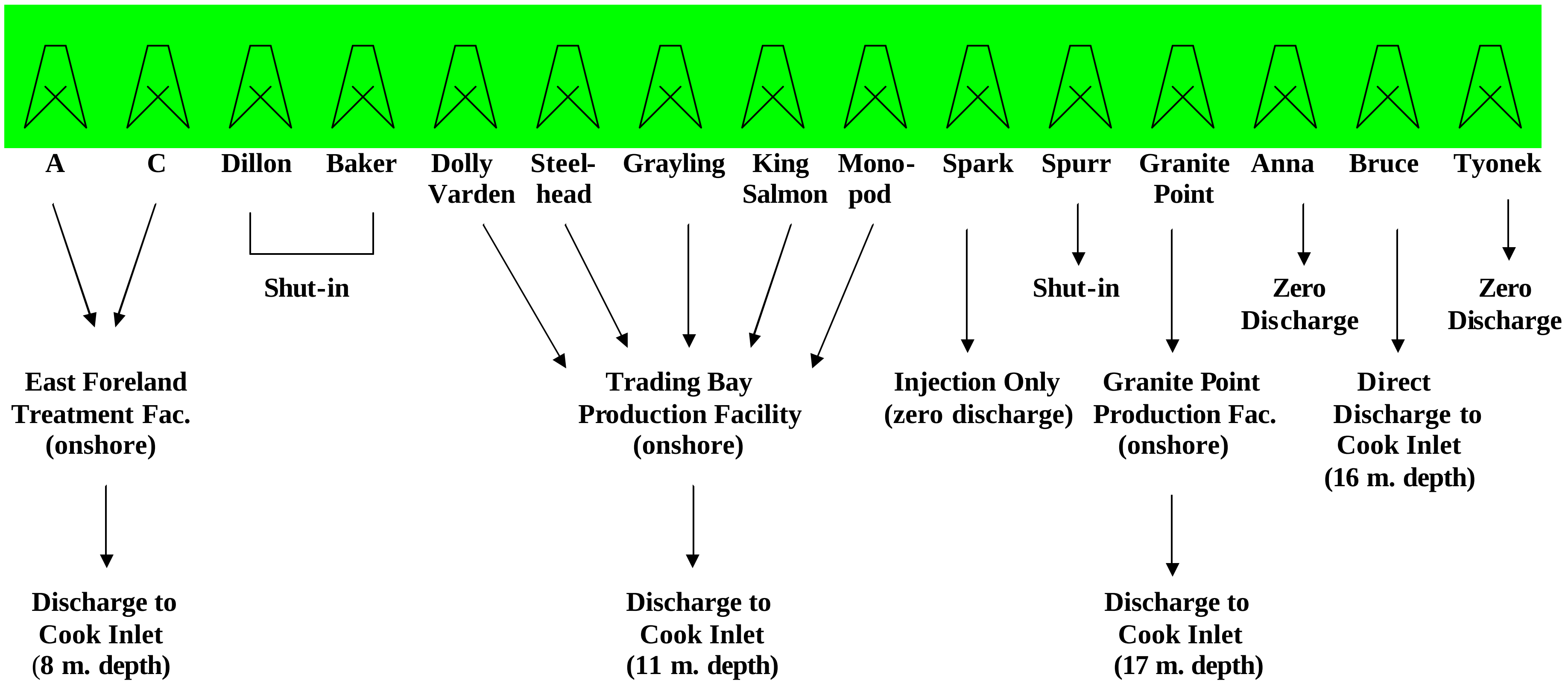
[22] The State of Alaska enacted legislation in 2005 which enables the state to apply for Clean Water Act delegation from EPA.

Figure 5
Platform Discharge Locations for Produced Water as of January 2006



the crude oil, natural gas, and produced water and discharge the still-contaminated produced water into Cook Inlet. Figure 5 also shows that Bruce platform is the only platform currently discharging produced water directly into Cook Inlet.

Table 3 compares current produced water discharge locations shown in Figure 5 with discharge locations allowed in the draft Clean Water Act permit. There are five locations where discharges are allowed in the draft permit which are not discharging at the present time.

Table 3
Cook Inlet Platform and Onshore Facility Produced Water Discharge Locations, Currently and in the Draft Permit

Platform/Onshore Facility	Discharge Location as of January '06	Discharge Allowed in the Draft Permit?
Platform		
"A"	Sent onshore	No – unchanged
Anna	Zero discharge	*Yes – new*
Baker	Shut-in	*Yes – new*
Bruce	Direct discharge	Yes – not new
"C"	Sent onshore	No – unchanged
Dillon	Shut-in	*Yes – new*
Dolly Varden	Sent onshore	No – unchanged
Granite Point	Sent onshore	*Yes – new*
Grayling	Sent onshore	No – unchanged
King Salmon	Sent onshore	No – unchanged
Monopod	Sent onshore	No – unchanged
Spark	Injection only	No – unchanged
Spurr	Shut-in	No – unchanged
Steelhead	Sent onshore	No – unchanged
Tyonek	Zero discharge	*Yes – new*
Onshore Facility		
East Foreland Treatment Facility	Discharge to Cook Inlet	Yes – not new
Granite Point Production Facility	Discharge to Cook Inlet	Yes – not new
Trading Bay Production Facility	Discharge to Cook Inlet	Yes – not new

Table 4 shows average daily produced water generation rates from Cook Inlet's offshore oil and gas operations and the average concentration of the pollutants reported to EPA for 2005 on DMRs (see Appendix 2 for monthly DMR data). Although they are operating under a general discharge permit, each facility has different monitoring and reporting requirements based on the likelihood of the discharge to exceed water quality standards at the edge of the discharge's "mixing zone"[23] whose distance is determined by the state. The Table 4 value for annual produced water generation reported to EPA agrees with that reported to AOGCC within 0.3%.

[23] A "mixing zone" is the area within a receiving water body where the State of Alaska allows discharged contaminants to exceed traditional water quality standards designed to protect people and fish. At the zone's edge,

Table 4 **Produced Water Generation Rate and Annual Average Concentrations of EPA-Permitted Pollutants, 2005**										
Platform/ Facility	**Prod. H2O**	**Oil/Grease**	**Copper**	**Mercury**	**Zinc**	**Silver**	**Lead**	**Arsenic**	**TAH**[24]	**TAqH**[25]
	(mgd)	**(ppm)**	**(ug/l)**	**(ug/l)**	**(ug/l)**	**(ug/l)**	**(ug/l)**	**(ug/l)**	**(ppb)**	**(ppb)**
Anna Platform[26]	0									
Bruce Platform	0.006984	16.3			3617	2.5			15734	
Granite Point Prod. Fac.	0.015691	18.1	17.11	0.2311			4.134		13181	
Trading Bay Prod. Fac.	4.369068	19.6	12.11				2.583		8722	8932
East Foreland Trtmt. Fac.	0.160833	11.5	0.69	0.0000		6.65	0.099	31.85	14140	14475
Total	**4.552576**									
Total (gals/year)	**1,661,690,240**									
Total (bbls/year)	**39,564,053**									
Column Average		**16.4**	**9.97**	**0.1156**	**3617**	**4.58**	**2.272**	**31.85**	**12944**	**11704**

Table 5 shows the percentage of produced water and oil and grease generated by each Cook Inlet discharge location for 2005. This table shows that:

1. The Trading Bay Production Facility, located onshore on the west side of Cook Inlet, represents nearly 96% of the produced water and over 97% of the oil and grease discharged into Cook Inlet from offshore oil and gas operations in 2005;
2. If all three onshore facilities (Trading Bay Production Facility, Granite Point Production Facility, and East Foreland Treatment Facility) injected their discharges to the subsurface, over 99.8% of the produced water discharges into Cook Inlet in 2005 would be eliminated.

Table 5 **Breakdown of Produced Water and Oil and Grease Generation by Cook Inlet Discharger, 2005**				
Platform/Facility	**Prod. H20 gen.**	**Prod. H20**	**Oil/Grease**	**Oil/Grease**
	(gallons/yr)	**(percent)**	**(gallons/yr)**	**(percent)**
Bruce Platform	2,549,160	0.15	42	0.13
Granite Point Prod. Fac.	5,727,215	0.34	104	0.32
Trading Bay Prod. Fac.	1,594,709,820	95.97	31,256	97.44
East Foreland Trtmt. Fac.	58,704,045	3.53	675	2.10
Total	**1,661,690,240**		**32,077**	

the permit writers consider dilution sufficient to meet the standards. Permit writers use hydraulic models to determine the level of dilution necessary.

24 TAH is Total Aromatic Hydrocarbons.

25 TaqH is Total Aqueous Hydrocarbons.

26 As of January 12, 2005, Anna Platform began injecting its produced water (February 18, 2005 letter from Dale A. Haines of Chevron/Unocal to Mr. Chae Park of U.S. EPA Region 10).

Toxic chemicals in produced water discharges. Cook Inlet offshore oil and gas operations' DMRs for produced water for 2005 can be used to assess the quantity of metals released into Cook Inlet from these facilities. Table 4 shows that many pollutants are not measured for every discharge location, however. In order to calculate total discharges into Cook Inlet from these facilities, Cook Inletkeeper calculated a weighted average concentration for each pollutant based on produced water flow rates and data from the facilities which measured particular chemical concentrations. The weighted average concentrations for the discharges' various metals for 2005 are shown in Table 6.

Table 6
Weighted Average Concentration of Metals in Offshore Discharges to Cook Inlet, 2005

Metal	Weighted Average Concentration (micrograms/liter)
Copper	11.72
Mercury	0.02
Zinc	3617
Silver	6.48
Lead	2.73
Arsenic	31.85

Using the data from Table 6 and the total produced water generation rate listed in Table 5 results in the annual quantities of metals released into Cook Inlet from offshore oil and gas operations shown in Table 7.

Table 7
Annual Quantity of Metals in Offshore Drilling Discharges to Cook Inlet, 2005

Metal	Annual Discharge (lbs)
Copper	163
Mercury	0.28
Zinc	50,162
Silver	90
Lead	38
Arsenic	442

V. Cook Inlet Offshore Drilling Waste Discharges

When wells are drilled, drilling fluids (commonly referred to as drilling muds) lubricate and cool the drill bit, carry drill cuttings (rock solids) to the surface, and maintain down-hole pressure to prevent well blowouts. These fluids are specially formulated to achieve appropriate pressure, viscosity (ease of flow), corrosion prevention, and other characteristics. The fluids include minerals such as barite, which may contain cadmium and mercury contaminants. As drilling proceeds and the fluids become mixed with drill cuttings from the hole, the fluids must be diluted and have solids, or cuttings, removed to ensure proper flow characteristics. Excess fluid volume generated is disposed of as drilling waste; the removed cuttings, with some residual drilling fluid, are disposed of as drill cuttings. Drilling fluids can be oil-based, water-based, or synthetic-based.

Drilling waste discharges, representing drilling fluids and drill cuttings, do not occur on a regular basis. These discharges occur periodically over a multi-month period when wells are drilled from offshore platforms or when well workovers occur to increase production. Drilling waste discharges also occur during exploratory operations, i.e., drilling in areas without an existing platform or wells in order to determine whether a formation(s) is commercially viable ("exploratory" operations differ from "production" operations; production operations are the main focus of this report).

Cook Inlet operators are precluded from discharging oil-based drilling fluids into Cook Inlet by the requirements of the existing general discharge permit. Drilling wastes that do not meet the general discharge permit requirements and are not discharged offshore into Cook Inlet or into an offshore Class II disposal well[27] are sent onshore for disposal.

EPA allows discharges of water-based drilling fluids and drill cuttings from coastal operators in Cook Inlet, but not from other coastal operators in the U.S. (see Appendix 1). This is due to EPA's *presuming* (in its mid-1990s ELG analyses) that Cook Inlet contained large areas unfit for grinding and injection of drilling wastes. As discussed in Section VI, the existence of two new grind and inject facilities and several Class II disposal wells in the region belie this assumption.

In Cook Inlet in 2005, operators reported that no drilling wastes (fluids/muds and cuttings) were discharged directly into Cook Inlet from platforms covered by the general discharge permit. It is unclear if the lack of water-based drilling wastes discharged into Cook Inlet in 2005 will continue. Escopeta Oil, a new operator in Cook Inlet, recently stated that it intends to inject its exploratory and production-related drilling wastes[28] even though EPA does not require operators to inject exploratory drilling wastes. In 2001 and 2002, Cook Inlet oil and gas operators reported over 27,410 barrels of drilling wastes discharged directly into Cook Inlet from five platforms: XTO's "A" and "C" platforms, Chevron/Unocal's Steelhead and Monopod platforms, and Forest Oil's Osprey platform (exploratory drilling wastes only).[29]

VI. Current Conditions Warrant a Shift to Zero Discharge

The new general discharge permit for Cook Inlet's offshore oil and gas operations is *the* critical means the federal government uses to protect Cook Inlet waters (the state provides input into federal permit issuance). EPA accepted comments on the draft permit through May 31, 2005.

Among the most favorable economic changes for Cook Inlet offshore oil operations which have occurred since EPA made its 1999 decision to allow discharges is the dramatic increase in the price of oil. The wellhead price of Cook Inlet oil has increased from $12.56 per barrel in 1999 to

[27] Class II disposal wells – part of U.S. EPA's Underground Injection Control program under the Safe Drinking Water Act – are disposal injection wells permitted to accept wastes from oil and gas operations.

[28] Steve Sutherland, Escopeta Oil, Cook Inlet Regional Citizens Advisory Council board meeting on May 19, 2006.

[29] Cook Inletkeeper review of operator-submitted Discharge Monitoring Reports for 2001-2.

$56.33 per barrel in 2006, *an increase of 448% in constant 2006 dollars*.[30] This extraordinary increase should completely change the economic analysis which resulted in the previous EPA decision allowing produced water and drilling waste to be discharged into Cook Inlet.

Using data from the Alaska Department of Revenue Tax Division, the average Cook Inlet wellhead price for a barrel of crude oil in 2005 was $50.21.[31] Given the $30-45 costs of production in Cook Inlet presented to the legislature in April 2006 by Chevron,[32] earnings were approximately $10 per barrel for a total of nearly $59 million profit for Cook Inlet operations in 2005 (almost 5.9 million barrels of oil were produced in Cook Inlet; AOGCC data).

In addition to the enormous increase in the price of oil, Cook Inlet's offshore oil operations benefit from royalty reductions given the companies by the Alaska legislature in 2003[33] when Cook Inlet crude oil was selling for less than $27 per barrel.[34] These royalty reductions, i.e., reductions in the amount of money paid to the state for oil produced on its leased acreage (typically 12.5%), range from 2.5% to 7.5% depending on the oil production rate per platform. Four of the ten Cook Inlet platforms producing oil and covered by the general discharge permit currently receive royalty reductions (Bruce, Monopod, and Steelhead platforms owned by Chevron/Unocal and "C" platform owned by XTO Energy).

Another economic change likely to benefit the industry is the Alaska legislature's probable passage of some version of the Petroleum Production Tax, including a 20% or more tax credit for qualified capital expenditures. Upgrading Cook Inlet platforms' treatment and disposal systems for produced water and drilling wastes certainly would qualify for this tax credit.

Other new economic, technologic, and scientific and TEK evidence and data since the 1999 general discharge permit issuance follow:

<u>Drilling economics: produced water.</u> EPA used a 1994 industry-developed zero discharge study[35] to develop its estimate of the cost to Cook Inlet operators to achieve zero discharge of produced water. The industry's cost analysis included construction of four new pipelines from onshore to offshore platforms for produced water injection and modifications to <u>ten</u> (of the fifteen general

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[30] *Spring 2006 Revenue Sources Book*, Alaska Department of Revenue, Tax Division, Real $2006 Crude Oil & Natural Gas Prices, http://www.tax.state.ak.us/sourcesbook/Real$2006Oil&NatGasPrices.pdf.

[31] *See* http://www.tax.state.ak.us/programs/oil/prices/historicaldata/Cookwellhead.asp (last visited on May 11, 2006).

[32] *See* http://www.akdemocrats.org/ppt/chevron_testimony_4_6_06.pdf, p. 9 (last visited on May 11, 2006).

[33] *See* SB185, http://www.legis.state.ak.us/basis/get_bill.asp?session=23&bill=SB185 (last visited on May 11, 2006).

[34] *See* http://www.tax.state.ak.us/programs/oil/prices/historicaldata/Cookwellhead.asp (last visited on May 11, 2006).

[35] *Zero Discharge Analysis: Trading Bay Production Facility, Cook Inlet, Alaska*, Marathon Oil Company, Unocal Corporation, March 1994.

discharge permit) platforms in preparation for injection. The capital costs of constructing four new offshore pipelines to transport produced water for injection (three new pipelines from Trading Bay Production Facility and one new pipeline from the East Foreland Treatment Facility) are the single most expensive items in industry's/EPA's zero discharge cost estimate. These four pipelines and their associated equipment represent 71% of the predicted $96.9 million capital costs,[36] or $69.0 million for the pipelines (all costs are in 1995$).

Additionally, the estimate included the following currently-unnecessary capital costs for modifications to: 1) two shut-in platforms (Dillon and Baker) - $4.6 million, and 2) three platforms that already inject produced water (Anna, Spark, and Tyonek) - $9.5 million. These currently-unnecessary capital costs represent an additional 15% of the predicted capital costs.

A re-examination of industry's/EPA's zero discharge analysis based on current platform operating conditions would result in substantially less cost to achieve zero discharge because there currently is no need for four new onshore to offshore pipelines, nor for multiple, new platform injection sites. Consider the following, two, lower-cost zero discharge scenarios:

[36] *Development Document*, op. cit., Appendix XI-2, Capital Costs for Option 3, Zero Discharge Via Injection, pp. A-33 – A-42.

Figure 6
Two Zero Discharge Scenarios for Produced Water Based on Current Cook Inlet Drilling Conditions

Scenario 1:

First, if it is in good repair, use the existing pipeline connecting the closed Dillon platform to the East Foreland Treatment Facility as a return line for produced water from onshore, with injection occurring either at Dillon or at "C" platform (connected to Dillon by pipeline), rather than injecting treated seawater at "C" to maintain oil field pressure;

Second, continue using the pipeline(s) from the Granite Point Production Facility to Spark platform as a return line(s) for produced water injection at Spark platform. This line(s) should be able to carry produced water from Bruce and Granite Point platforms for injection at Spark platform; and

Third, there are two, comparatively low-cost zero discharge options for the Trading Bay Production Facility. One or both of these options might need to be utilized to address the large volume of Trading Bay produced water. These options are: 1) construct a single, new large-diameter produced water pipeline from Trading Bay Production Facility to an offshore platform in the McArthur River (King Salmon, Grayling, Steelhead, or Dolly Varden platforms) or Trading Bay (Monopod platform) fields for injection at a platform(s), with optional feeder lines to nearby platforms (assuming the injection formation could assimilate the quantity of produced water generated); 2) when one of the McArthur River field's platforms shuts down or when Monopod shuts down, require that one of the pipelines connecting these platforms to the Trading Bay Production Facility be used (if it is good repair) as a return line for produced water, followed by injection at the shut-in platform.

Scenario 2:

Utilize <u>current</u> geologic (including recent well) data and modern subsurface analysis techniques and drill a Class II disposal well(s) near the Trading Bay Production Facility for produced water disposal. Given the studies pointing to problems with an injection well within three miles of the Trading Bay facility,[37] *however, such a well may need to be as much as five miles away.*

Under Scenario 1, there may need to be zero or perhaps only one new major underwater pipeline constructed. Even with existing discharges from the Bruce platform continuing (EPA estimates this platform will cost $4.6 million to upgrade in 1995$[38]), more than 99% of current produced water discharges would be eliminated under Scenario 1. Thus, by eliminating up to 71% of the estimated capital costs for new pipelines plus the 15% of the estimated capital costs which are unnecessary due to changes in platform status since the industry/EPA zero discharge analysis,

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[37] *Zero Discharge Analysis*, op. cit., p. 2.30 ff.

[38] *Development Document*, op. cit., p. A-39.

86% of the estimated capital costs likely are unnecessary. As a result, EPA's previous overall cost estimate may be as much as seven times as high as today's conditions warrant:

100% / (100% - 86%) = 7.1 times too high an estimate

In its *Development Document* for the ELG, EPA states that potential scaling and well-plugging problems due to produced water injection in the seawater injection wells can be overcome with proper water treatment:

> EPA reviewed the effects of produced water injection and concluded that downhole problems such as calcium carbonate scale precipitation and bacterial growth can be mitigated through the use of proper operating procedures. These procedures consist of pretreatment of the produced water for oil and grease and [total suspended solids], and continued chemical treatment of the injection stream. The proper usage of scale inhibitors can minimize scale deposits in the injection equipment, tubing flow lines, and injectors. The usage of biocides can minimize bacterial growth, thus reducing the formation of hydrogen sulfide. In addition to chemical treatment, annual well workovers can minimize scale build-up.[39]

As for Scenario 2, drilling one or more onshore disposal injection wells near the Trading Bay Production Facility would eliminate 96% of the produced water now discharged into Cook Inlet. While the 1994 industry-developed *Zero Discharge Analysis* study concluded that a disposal injection well in the vicinity of the Trading Bay Production Facility was not technically feasible[40] or cost effective, the study provided very limited documentation and raised a number of questions which need to be resolved by independent, EPA technical experts familiar with the region's subsurface geology. Additionally, since the time of the study, Forest Oil has successfully drilled and operated a Class II disposal well nearby, drilled into the Kenai formation approximately three miles from the Trading Bay Production Facility.[41]

Savings from the zero discharge scenarios proposed above include the lack of need for the existing onshore oil/water separation operations now used to meet permit discharge requirements since produced water (which is contaminated with hydrocarbons) could be injected; and no need for a diffuser for the Trading Bay Production Facility discharge.[42] Costs likely would include analysis of injection strata; pumping costs; modification of wastewater treatment operations prior

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[39] Ibid., p. XI-39.

[40] *Zero Discharge Analysis*, op. cit. p. 2.30 ff. The two technical concerns raised in the study were the potential for an over-pressurized formation which could result in undesirable vertical fractures (potentially contaminating a drinking water aquifer), and injection of produced water negatively impacting permeability of the formation's clays. The authors acknowledge the uncertain nature of both concerns, however. In fact, numerous water injection wells exist 5-9 miles from Trading Bay Production Facility (data from Stephen Davies, AOGCC).

[41] West McArthur River Unit 4 Class II disposal injection well.

[42] *See* draft U.S. EPA Pemit No.: AKG-31-5000, section G.2.

to injection; permitting of injection wells; and pipeline and injection well construction and/or reconditioning costs (as needed).

UK Offshore Operators Association and member companies issued a zero discharge study in 2005[43] where the authors found the average cost of converting seawater injection wells to produced water injection wells, not including new pipeline costs, was 5,000 British Pounds per ton of oil removed, or approximately $30 per gallon of oil not entering the marine environment.[44] This industry-derived figure is far less than calculated by EPA in its *Development Document* for the ELG; EPA's estimate for platform modifications and well injection costs alone (i.e., not including engineering, insurance and other costs, as well as not including expensive new pipelines) based on designs submitted by industry was $36.4 million (1995$)[45] for capital and operations & maintenance costs. Assuming 10 years of operation with 32,077 gallons of oil generated annually (see Table 5), the cost of platform-based injection would be at least $113 per gallon of oil (1995$) not entering the marine environment. Since 2005$ are worth over one-fourth more than 1995$, EPA's *Development Document* figure is likely to be low. EPA's cost/gallon figure is nearly four times higher than estimated by industry in the UK for injection of produced water into platform-based wells rather than seawater injection.

Table 8 lists all active Class II oil and gas waste injection wells in the Cook Inlet watershed, i.e., permitted wells designed to accept oil and gas-related wastewaters such as the produced water generated by the Cook Inlet offshore platform wells. *This table shows that all offshore platform operators have at least one offshore Class II injection well in operation during 2005 which can be used for produced water disposal.* Currently, ConocoPhillips injects produced water from its Tyonek platform, Chevron/Unocal injects water from its Anna platform and, since late 2002, Forest Oil injects its produced water at the Osprey platform following onshore oil-water separation. Clearly, the industry already has started moving towards injection of produced water, with each of these examples supporting the assertion that produced water injection is economically viable for Cook Inlet's offshore platforms.

Because of:

- *the high price of oil and state royalty reductions,*
- *the lack of adequate technical evaluation by EPA to date of lower-cost, zero discharge scenarios,*
- *the number and ownership of usable Class II wells offshore, and*
- *the fact that three of twelve (25%) operating Cook Inlet platforms already inject their produced water,*

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[43] *Management of Produced Water on Offshore Oil Installations: A Comparative Assessment Using Flow Analysis – Final Report*, Policy Studies Institute for the UK Offshore Operators Association and its member companies, March 2005. *See* http://www.psi.org.uk/docs/2005/UKOOA/ProducedWater-Workingpaper.pdf (last visited on May 9, 2006).

[44] Ibid., p. 50.

[45] *Development Document*, op. cit., Table XI-18 (including only Platform Modification, Injection Equipment, Injection Well, and O & M costs), p. XI-41.

EPA needs to update its economic analysis of zero discharge for Cook Inlet produced water to incorporate these factors.

Table 8 **Active Class II Disposal Wells in the Cook Inlet Watershed**[46]			
Facility	**Owner/ Operator**	**Location**	**Yr. Opened**
Class II Injection Wells (for produced water)			
Beaver Creek Unit 2	Marathon	Beaver Creek Gas Field	1967
Beluga River Unit BRWD-1	ConocoPhillips	Beluga Gas Field	1986
Deep Creek NNA 1	Chevron/Unocal	Ninilchik area	2002
Granite Point ST 44-11	Chevron/Unocal	Granite Point Field (offshore)	1968
Ivan River Unit 14-31	Chevron/Unocal	Beluga area	1975
Kenai Unit 11-17	Marathon	Kenai Gas Field	1982
Kenai Unit 24-7RD	Marathon	Kenai Gas Field	2005
Kenai Unit WD-1	Marathon	Kenai Gas Field	1982
Middle Ground Shoal C44-14RD	XTO Energy	Middle Ground Shoal Field (offshore)	1978
North Cook Inlet Unit A-12	ConocoPhillips	North Cook Inlet Gas Field (offshore)	1970
North Trading Bay S-05	Marathon	Trading Bay Field (offshore)	1969
Redoubt Unit D1	Forest Oil	Redoubt Shoal Field (offshore)	2001
Sterling Unit 43-09	Marathon	Soldotna area	1963
Swanson River Unit 31-33WD	Chevron/Unocal	Kenai National Wildlife Refuge	1981
Swanson River Unit 32-33 WD	Chevron/Unocal	Kenai National Wildlife Refuge	1981
West McArthur River Unit 4	Forest Oil	W. McArthur River Field	1998

<u>Drilling economics: drilling wastes.</u> In its 1996 final rule covering coastal oil and gas extraction point source discharges,[47] EPA assumed that Cook Inlet drilling wastes would be disposed of in a landfill because it could not evaluate the availability of local grind and inject facilities. At the time, EPA knew of only a single landfill for drilling wastes within Cook Inlet (the Kustatan landfill), and it was unclear if all producers of drilling wastes would be able to use this landfill. Thus, EPA utilized land disposal costs that were far too high for current conditions in its economic analysis, i.e., EPA assumed that the drilling wastes would be sent to a landfill in Oregon.[48]

Table 9 lists all active drilling waste management facilities in the Cook Inlet watershed. This table shows that – for drilling wastes – Chevron/Unocal and Marathon opened facilities to grind and inject drilling wastes since the 1999 Cook Inlet general discharge permit was issued. Additionally, XTO Energy sends its drilling wastes to a nearby Class II injection well the company operates[49] (see Table 8). Moreover, since beginning oil production on the Osprey

[46] Class II well data from the Alaska Oil and Gas Conservation Commission.

[47] *See* 61 <u>Federal Register</u> 66090 (December 16, 1996).

[48] Ibid.

[49] Personal communication with Brad Hill, XTO Energy, May 9, 2006.

Table 9
Active Drilling Waste Management Facilities in the Cook Inlet Watershed[50]

Facility	Owner/ Operator	Location	Yr. Opened
Landfills (for drilling wastes)			
Beaver Creek Drilling Waste LF	Marathon	Beaver Creek Gas Field	Early 1980s
Beluga Central Drilling Waste LF	ConocoPhillips	Beluga Gas Field	1987
Envirotech Drilling Waste Treatment Facility and Inert Waste LF	Envirotech	Tyonek area	2003
Envirotech Nikiski Drilling Waste Treatment Facility	Envirotech	Nikiski	2004
Kustatan Ridge Drilling Waste LF	Chevron/Unocal	Trading Bay	1990
Swanson River Central Drilling Waste LF	Chevron/Unocal	Swanson River Oil and Gas Field	1986
West McArthur River Drilling Waste LF	Forest Oil	Trading Bay	1996
Grind & Inject Facilities (for drilling wastes)			
Bruce Platform G & I Facility	Chevron/Unocal	Bruce Platform	2002
41-18 G & I Treatment Facility	Marathon	Kenai Gas Field	1999

platform and for its fifth and last exploratory well, Forest Oil has grinded and injected its drilling wastes.[51] The industry already has moved towards injection of drilling wastes, with each of these examples showing that grinding and injecting drilling wastes is economically viable for Cook Inlet's offshore platforms.

Because of:

- *the high price of oil and state royalty reductions, and*
- *the construction of several new drilling waste management facilities in the area,*

EPA needs to update its economic analysis of zero discharge for Cook Inlet drilling wastes to incorporate these factors.

Disposal technology: drilling wastes. EPA needs to re-evaluate its previous assessment that shows injection of drilling wastes to be technically infeasible in the Cook Inlet region given Forest Oil's current practice with Osprey, Chevron/Unocal and Marathon's recently-opened grind and inject facilities, and XTO Energy's use of its Class II disposal well for drilling wastes.

[50] Drilling waste management facility data from Bob Blankenburg, Alaska Department of Environmental Conservation.

[51] Correspondence from Matt Rader, Alaska Department of Natural Resources to Lois Epstein, July 10, 2003.

Recent technological developments to prevent injection well plugging mean it is more feasible than ever for Cook Inlet operators to inject drilling wastes.[52] In its 1996 *Development Document*, EPA stated that the Agency was "unable to estimate the degree to which injection would be available in Cook Inlet."[53] Given the technology and facility changes since, EPA clearly should re-examine this portion of its analysis in consultation with the AOGCC prior to issuance of a new general discharge permit.

Further, in 2003 Marathon stated it had reduced its exploration and production disposal costs for its Cook Inlet operations by using water-based drilling fluids and beneficial reuse of materials following water-washing, thus reducing the amount of its drilling wastes requiring Class II disposal wells. These changes reduced Marathon's disposal costs from $53.63 per barrel in 1995 to $5.85 per barrel in the 2000-2003 time period.[54]

Because:

- *Cook Inlet operators now are injecting substantial amounts of Cook Inlet drilling wastes,*
- *improved drilling waste injection technologies are available throughout the Cook Inlet region, and*
- *Marathon has developed innovative ways to reduce the amount of drilling wastes requiring injection,*

EPA – in conjunction with AOGCC – needs to update its technological analysis of zero discharge for Cook Inlet drilling wastes to incorporate these factors.

Oil impacts on salmon. National Marine Fisheries Service (NMFS) scientists who have done research following the 1989 *Exxon Valdez* crude oil spill found that crude oil constituents are significantly more toxic to pink salmon and herring than previously recognized. Instead of toxicities in the parts per million (ppm) range, NMFS researchers observed toxicities in the parts per billion (ppb) range for salmon and herring eggs. Hatchlings were deformed at levels of contaminants 1,000 times less than previously measured.[55]

Because salmon and herring eggs are adversely impacted by oil contamination at levels 1,000 times less than previously recognized, EPA needs to update its scientific analysis of the impacts of offshore discharges on Cook Inlet marine organisms.

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[52] "*Problem solver: Invention can handle rock disposal on Slope*," Sarana Schell, Anchorage Daily News, September 8, 2003.

[53] *Development Document*, op. cit., p. VII-52.

[54] *Onshore Drilling Waste Management: Beneficial Reuse of Cuttings*, Mark L. Susich (Marathon Oil Company) and Max W. Schwenne (OASIS Environmental, Inc.), undated.

[55] *See* http://www.afsc.noaa.gov/abl/oilspill/fish.htm (last visited on April 17, 2006).

Contamination in Cook Inlet subsistence foods. A 2003 EPA study[56] shows that Cook Inlet seafoods contain varying levels of polycyclic aromatic hydrocarbons (chemicals from petroleum production) and metals (including mercury, cadmium, and lead, which are contained in oil industry discharges) for seafood samples collected in 1997. The contaminants found were not – and are not – at levels affecting fish populations, however, the contaminants can contribute to the adverse changes in seafood described by Tribal members and documented by EPA, described in Section II.

Importantly, the EPA study focused solely on the effects of individual pollutants, not the impacts of two or more pollutants simultaneously contained in fish tissues consumed by humans. A study of multiple pollutants acting in concert to produce biological impacts could help shed light on the adverse changes in seafood described by Tribal members.

The presence of toxic contaminants in subsistence foods documented in EPA's study, however, argues against allowing additional toxic discharges into Cook Inlet because of potential, adverse cumulative impacts over time.

Recent collection of scientific and TEK data on Cook Inlet seafoods show levels of contamination that may be impairing seafood quality, so EPA should update its scientific analysis of the impacts of offshore discharges on Cook Inlet marine organisms.

Cook Inlet beluga whales. Cook Inlet's beluga whale population was classified as "depleted" under the Marine Mammal Protection Act in 2000 by NMFS. Declining beluga whale populations are shown in Figure 7, based on data from NMFS.[57]

[56] *Survey of Chemical Contaminants in Seafoods Collected in the Vicinity of Tyonek, Seldovia, Port Graham and Nanwalek in Cook Inlet, Alaska*, U.S. Environmental Protection Agency, Region 10, EPA 910-R-01-003, December 2003.

[57] U.S. Marine Mammal Commission – Annual Report for 2004, Bethesda, MD, May 2005, p. 40 (http://www.mmc.gov/reports/annual/pdf/2004annualreport.pdf, last visited on May 25, 2006).

Figure 7
Abundance Estimates for Cook Inlet Beluga Whales, 1994-2004

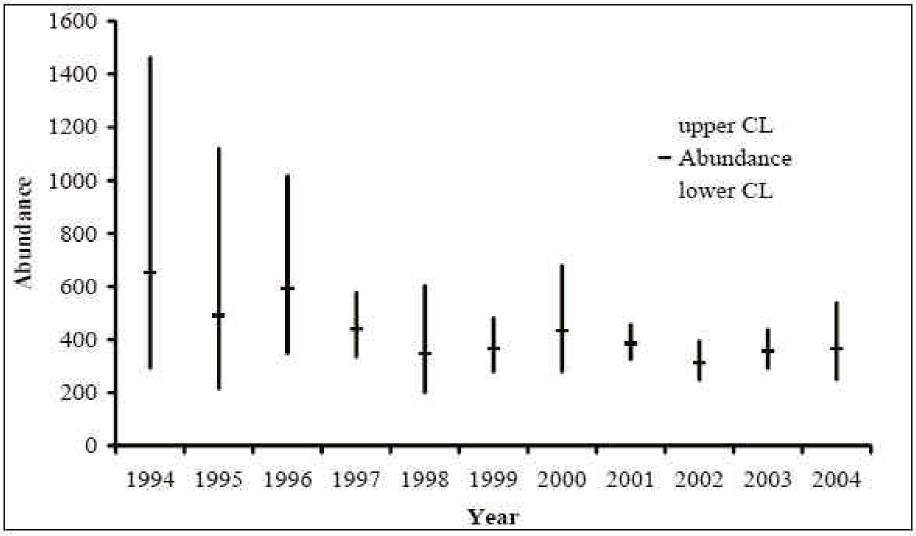

Figure 13. Abundance (and upper and lower confidence limits) of Cook Inlet beluga whales, 1994–2004. Data provided by the National Marine Fisheries Service.

As noted in Section II, EPA acknowledged in the past that Cook Inlet's offshore oil and gas operations' discharges may be contributing to the beluga whale's decline. There have not been any studies to date looking at whether Cook Inlet belugas are metabolizing oil. One chemical discharged by Cook Inlet operations in particular however, copper, has been found in high concentrations in Cook Inlet beluga whales[58] – the toxicologic implications of high copper levels currently are unknown.

Based on NMFS' data on the lack of growth in the number of the relatively few Cook Inlet beluga whales (see Figure 7), NMFS recently began a process to determine whether the Cook Inlet beluga whale should be classified as a "threatened" or "endangered" species under the federal Endangered Species Act.[59]

EPA – in conjunction with NMFS – needs to determine based on recent scientific data whether zero discharge is necessary to protect Cook Inlet's "depleted" and potentially "threatened" or "endangered" beluga whale population.

[58] *Concentrations of polychlorinated biphenyls (PCB's), chlorinated pesticides, and heavy metals and other elements in tissues of beluga,* ***Delphinapterus leucas****, from Cook Inlet, Alaska*, Stephen A. Wise, Marine Fisheries Review, June 22, 2000.

[59] *See* 71 Federal Register 14836 (March 24, 2006). This Federal Register notice from NMFS is a request for information relevant to reassessing the status of the Cook Inlet beluga whale.

VIII. Conclusion

EPA likely will issue a new discharge permit for Cook Inlet offshore oil and gas operations in 2006. This new permit's discharge specifications, including pollutant limits, monitoring frequency and techniques, and reporting requirements, are the primary means the federal government uses to keep Cook Inlet marine waters healthy.

The aging, and consequently less productive nature, of nearly all Cook Inlet offshore oil and gas fields – illustrated in Figure 4 – means that additional platform closures are possible regardless of EPA's actions on this permit. Bearing this in mind, Cook Inletkeeper makes the following key recommendation to EPA for consideration in general discharge permit renewal:

EPA needs to update the economic, technologic, and scientific information used in the 1999 general discharge permit process. EPA should re-evaluate its decision that zero discharge is not warranted in the renewed permit given known and projected, adverse, economic and environmental impacts on the Cook Inlet region should the discharges continue.

Appendices

Appendix 1
EPA's Regulations for Coastal Oil and Gas Operations

:xcerpted from 40 CFR 435.43:

Stream	Pollutant parameter	BAT effluent limitations
roduced Water:		
(A) All coastal areas except Cook Inlet.	....	No discharge.
(B) Cook Inlet.....................	Oil & Grease.....................	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
rilling Fluids, Drill Cuttings, and Dewatering Effluent: \1\		
(A) All coastal areas except Cook Inlet.	....	No discharge.
(B) Cook Inlet:.....................		
Water-based drilling fluids, drill cuttings, and dewatering effluent.	SPP Toxicity.......................	Minimum 96-hour LC5. of the SPP Toxicity Test \4\ shall be 3% by volume.
	Free oil...........................	No discharge. \2\
	Diesel oil.........................	No discharge.
	Mercury............................	1 mg/kg dry weight maximum in the stock barite.
	Cadmium............................	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids and dewatering effluent.	....	No discharge.
Drill cuttings associated with non-aqueous drilling fluids.	....	No discharge. \5\
ell Treatment, Workover and Completion Fluids:		
(A) All coastal areas except Cook Inlet.	....	No discharge.
(B) Cook Inlet.....................	Oil & Grease.....................	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
roduced Sand...........................	....	No discharge.
eck Drainage...........................	Free Oil \3\........................	No discharge.
omestic Waste..........................	Foam................................	No discharge.

1\ BAT limitations for dewatering effluent are applicable prospectively, BAT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.
2\ As determined by the static sheen test (see appendix 1 to 40 CFR Part 435, subpart A).
3\ As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
4\ As determined by the suspended particulate phase (SPP) toxicity test (see Appendix 2 of Subpart A of this part).
5\ When Cook Inlet operators cannot comply with this no discharge requirement due to technical limitations (see Appendix 1 of Subpart D of this part), Cook Inlet operators shall meet the same stock limitations (C16-C18 internal olefin) and discharge limitations for drill cuttings associated with non-aqueous drilling fluids for operators in Offshore waters (see § 435.13) in order to discharge drill cuttings associated with non-aqueous drilling fluids.

Appendix 2
Discharge Monitoring Reports for Produced Water from Cook Inlet's Offshore Platforms for 2005

Operator/Facility	Pr. H2O (mgd)	O/G (av)	O/G (max)	Cu (av)	Cu (max)	Hg (av)	Hg (max)	Zn (av)	Zn (max)	Ag (av)	Ag (max)	Pb (av)	Pb (max)	As (av)	As (max)	TAH (av)	TAH (max)	TAqH (av)	TAqH (max)
Chevron/Unocal																			
Anna Platform																			
12/5	0.000000																		
11/5	0.000000																		
10/5	0.000000																		
9/5	0.000000																		
8/5	0.000000																		
7/5	0.000000																		
6/5	0.000000																		
5/5	0.000000																		
4/5	0.000000																		
3/5	0.000000																		
2/5	0.000000																		
1/5	0.000000																		
Average																			
Bruce Platform																			
12/5	0.007277	14.0	16.0					154	154	2.0000	2.0000					15640	15640		
11/5	0.000000																		
10/5	0.005229	20.0	20.0					631	631	3.0000	3.0000					15640	15640		
9/5	0.009904	22.0	29.0					683	683	8.0000	8.0000					14890	14890		
8/5	0.007509	13.0	15.0					274	274	2.0000	2.0000					16440	16440		
7/5	0.007680	19.0	20.0					609	609	2.0000	2.0000					13720	13720		
6/5	0.007212	17.0	21.0					994	994	1.0000	1.0000					14390	14390		
5/5	0.007494	16.0	28.0					1270	1270	2.0000	2.0000					14790	14790		
4/5	0.008013	15.0	18.0					1230	1230	1.0000	1.0000					17480	17480		
3/5	0.007160	13.0	21.0					1870	1870	2.0000	2.0000					15660	15660		
2/5	0.007306	19.0	23.0					23900	23900	2.0000	2.0000					15455	15455		
1/5	0.009027	11.0	14.0					4710	4710	2.0000	2.0000					18870	18870		
Average	**0.006984**	**16.3**	**20.5**					**3617**	**3617**	**2.5000**	**2.5000**					**15734**	**15734**		
Granite Pt. Prod. Fac.																			
12/5	0.018627	19.0	26.0	7.00	7.00	0.2000	0.2000					2.000	2.000			13900	13900		
11/5	0.019458	16.0	17.0	7.00	7.00	0.2000	0.2000					7.600	7.600			10740	10740		
10/5	0.017983	14.0	19.0	84.00	84.00	0.2000	0.2000					11.000	11.000			12590	12590		
9/5	0.019360	15.0	23.0	10.00	10.00	0.2000	0.2000					1.000	1.000			15200	15200		
8/5	0.016867	20.0	28.0	11.00	11.00	0.2000	0.2000					3.700	3.700			13000	13000		
7/5	0.016715	20.0	28.0	15.00	15.00	0.2000	0.2000					3.300	3.300			11630	11630		

Appendix 2, continued

Operator/Facility	Pr. H2O (mgd)	O/G (av)	O/G (max)	Cu (av)	Cu (max)	Hg (av)	Hg (max)	Zn (av)	Zn (max)	Ag (av)	Ag (max)	Pb (av)	Pb (max)	As (av)	As (max)	TAH (av)	TAH (max)	TAqH (av)	TAqH (max)
Granite Pt. Prod. Fac.																			
6/5	0.012440	21.0	28.0	10.00	10.00	0.2000	0.2000					1.610	1.610			14190	14190		
5/5	0.015539	18.0	22.0	5.00	5.00	0.2000	0.2000					5.000	5.000			13840	14390		
4/5	0.028644	18.0	18.0	-	-	-	-					-	-			-	-		
3/5	0.000000																		
2/5	0.000000																		
1/5	0.022662	20.0	22.0	5.00	5.00	0.4800	0.4800					2.000	2.000			13540	13540		
Average	**0.015691**	**18.1**	**23.1**	**17.11**	**17.11**	**0.2311**	**0.2311**					**4.134**	**4.134**			**13181**	**13242**		
Trading Bay Production. Fac.																			
12/5	4.254137	24.0	33.0	6.80	8.00							2.000	3.000			8280	9820	8374	9919
11/5	4.473566	21.0	28.0	37.30	93.00							4.000	9.000			12320	22920	12429	23023
10/5	4.402039	19.0	22.0	23.80	86.00							5.000	8.000			8388	9100	8505	9250
9/5	4.410095	20.0	24.0	27.70	50.00							1.000	2.000			7763	8620	7887	8760
8/5	4.437456	19.0	27.0	7.70	10.00							5.000	10.000			9083	9890	9177	9972
7/5	4.611490	16.0	22.0	6.70	8.00							2.000	3.000			7254	8160	7348	8280
6/5	4.481904	18.0	24.0	5.60	6.00							2.000	3.000			9520	14700	9644	14819
5/5	4.459338	17.0	24.0	5.00	5.00							2.000	2.000			10208	21020	10356	21174
4/5	4.380642	29.0	60.0	5.40	12.00							2.000	3.000			7788	8380	7928	8516
3/5	4.129437	18.0	24.0	4.80	7.00							2.000	2.000			7618	8080	7754	8237
2/5	4.236486	16.0	27.0	9.70	25.00							2.000	2.000			7382	8090	7818	8707
1/5	4.152223	18.0	26.0	4.80	8.00							2.000	3.000			9059	9760	9968	10816
Average	**4.369068**	**19.6**	**28.4**	**12.11**	**26.50**							**2.583**	**4.167**			**8722**	**11545**	**8932**	**11789**
XTO Energy																			
E. Foreland Trtmt. Fac.																			
12/5	0.218000	11.0	15.0	0.00	0.00	0.0000	0.0000			61.2000	61.2000	0.000	0.000	186.0000	186.0000	15340	15340	15340	15340
11/5	0.212000	8.0	9.0	0.00	0.00	0.0000	0.0000			0.0381	0.0381	0.000	0.000	0.0985	0.0985	15990	15990	16191	16191
10/5	0.177000	8.0	13.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.000	0.000	0.0000	0.0000	14260	14260	14438	14438
9/5	0.159000	11.0	12.0	7.54	7.54	0.0000	0.0000			11.8000	11.8000	1.080	1.080	163.0000	163.0000	14000	14000	14229	14229
8/5	0.137000	12.0	16.0	-	-	-	-			-	-	-	-	-	-	-	-	-	-
7/5	0.141000	12.0	16.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.007	0.007	0.0400	0.0400	11530	11530	11702	11702
6/5	0.138000	14.0	20.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.000	0.000	0.0400	0.0400	11010	11010	11242	11242
5/5	0.138000	11.0	14.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.000	0.000	0.0400	0.0400	9821	9821	10151	10151
4/5	0.140000	15.0	23.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.003	0.003	0.0400	0.0400	17900	17900	18136	18136
3/5	0.148000	13.0	20.0	0.00	0.00	0.0000	0.0000			0.0016	0.0016	0.000	0.000	0.0362	0.0362	15790	15790	16026	16026
2/5	0.165000	6.0	7.0	0.01	0.01	0.0002	0.0002			0.1000	0.1000	0.001	0.001	0.0025	0.0025	14120	14120	14518	14518
1/5	0.157000	17.0	23.0	0.00	0.00	0.0000	0.0000			0.0000	0.0000	0.000	0.000	1.0000	1.0000	15780	15780	17254	17254
Average	**0.160833**	**11.5**	**15.7**	**0.69**	**0.69**	**0.0000**	**0.0000**			**6.6491**	**6.6491**	**0.099**	**0.099**	**31.8452**	**31.8452**	**14140**	**14140**	**14475**	**14475**

Appendix 2, continued

Operator/Facility	Pr. H2O (mgd)	O/G (av)	O/G (max)	Cu (av)	Cu (max)	Hg (av)	Hg (max)	Zn (av)	Zn (max)	Ag (av)	Ag (max)	Pb (av)	Pb (max)	As (av)	As (max)	TAH (av)	TAH (max)	TAqH (av)	TAqH (max)
Phillips Petroleum																			
Tyonek A Platform																			
12/5	0.000000																		
11/5	0.000000																		
10/5	0.000000																		
9/5	0.000000																		
8/5	0.000000																		
7/5	0.000000																		
6/5	0.000000																		
5/5	0.000000																		
4/5	0.000000																		
3/5	0.000000																		
2/5	0.000000																		
1/5	0.000000																		
Average	**0.000000**																		