Kachemak Bay Conservation Society

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**SUBMITTED VIA EMAIL**
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September 14, 2011

Daniel T. Seamont, Jr., Chair
Alaska Oil & Gas Conservation Commission
333 W. 7th Avenue, Suite 100
Anchorage, AK 99501

**RE: Docket OTH-10-16**

Dear Mr. Seamont:

Thank you for the opportunity to comment on the above-referenced docket regarding whether changes or additions may be needed to the AOGCC's regulations governing drilling, rig workover and well control in offshore and ultra-extended reach wells drilled in areas of the State of Alaska under the AOGCC's jurisdiction. The extreme difficulties of responding to the 2010 *BP Deepwater Horizon* oil and gas blowout in the Gulf of Mexico during the summer of 2010 highlight the challenges of responding to such incidents in the more harsh, less temperate climate and conditions found in Alaskan waters. Given the experience gained from the BP Gulf oil spill disaster, and recognizing the history of blow-outs and near-misses in Alaska, we applaud AOGCC for opening this docket, and through these comments, we strongly encourage AOGCC to adopt new rules require Best Available Technology (BAT) to prevent and respond to blow-outs.

As we learned during the *Exxon Valdez*, and as we were starkly reminded with the *BP Gulf Disaster*, complacency is the enemy of responsible management and balanced development. Yet oil and gas companies, together with various state and federal agencies in Alaska, continue to push back against stronger blowout prevention and response standards. They argue because such events are rare or "unlikely," we need not invest in the safeguards needed to protect our spectacular fisheries and the communities who depend on them.[1] But as the Exxon & BP catastrophes clearly illustrate, the consequences and severity of an incident cannot be confused with its probability. As a result, we urge AOGCC to adopt rules that will address all foreseeable contingencies that attach to oil and gas drilling in Alaska's remote waters.

The marine waters of Cook Inlet are dominated by extreme tides and temperatures, where high winds, fog, darkness and winter ice make oil spill clean-up virtually impossible for significant portions of the year. As a result, it is more important than ever for AOGCC to address the prevention side of the

[1] http://www.care2.com/causes/doi-concluded-massive-spill-unlikely.html (May 7, 2010).

equation, and if/when prevention fails, there must be swift and effective action to stop the flow of oil at the source.

Blowouts have occurred on a fairly regular basis around Alaska. Contrary to claims that such incidents are rare in Cook Inlet, at least 4 well blowouts have occurred in Inlet waters since 1962, with additional blowouts occurring at shore-based facilities.[2] The passage of legislation (the 'Stampede Act") to induce new drilling through massive government subsidies has increased the risks of a blowout in Cook Inlet, as smaller independents with little experience drilling in Alaska waters race to claim their tax-credit prize while drilling into lesser known formations and pressure regimes. For example, Escopeta's escapades with the Spartan 151 jack-up rig have been well-documented, prompting a rare and serious rebuke from state regulators.[3]

Clearly, a sizable oil spill would wreak havoc on the premier commercial, subsistence and sport fishing economies of Cook Inlet. We need only look back to 1987 grounding of the *T/V Glacier Bay* and the subsequent oil spill that closed local fisheries to understand the fragile balance struck between fisheries management and oil development in Cook Inlet. Nor would the cold water environment of the Inlet soon recover from such an event as evidenced from the still unresolved biological impacts of the Prince William Sound 1989 Exxon Valdez oil spill.[8]

The risks posed by increased oil and gas exploration and development in Cook Inlet mandate the most stringent review and regulation of drilling rigs by the State of Alaska Oil and Gas Conservation Commission. As a means of protecting the unique natural resources of the Inlet and the substantial and sustainable economies they support, the Kachemak Bay Conservation Society (KBCS) recommends that the Commission should require operators drilling offshore or ultra-extended reach wells to demonstrate the ready capability to drill a relief well if necessary and require concurrent relief well drilling in offshore and ultra-extended reach drilling operations as listed in inquiries 11 and 12 of the Notice of Inquiry in reference to Docket OTH-10-16.

In support of this recommendation KBCS submits a document entitled "*Fair Warning: Diminished State Oversight of Oil Spill Contingency Plans*," drafted by Trustees for Alaska in 2006 (enclosed), and provides the additional following comments:

## I. The Commision should require operators drilling offshore or ultra-extended reach wells to demonstrate the ready and actual capability to drill a relief well if necessary.

In early 1990, following the Exxon Valdez oil spill incident in Prince William Sound, the Alaska Oil Spill Commission (AOSC) determined that "[s]tate government was not fully prepared to oversee industry operations" or "to insure proper response capabilities in case of accident." Recognizing that voluntary efforts to prevent oil spills do not translate into a regulatory commitment or responsibility, the AOSC further stated that "[r]egulatory effectiveness … should be improved" because "[p]rivate voluntary

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[2] Our Resources, Our Past, Our Future, AOGCC (2008), p. 91. See also, *A Fair Warning: Diminished State Oversight Of Oil Spill Contingency Plans*, p. 4-5 (February, 2006)(Michael Frank, Esq, Trustees for Alaska)(Fair Warning) (enclosed).

[3] *See., e.g. State Scolds Escopeta for rig*, Peninsula Clarion, Aug. 29, p. 1 (quoting Alaska Division of Oil & Gas Director Bill Barron saying "I am gravely concerned about what I perceive to be Escopeta's apparent disregard for regulatory requirements.").

[8] Rebbecca Luczycki, *The State of the Sound, Twenty Years After the Exxon Valdez Oil Spill, the Recovery of Prince William Sound is Still the Subject of Debate*, Alaska Magazine, p. 22-31 & 75 (September 2009).

prevention measures, though commendable, are often ignored as memories fade unless backed up by state regulations."[9]

As a result of the *Exxon Valdez* incident, therefore, existing laws and regulations in the state of Alaska provide amble precedent for requiring offshore or ultra-extended reach wells to demonstrate the ready capability to drill a relief well at the earliest possible time. Based, in part, on AOSC recommendations,[10] for example, the Alaska legislature strengthened the ability of ADEC to enforce the requirements concerning oil spill contingency plans produced by drilling operators to prevent or control such spills.[11] This was accomplished through the State's enactment of laws that prohibited the operation of an oil terminal facility, pipeline, exploration or production facility, tank vessel or oil barge unless ADEC approved the operator's contingency plan which must ensure that the applicant has access to sufficient resources ... to contain, clean up, and mitigate potential oil discharges from the facility or vessel."[12]

Other state agencies have implemented the Alaska legislature's directives for prevention of blowouts. In the early 1990s, for example, the Department of Environmental Conservation (ADEC) adopted regulations implementing the new contingency planning statutes addressing blowouts of wells at onshore and offshore oil and gas exploration or production facilities.

Similarly, under Alaska state law and ADEC regulations, each blow out prevention contingency plan for marine waters in Alaska must mandate adequate secondary relief well capacity, or similar blow-out prevention and response tools in Cook Inlet. Such plans must include Best Available Technology prevention standards "consistent with the applicable" statutory criteria,[13] including:

> (A) whether each technology is the best in use in other similar situations and is available for use by the applicant;
> (B) whether each technology is transferable to the applicant's operations;
> (C) whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits;
> (D) the cost to the applicant of achieving [BAT], including consideration of that cost relative to the remaining years of service of the technology in use by the applicant;
> (E) the age and condition of the technology in use by the applicant;
> (F) whether each technology is compatible with existing operations and technologies in use by the applicant;
> (G) the practical feasibility of each technology in terms of engineering and other operational aspects; and
> (H) whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits.[14]

ADEC regulations, additionally, require that:

> ... technology used for oil discharge containment, storage, transfer, and cleanup to satisfy a response planning standard...will be considered [BAT] if the technology of the

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[9] State of Alaska, Alaska Oil Spill Commission, *Spill – The Wreck of the Exxon Valdez – Implications for the Safe Transportation of Oil – Final Report*, p. 137, 140 (AOSPC, *Final Report*) (February 1990).
[10] *See* ADEC, *The Exxon Valdez Oil Spill – Final Report, State of Alaska Response* at 156, (June 1993) (ADEC Final Report).
[11] *See,* AOSPC, *Final Report,*at 156.
[12] AS 46.04.030(a)-(c )&(e).
[13] 18 ACC §78.425(e)(4).
[14] 18 AAC §75.445(k)(3).

applicant's oil discharge response system as a whole is appropriate and reliable for the intended use, as well as the magnitude of the applicable response planning standard....[15]

Further, ADEC-approved contingency plans for Cook Inlet must include response strategies demonstrating that:

> ... procedures are in place to stop the discharge at its source within the *shortest possible time* [and] plan strategies are sufficient to meet the applicable response planning standard...for containment, control, recovery, transfer, storage, and cleanup *within the specified time* and under environmental conditions that might reasonably be expected to occur at the discharge site....[16]

Moreover, "...contingency plans must demonstrate the general procedures to clean up a discharge *of any size*, including the greatest possible discharge that could occur...."[17] and the response technologies and strategies in contingency plans must "include...procedures to stop the discharge *at its source and prevent its further spread....*[18]

Finally, that action must be taken to stop blowouts at the earliest possible time is illustrated by the fact that unless "containment or cleanup is technically not feasible; or ...if the cleanup or containment activities would result in greater environmental damage than the discharge itself", any "discharge of oil shall be *immediately* contained and cleaned up..."[19]. A "response action" is defined by statute as "an action taken to respond to a release *or threatened* release of oil, including *mitigation*, cleanup, or removal."[20]

Significant to the timing of relief wells is the definition of "technology;" in the terms Best Available Technology, "technology" is not limited to just "equipment, supplies, [or] other resources" but also includes "*related practices*."[21] In addition, it is clear that spill prevention contingency plans must pay close attention to detail in achieving the highest possible reduction of impacts from blowouts, including a "calculation of the applicable response planning standards...including a detailed basis for the calculation of reductions, if any, to be applied to the response planning standards."[22]

The federal government, in response to the BP Gulf Disaster, recently adopted various NTL provisions related to relief well timing and preparedness for its offshore leases, including:

- A blowout scenario as required by 30 CFR 250.213(g) and 250.243(h). Provide a scenario for the potential blowout of the proposed well in your plan or document that you expect will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum

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[15] *Id.*

[16] 18 AAC §75.445(d)(1) & (5) (emphasis added). These provisions are similar to 18 AAC § 75.445 (d)(2) which provides that exploration or production facility plans must illustrate that "planned methods, equipment, logistics, and time frames [are] in place for controlling a well blowout, within 15 days...."

[17] 18 AAC §75.430(a)(emphasis added).

[18] 18 AAC §75.425(e)(1)(F)(i). Such strategies must "identify all available technologies and include a written analysis of each technology, using the applicable criteria in 18 AAC §75.445(k) (3)" and "include a written justification that the technology proposed to be used is the best available for the applicant's operation." 18 AAC §75.425. (e)(4)(B) and (C).

[19] AS §46.04.020(a) & (d)(emphasis added).

[20] AS §46.04.900(22) (emphasis added).

[21] 18 AAC §75.425(f)(emphasis added).

[22] 18 AAC §75.425.(e)(5).

duration of the potential blowout. Discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Specify as accurately as possible the time it would take to contract for a rig, move it onsite, and drill a relief well, including the possibility of drilling a relief well from a neighboring platform or an onshore location.

- Describe the assumptions and calculations that you used to determine the volume (daily discharge rate) of your worst case discharge scenario required by 30 CFR 250.219(a)(2)(iv) (for EPs) or 30 CFR 250.250(a)(2)(iv) (for DPPs and DOCDs). Provide all assumptions you made concerning the well design, reservoir characteristics, fluid characteristics, and pressure volume temperature (PVT) characteristics; any analog reservoirs you considered in making those assumptions; an explanation of your reasons for using those analog reservoirs; and the supporting calculations and models you used to determine the daily discharge rate possible from the uncontrolled blowout portion of your worst case discharge scenario for both your proposed or approved EP, DPP or DOCD worst-case discharge scenario and your proposed or approved regional (Oil Spill Response Plan (OSRP) worst-case discharge scenario used in your comparison.

- Describe the measures you propose that would enhance your ability to prevent a blowout, to reduce the likelihood of a blowout, and conduct effective and early intervention in the event of a blowout, including your arrangements for drilling relief wells, and any other measures you propose.

These provisions provide a useful starting point for AOGCC, and they should be supplemented, at a minimum, with a requirement that lease holder identify a specific, executed contract showing it can produce a jack-up rig to drill a relief well in the time allotted in the operator's spill contingency plan.

## II. The Commission should consider requiring concurrent relief well drilling in offshore and ultra-extended reach drilling operations

As suggested by the Division of Oil and Gas, perhaps the most frustrating aspect of oil and gas well blowouts is that, in almost every case, they are preventable. In 1969, for example, a blowout, taking months to control, occurred at the Union Oil Company oil and gas production platform about six miles off the coast of Santa Barbara, California, after the U.S. Geological Survey (USGS) granted a waiver of federal piping standards intended to prevent such incidents.[23] The Union Oil accident ultimately resulted in a 100,000-barrel crude oil spill that spread over 800 square miles, oiled 35 miles of coastline, killed or injured thousands of birds and other wildlife, and caused severe adverse impacts to important sectors of California's economy.[24]

Similarly, in addition to the mistaken belief among governmental and industry representatives that such a spill was highly "unlikely," the worst oil well blowout in American history occurred as a result of a failure to apply proper state and federal spill prevention laws, set up safeguards such as testing of blowout prevention measures, require adequate relief wells, and set up adequate oil response measures. The blowout was caused by an explosion on the British Petroleum Company's (BP's) Deepwater Horizon well platform operating in the Gulf of Mexico during the summer of 2010, killing eleven people working on

[23] *See, Fair Warning* at 6.
[24] *Id.*

the platform.[25] The Deepwater Horizon oil spill, which stemmed from a sea-floor oil gusher, flowed for three months releasing an estimated 4.9 million barrels (205,800,000 gallons) or 53,000 barrels (2,226,000 gallons) per day of crude oil from the well before it was finally capped.[26]

The environmental and economic effects of the Deepwater Horizon oil spill are devastating, making it a showcase example of the type of catastrophe that could have been avoided with the proper application of a relief well at the time of, or immediately after, the blowout occurred. Instead, the well spewed oil for months after the blowout and secondary relief well drilling was not timed to limit the amount of oil spilled.[27]

Although not to the scale of the BP and Union Oil incidents, Alaska has experienced it's share of well blowouts. In 1985, for example, Union Oil's Grayling Platform spilled oil into Cook Inlet over the course of three days as the result of a short-term natural gas blowout while drilling a well into the McArthur River Field.[28] As the company prepared to drill a relief well, in a process called "bridging", the blowout stopped when the bedrock formation around the well bore collapsed into the bore.[29]

Similarly, in December 1987, a blowout occurred in the Cook Inlet McArther River Field when Marathon Oil's Steelhead Platform well continuously spewed natural gas, water, coal, and rocks into Cook Inlet for a period of 18 months. [30] In part, due to the time it took to complete a relief well, escaping gas from the blowout caught fire which damaged the deck of the platform and caused some injuries as workers attempted to stop the spill.[31]

While the state of Alaska and industry have experience in containing smaller oil or gas blowouts, it is clear they are not prepared for a well blowout of the magnitude of the one that occurred in the Gulf. When a series of eruptions from Mount Redoubt, which boarders the Inlet, occurred from March 22 to April 4, 2009, for example, the resultant volcanic mudflows caused extensive flooding at the Drift River Oil Terminal (DROT).[32] Although the six million gallons of oil stored at the DROT, ultimately, did not discharge into the Inlet as a result of the incident, subsequent review indicated that such a spill, with it's incalculable threats to Cook Inlet fisheries, nearly did occur, primarily, due to a combination of ADEC's failure to notify the public of the risk and the lack of a catastrophic spill contingency plan.[33]

Further raising the risk of an oil spill and/or blowout in Cook Inlet is the fact that some platforms, undersea pipelines, and terminals operating in the Inlet have been in production for decades,[34] and

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[25] http://www.care2.com/causes/10-most-horrifying-facts-about-the-gulf-oill-spill.html.
[26] http://en.wikipedia.org/wiki/Deepwater_Horizon_oil_spill.
[27] www.nature.com/news/2011/110114/full/news.2011.54.html.
[28] http://www.adn.com/2008/12/18/628170/details-of-alaska-blowouts.html.
[29] DOG Final Finding at Chapter 5.C.1.
[30] http://www.incidentnews.gov/incident/6537.
[31] *Id.*
[32] http://www.dec.state.ak.us/spar/perp/response/sum_fy09/090324201/090324201_index.htm.
[33] *See,* Cook Inletkeeper, *Spill Prevention and Response Break-Downs Show that Lessons Learned from the Exxon Valdez Oil Spill Don't Apply in Cook Inlet* (August 24, 2009). According to Cook Inletkeeper, ADEC and the U.S. Coast Guard allowed:

> Chevron to withhold from the public the volume of oil at the Drift River Terminal when Mt. Redoubt became active in early 2009, even though such information is made public on a daily basis at the Valdez Marine terminal. Had the oil volume been made public, it would have been clear prior to Mt. Redoubt's initial eruption that spill response equipment in Cook Inlet could not address a catastrophic release.

[34] *See e.g.*, Comments of Kachemak Bay Conservation Society on Escopeta Oil Discharge Prevention and Contingency Plan (ODPCP) for Cook Inlet Exploration Program Plan No. 11-CP-5184, p.3 (May 19, 2011) .

sufficient equipment and personnel needed to respond to a multiple spill scenario remain unavailable.[35] The primary means of preventing such incidents and the resulting catastrophic effects on sensitive ecosystems, particularly in marine and coastal environments, is for all of these facilities to develop ADEC-approved contingency plans properly utilizing BAT. The risk of a well blowout is obviously much higher when the responsible regulatory agencies are not vigilant in their oversight of such plans and other oil and gas activities.

Even now, as communities and fish and wildlife populations are attempting to recover from the tragedy in the Gulf, oil and gas companies together with state agencies in Alaska are balking at stronger BAT and other accident prevention standards. Escopeta Oil's central argument, for example, for weakening blow out prevention standards is "the circumstances for such an event are unlikely."[37]

Such conclusions, however, are eerily similar to the apathetic rationalization adopted by industry and government managers just before the Gulf Oil spill. In fact, prior to the spill, the Interior Department failed to impose a full review of potential environmental impacts of the BP drilling operation because preliminary reviews of the area concluded that a massive oil spill was "unlikely."[38] Just three months later, when BP submitted its Gulf drilling plans to the Minerals Management Service, the agency chose to ignore the detailed environmental review required by the National Environmental Policy Act by declaring the plan to be "categorically excluded" from environmental analysis because it posed virtually no chance of harming the environment.[39] Similarly, in the course of approving a plan to drill in the delicate Beaufort and Chukchi seas of Alaska, Secretary Salazar accepted the Shell Oil Corporations conclusion that "a large oil spill, such as a crude oil release from a blowout, is extremely rare and not considered a reasonably foreseeable impact."[40]

Unfortunately, the "unlikeliness" strategy for blowout prevention is already making an appearance in Cook Inlet. In relation, for example, to the Army Corp of Engineer's (Corps) request for concurrence under the ESA that Escopeta Oil, Inc.'s permit to drill exploratory oil/natural gas wells within Cook Inlet may affect, but is not likely to adversely affect, the endangered Cook Inlet beluga whale or it's critical habitat, the NMFS admonishes the Corps to consider factors other than the low probably of a major blowout. NMFS states:

> While the Corps has analyzed potential impacts from noise and developed mitigation accordingly, we have received only qualitative information concerning potential impacts from oil spills. If a large or catastrophic (i.e., greater than 1,000 or 150,000 barrels of oil, respectively) oil spill were to occur, there is the potential for adverse effect to beluga whales and their critical habitat from exposure to the oil. While we may agree *that there is a low likelihood of a large or catastrophic oil spill*, the Corps has not demonstrated that the effects from such a spill are discountable.... As a result, we cannot concur that

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[35] In fact, only two of the twelve offshore production platforms now operating off and on in the northern Inlet, was installed after 1967. For the Kenai Peninsula Borough's history of Cook Inlet oil and gas development and a map showing the existing fields and facilities, *see* http://www.cookinletoilandgas.org/kpb/history.htm.

[37] Cook Inlet unlikely scene for Gulf coast-like disaster By Dante Petri | Peninsula Clarion. "It's night and day," said Todd Paxton, the general manager at Nikiski-based Cook Inlet Spill Prevention and Response Inc., comparing production in the deep waters of the gulf and the shallow upper Cook Inlet. "They're drilling in 5,000 feet of water. That's much deeper than what we have in Cook Inlet, of course, and the technology those types of platforms have is just about 180 degrees of what we use." Paxton said that aside from the different geologic formations being tapped, the age of Cook Inlet's reserves would likely play into how much oil could be spilled."

[38] http://www.care2.com/causes/doi-concluded-massive-spill-unlikely.html.

[39] Michael Tolbert, Regional Supervisor, Field Operations, United States Department of Interior, Mineral Management Service, Letter to Sharis Douglas, BP Exploration and Production, Inc. (April 6, 2009).

[40] http://www.care2.com/causes/doi-concluded-massive-spill-unlikely.html.

> the proposed action is unlikely to adversely affect the Cook Inlet beluga whale or its critical habitat. In other contexts, action agencies have provided NMFS with oil spill risk analysis addressing risks from different size spills, oil spill trajectory simulations, and conditional probabilities of contact. In light of our experience regarding the Deepwater Horizon oil spill, we cannot discount oil spill risks without a thorough understanding of those risks and an analysis of oil spill responses capabilities and effectiveness.[41]

The Commission should, therefore, consider requiring concurrent relief well drilling in offshore and ultra-extended reach drilling operations because such strategies are the most effective method of stopping a blowout before they can reach catastrophic levels. In fact, the methods most often used for preventing blowouts – "capping"[42] and "pumping drilling mud and/or reactant materials into the capped blowout well"[43] are, not always, practical or reliable. ADEC, itself, for example, provides "[e]ven a successful well capping operation...*does not necessarily signify that the blowout is under control*. If a well kill is not likely to be successful, even when capped or if a blowout well cannot be capped, then other methods must be used."[44] In addition, "[t]he time required to stop or kill a blowout could take between 10 and 30 days if well capping techniques can be used" at all.[45]

Although Alaska state regulations appear to require the immediate drilling of a relief well and such strategies are often the most effective means of stopping blowouts before they turn into environmental and economic disasters, usually, any reference by state agencies to such wells as a practice method for blowout prevention or control is noticeably absent.[46] Even though for purposes of BAT, for example, "technology" means "equipment, supplies, other resources, and *related practices*",[47] during the 2004 Best Available Technology Conference in Anchorage, sponsored by ADEC, for example, relief wells were not even included in the list of technologies presented at the conference.[48]

The omission of relief wells from the discussion related to technologies for blowout control in Alaska is probably due to the conclusion of state agencies and industry that such methods can only "indirectly" control,[49] and constitute the last resort for, a well blow-out.[50] ADEC's reference to relief wells "when all else fails", however, seems to acknowledge that such methods are, more often then not the only directly, effective means of preventing and/or controlling blowouts. Indeed, particularly in Cook Inlet, it appears that relief wells should be the first, rather than a last resort since "[w]hen all else fails, a relief well, drilled to intersect the blowout well, may be the *only option*"[51] and in "some instances, the

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[41] James W. Balsinger, Letter to Commander, Alaska District U.S. Army Corps of Engineers, RE: Section 7 Consultation on Exploratory Drilling Proposal in Cook Inlet, Alaska, p. 3 (July 14, 2011)(emphasis added).

[42] Well capping involves severing the well head and the damaged blowout preventer (BOP) and the installation of a well capping stack. The time required may be from several minutes to several days. Access to the well head may initially require days of clearing away debris. ADEC Best Available Technology, 2004 Conference, Final Report, p. 12 June 2006 (AEDC BAT Report).

[43] *Id.* at 14.

[44] *Id.* (emphasis added).

[45] *Id.* According to ADEC, "[t]he time required to cap a well may be from several minutes to several days. Access to the well head may initially require days of clearing away debris." *Id.* at 12.

[46] 18 AAC §75.425(f)(emphasis added), the ADEC Evaluation Committee for Category 5, for example, refers to "...tools utilized during well control operations, including capping, were evaluated by the committee" and does not include relief wells or any other "related practices." ADEC BAT Report at 53.

[47] *See,* 18 AAC §75.425(f)(emphasis added)

[48] *See e.g.*, ADEC BAT Report at Table of Contents

[49] *Id.* at 15.

[50] *Id.* at 14 (emphasis added).

[51] *Id.* (emphasis added).

only practical way to control a well blowout, *particularly for offshore platforms…*, is to drill a relief well."[52]

In short, AOGCC should embrace the requirements imposed by Canada to require same-season relief well capacity, with a presumption during the relatively short summer drilling season that relief well drilling must be concurrent with exploration drilling. Although industry has pushed back on this common-sense requirement,[53] it's the most sensible way to achieve BAT and to protect Alaskan resources in a balanced manner.

**Conclusion**

Cook Inlet is home to a multitude of fish and wildlife species including the beluga whale which is protected under the federal Endangered Species Act. Additionally, Alaska state regulations make plain that oil and gas blowout prevention planning must cover all aspects of preventing and responding to an oil spill. As such, the state regulation and practicalities clearly call for the drilling of relief wells immediately after the original well for prevention of oil and gas drilling accidents including blowouts. Regardless of these mandates, Alaska state agencies with the support of the oil and gas industry, have diluted the oil spill prevention standards and created confusion regarding the use of relief wells by, on the one hand, concluding that relief wells should be applied to prevent and control blowouts only as a "last resort" while, at the same time, implying the such efforts are often the only means of "practically" controlling blowouts especially for off shore platforms.

At a minimum, AOGCC should conclude that BAT includes the presence and public examination of an executed contract for jack-up rig services to ensure same-season relief well capacity in Cook Inlet and beyond.

Please contact me at (907)299-8821; kbayconservation@g-mail.com if you have any questions regarding these comments and recommendations. Thank you.

Sincerely,

Hal Shepherd, Oil and Gas Project Coordinator

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[52] *Id.* at 15 (emphasis added).

[53] *See., e.g.,* http://www.theglobeandmail.com/report-on-business/oil-giants-contest-arctic-relief-well-requirement/article1972323/

**A FAIR WARNING:**
**DIMINISHED STATE OVERSIGHT OF OIL SPILL CONTINGENCY PLANS**
**FEBRUARY, 2006**

The purpose of this memorandum is to highlight changes the Alaska Department of Environmental Conservation ("ADEC") has made in its program for oil spill contingency planning. These changes have weakened oil spill discharge prevention and contingency planning standards and ADEC's oversight of the oil industry's preparedness.

In the summer of 2004, the Murkowski Administration adopted amendments to Alaska's oil spill contingency planning regulations. These regulatory amendments severely weakened them in crucial respects. To make matters worse, in the past few years ADEC has misinterpreted Alaska statutes and its own regulations so as to weaken contingency planning requirements further.

These actions could lead to an environmental disaster in the event of a major oil spill, especially in Cook Inlet and in the Beaufort Sea. In these waters, offshore oil and gas production platforms operate and subsea oil and gas pipelines service them. During significant portions of the year, sea ice and adverse weather conditions make containing and cleaning up oil spills virtually impossible. In fact, containment and cleanup is highly problematic in these waters under even the best of weather conditions.

Because of the potentially disastrous consequences of ADEC's actions, it is important that the reasoning underlying them be scrutinized. Before doing that, however, is first worth looking back at what happened immediately after the T/C Exxon Valdez oil spill.

THE T/V EXXON VALDEZ OIL SPILL DISASTER PROMPTS TOUGHER LAWS.

The T/V Exxon Valdez ran aground shortly after midnight on March 24, 1989. The huge tanker immediately began spilling crude oil into Prince William Sound. ADEC and the U.S. Coast Guard quickly decided that limiting the volume of oil that could be released should be the top priority in the initial response to the spill. Within just a few hours after the grounding, therefore, the agencies authorized another Exxon tanker already inbound to Valdez to discharge its oily ballast water into the Sound and to begin lightering oil off the T/V Exxon Valdez. Lightering began that night, eventually involved three tankers, and continued for eleven days, until 1,030,000 barrels of crude oil were transferred off the T/V Exxon Valdez onto other tankers. Offloading this oil prevented it from joining the 260,000 barrels (11,000,000 gallons) the T/V Exxon Valdez spilled into the Sound.[1]

[1] ADEC, *The Exxon Valdez Oil Spill – Final Report, State of Alaska Response* (June 1993), at ix, 92.

Just a few weeks later, ADEC issued an Emergency Order to Alyeska Pipeline Service Company, the operator of the trans-Alaska Pipeline System and the crude oil storage and tanker loading facilities in Valdez. Among other things, the Order set specific planning standards for lightering oil from a stricken Prince William Sound tanker involved in any future spill.[2]

Both ADEC's action in focusing first on lightering oil off the T/V Exxon Valdez spill and its Emergency Order demonstrate that from day one of that spill, ADEC considered mitigation of the threat of any additional release of oil to be a critical part of the initial response to a spill.[3]

In reaction to the T/V Exxon Valdez disaster, in the early 1990s the Alaska Legislature enacted legislation that revised contingency plan requirements, specified volumetric oil spill planning response standards, and strengthened ADEC's ability to enforce the requirements concerning contingency plans.[4] Many of these statutory changes were based upon recommendations the Alaska Oil Spill Commission had made early in 1990.[5] After it examined the events that led to the T/V Exxon Valdez disaster, the Alaska Oil Spill Commission had found that "[s]tate government was not fully prepared" to "oversee industry operations ... and to insure proper response capabilities in case of accident," and that "[r]egulatory effectiveness ... should be improved" because "[p]rivate voluntary prevention measures, though commendable, are often ignored as memories fade unless backed up by state regulations."[6]

The new, tougher Alaska laws prohibited the operation of an oil terminal facility, pipeline, exploration or production facility, or tank vessel or oil barge unless the operator first received the approval of an contingency plan from ADEC.[7] The new laws charged ADEC with "ensur[ing] that the applicant for a contingency plan has access to sufficient

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[2] *Id.* 93.

[3] Stopping the ongoing discharge is the well-accepted second goal of the oil spill response strategy. The first goal is to maintain the safety of human life. *See, e.g.*, U.S. Department of Commerce, National Oceanic & Atmospheric Administration, *Strategies & Guidelines for Selecting Response Methods*, at 7, (available at http://response.restoration.noaa.gov/oilaids/ response/response.html (last visited Dec. 20, 2005)) (emphasis added) ("Generally, oil spill response goals, in order of priority, are: 1. Maintain safety of human life; 2. *Stabilize the situation to preclude it from worsening*; and 3. Minimize adverse environmental and socioeconomic impacts by coordinating all containment and removal activities to carry out a timely, effective response."); *see also* 40 C.F.R. § 300.305(d) (U.S. Environmental Protection Agency's National Contingency Plan requiring immediate removal of discharged substances and mitigation of any threatened discharge).

[4] *See* ADEC, *The Exxon Valdez Oil Spill – Final Report, State of Alaska Response*, at 156.

[5] *See* State of Alaska, *Alaska Oil Spill Commission, Spill – The Wreck of the Exxon Valdez – Implications for the Safe Transportation of Oil – Final Report* (February 1990).

[6] *Id.* 137, 140.

[7] *See* AS 46.04.030(a)-(c).

resources ... to contain, clean up, and mitigate potential oil discharges from the facility or vessel . . . ."[8] The Legislature defined containment and cleanup to include "all direct and indirect efforts associated with the prevention, abatement, containment, or removal of a pollutant . . . ."[9] It defined "discharge" to mean any "spilling, leaking, pumping, pouring, emitting, emptying, or dumping . . . ."[10] These definitions were intentionally broad. The definitions made plain that a contingency plan had to cover all aspects of responding to an oil spill.

The Legislature also understood, however, that under the new requirements for contingency plans, vessel, barge and facility operators might have to rely upon experienced oil spill response contractors to supply the personnel and resources needed in a spill response. Thus, in the new law the Legislature specified that the holder of an approved contingency plan could either "maintain or have available under contract" sufficient resources to meet the applicable response planning standard.[11] To ensure that any promised contractual services would actually be performed, the Legislature forbade ADEC from approving a contingency plan that relied upon the services of an "oil spill primary response action contractor" unless the contractor was first registered and approved by ADEC.[12]

WELL BLOWOUTS

In the early 1990s, ADEC adopted regulations implementing the new contingency planning statutes. Among the more significant regulations was one concerned with the possible blowouts of wells at onshore and offshore oil and gas exploration or production facilities. A blowout occurs when a well builds up sufficient gas pressure at the bottom of the well to overcome the hydrostatic weight in the well, and the gas forces its way to the ground surface carrying with it a plume of crude oil.[13]

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[8] *Id.* (e).

[9] AS 46.04.900(5) (emphasis added). "Abatement" is not defined in the Alaska Statutes, but its common dictionary definition is "put an end to," e.g., putting an end to the ongoing discharge of oil. *Webster's New Encyclopedic Dictionary* 2 (Merriam Webster, Inc., 2002).

[10] AS 46.04.900(7).

[11] *See* AS 46.04.030(k); *see also* 18 AAC § 75.434(a).

[12] *See* AS 46.04.030(e); *see also* AS 46.04.035(g)(2) (defining a "primary response action contractor" as "a person who enters into a response action contract" for a spill and "who is carrying out the contract "), and 18 AAC § 75.500 (defining a "response action contractor" similarly).

[13] The Alaska Department of Natural Resources, Division of Oil and Gas, describes a well blowout as follows:

> The most dramatic form of spill can occur during a well blowout which occurs when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud have not been taken (Williams and Meyers, 1981). The result is that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers which immediately close off the open well and prevent or minimize any

Blowouts are a primary cause of well head fires and a drilling operator's loss of control over a well.[14] Knowing this, drilling rig companies apply operational practices and install mechanical devices that are intended to prevent blowouts from happening. The State of Alaska's Oil and Gas Conservation Commission supervises these practices and sets standards relevant to the mechanical devices.[15] The Commission, however, lacks authority to approve or otherwise regulate the contents of contingency plans. Oversight of contingency plans is solely the province of ADEC.[16]

Well blowouts are not that uncommon, at least in other states.[17] Luckily, in modern times a blowout causing a major crude oil spill has rarely occurred in Alaska.[18]

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> discharges, are required for all drilling and work-over rigs, and are inspected routinely by the AOGCC.

State of Alaska, Division of Oil and Gas, Department of Natural Resources, *Cook Inlet Areawide Oil and Gas Lease Sale Final Finding of the Director* (Jan. 20, 1999), Chapter 5.C.1. *See also Anderson-Prichard Oil Corp. v. Parker*, 245 F.2d 831, 836 (10th Cir. 1957) (describing a well blowout).

[14] *See Atlantic Richfield Co. v. Underwriters at Lloyd's of London*, 398 F.Supp. 708, 716 (D.C. Tex. 1975).

[15] *See* 20 AAC §§ 25.005 - .080, §§ 25.200 - .290 (Alaska Oil and Gas Conservation Commission drilling and production regulations, including one covering blowout prevention devices at § 25.035).

[16] *See* AS 46.04.030(h) (ADEC "is the only state agency that has the power to approve, modify, or revoke a contingency plan").

[17] *See, e.g.*, the Texas Railroad Commission's listing of events in *Blowouts and Well Control Problems* at http://www.rrc.state.tx.us/divisions/og/blowouts-mm/allblowoutspg1.html (last visited Dec. 20, 2005), and the California Department of Conservation, Division of Oil, Gas and Geothermal Resources's *A History of Oil and Gas Well Blowouts in California 1950 – 1990, Publication No. TR43*, at http://www.consrv.ca.gov/DOG/pubs_stats/archived_pages/technical_reports1.htm (last visited Dec. 20, 2005). The latter document also contains a lengthy discussion of the circumstances under which a well blowout occurs. *Id.* 1-2.

The Alaska Oil and Gas Conservation Commission does not maintain a listing of well control or blowout problems that have occurred in Alaska. Email from AOGCC to Trustees for Alaska (Feb. 1, 2005, 1:17 AST) (on file with Trustees for Alaska). The Commission's regulations do require an operator to report any use of blowout preventer equipment or any uncontrolled release of oil or gas within reporting thresholds of 10 barrels of oil and 1,000 mscf of gas. *See* 20 AAC § 25.205 and §§ 25.035(e)(11) and 25.036(g).

[18] A well blowout occurred from the Discovery Well in Katalla, Alaska, a "gusher that sprang from the bowels of the earth in September of 1902 rose 85 feet in the air, and flowed at an estimated rate of 1,600 barrels per day."[18] Janson, Lone, THE COPPER SPIKE, at 25 (1975). The blowout caused a major spill at the mouth of the Katalla River, a prime salmon spawning ground and migratory bird habitat.

According to a 1999 finding for a Cook Inlet oil and gas leasing sale made by the State of Alaska's Division of Oil and Gas:

> A blowout that results in an oil spill is extremely rare and none are known to have occurred in Alaska. However, natural gas blowouts have occurred. The Pan American blowout occurred offshore in August 1962 when the well, Cook Inlet State No. 1, was being drilled from a barge located eight miles east and two north of North Forelands. The well encountered natural gas and

It is, of course, costly for an operator to remain fully prepared to respond to the

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> blew gas from August 23, 1962 to October 23, 1963. Pan American Petroleum Corporation drilled a relief well, No. 1-A, to stop the blowout.
>
> The Grayling Platform experienced a short-term natural gas blowout in May 1985. Union Oil Company was drilling well G-10RD into the McArthur River Field when the blowout occurred. The event lasted from May 23 to May 26. The platform was evacuated, and observers noted a plume of gas, water and mud reaching a height of 600 feet above sea level. Union prepared to drill a relief well, but the blowout stopped on its own because of bridging. Bridging seals off the escaping fluids and gases when part of the formation around the well bore collapses into the well bore and naturally closes it. The operator regained permanent well control by pumping cement through the drill pipe in G-10RD. There was no fire nor injuries, and personnel shut-in all oil wells prior to evacuating the platform.
>
> The last reported blowout in Cook Inlet occurred when the Steelhead Platform well, M-26, encountered natural gas in December 1987. Marathon Oil Company was drilling into the McArthur River Field. The gas blowout lasted from December 1987 until June 1988. A relief well was started but the blowout bridged before the relief well was completed. The well blew out natural gas, water, coal, and rocks. The escaping gas caught fire which damaged the deck of the platform, and some injuries occurred as workers attempted to stop the blowout.
>
> A worst case discharge from an exploration or production facility is restricted by the maximum storage capacity of the facility or vessel or by a well's ability to produce oil. For example, a well with a production rate of 2,500 bbl per day can only spill a maximum of 2,500 bbl per day. There never has been a major oil spill (1,000 bbl or greater) from activities associated with the exploration, development, or production facilities in Cook Inlet.

State of Alaska, Division of Oil and Gas, Department of Natural Resources, *Cook Inlet Areawide Oil and Gas Lease Sale Final Finding of the Director* (Jan. 20, 1999), Chapter 5.C.1. Similarly, for a 1999 Beaufort Sea oil and gas lease sale the Division of Oil and Gas stated:

> A blowout that results in an oil spill is extremely rare and has never occurred in Alaska. However, natural gas blowouts have occurred. From 1974 to 1997 an estimated 3,336 wells were drilled on the North Slope. There have been six documented instances of loss of secondary well control with a drill rig on the well. This equates to 1.8 blowouts per 1000 wells (Mallary, 1998). A gas blowout occurred in 1992 at the Cirque No. 1 well. The accident occurred while ARCO workers were drilling an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took two weeks to plug the well (Anchorage Times, 1992). In 1994, a gas kick occurred at the Endicott field 1-53 well. BPX was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was killed three days later by pumping heavily-weighted drilling muds into it (Schmitz, 1994; Anchorage Daily News, 1994a).

State of Alaska, Division of Oil and Gas, Department of Natural Resources, *Beaufort Sea Areawide Oil and Gas Lease Sale Final Finding of the Director* (July 15, 1999), at 6-22 to 6-23.

ADEC's listing of "major oil spills to coastal waters" in Alaska includes two relatively recent spills at the Steelhead and Marathon Spark offshore oil and gas production platforms in Cook Inlet. *See* http://www.state.ak.us/dec/spar/ perp/bigspills.htm (last visited Jan. 13, 2005). The Steelhead platform had a large explosion in 1987. *See* http://www.cookinletoilandgas.org/kpb/ history.htm (last visited Jan. 13, 2005).

possibility of a disastrous event that may only infrequently occur. But, as in the case of a large tanker spill, when a well blowout occurs the environmental, economic and social consequences are likely to be catastrophic, justifying the preparedness expense.[19]

To illustrate, in 1969, a well blowout occurred at a Union Oil Company oil and gas production platform about six miles off the coast of Santa Barbara, California. The blowout occurred after the U.S. Geological Survey had granted Union Oil Company a waiver of federal piping standards intended to prevent blowouts.[20] The blowout caused a 100,000-barrel crude oil spill. The spill spread over 800 square miles, oiling 35 miles of coastline, killing or injuring thousands of birds and other wildlife, and causing severe adverse impacts to important sectors of California's economy. Oil company workers took over eleven days to control the leaking well, although another leak sprung up weeks later, releasing oil for months to follow. Luckily, the oil and gas production platform did not explode into fire and entirely prevent the well control effort.

In addition to many *on*shore oil and gas production facilities on the North Slope and in the Kenai Peninsula Borough, Alaska also has a number of *off*shore oil and gas production facilities. In the Arctic Ocean's Beaufort Sea, the Northstar oil and gas production facility, owned by British Petroleum Alaska, Inc., began operations in 2002.[21] In Cook Inlet there are twelve offshore production platforms now operating off an on. One was installed in 1986 and another in 2002, but the rest were installed between 1964 and 1967.[22] In order to operate, all of these offshore facilities must have contingency plans approved by ADEC. In addition, ADEC periodically approves contingency plans for mobile oil and gas exploratory platforms. As long as offshore, and onshore, exploration and production facilities like these operate in Alaska, they pose a risk of a well blowout that would likely have catastrophic effects on sensitive ecosystems, particularly marine and coastal ones. The risk of a well blowout obviously will be much higher if the responsible regulatory agencies are not vigilant in their oversight.

ADEC WEAKENS OVERSIGHT OF CONTINGENCY PLANS.

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[19] For a visual tour of an oil well blowout that occurred recently in Louisiana, *see* the National Oceanic and Atmospheric Administration site for the East Timbalier Island blowout at http://www.photolib.noaa.gov/habrest/gos.htm (last visited Dec. 20, 2005). (NOAA's collection of spill incident photos from around the world can be accessed at http://photos.orr.noaa.gov/index.htm (last visited Dec. 20, 2005).) A 2003 gas well blowout in mainland China killed nearly 200 people. *See* http://www.chinadaily.com.cn/en/doc/2003-12/25/content_293409.htm (last visited Dec. 20, 2005).

[20] For information on the Santa Barbara well blowout, *see* http://www.silcom.com/~sbwcn/spill.shtml, http://www.countyofsb.org/energy/information/1969blowout.asp, and http://www.geog.ucsb.edu/~kclarke/Papers/SBOilSpill1969.pdf (all last visited Dec. 20, 2005).

[21] Another "offshore" facility in the Alaska Arctic is located at Endicott, but that facility is connected to the mainland by a manmade causeway. The Northstar facility is completely offshore. Undersea, buried pipelines lead from the Northstar facility to the shore.

[22] For the Kenai Peninsula Borough's history of Cook Inlet oil and gas development and a map showing the existing fields and facilities, *see* http://www.cookinletoilandgas.org/kpb/history.htm (last visited Dec. 20, 2005).

Until recently, ADEC's regulations required each well operator to include within its contingency plan a plan and time frame for controlling a well blowout, including provisions for drilling a relief well.[23] Unfortunately, during the Knowles Administration ADEC began interpreting its well blowout and contractor regulations in a manner inconsistent with the letter and spirit of Alaska's protective contingency planning statutes.

The first of ADEC's weakening changes occurred when ADEC decided it could approve contingency plans that relied on well blowout control services provided by independent contractors that were not registered with ADEC. In order to reach that result, ADEC decided that "well capping contractors do not provide containment, control, or cleanup of a spill."[24] To decide that, ADEC had to conclude that controlling a well blowout was *not* a "response action" under the contractor registration statute.[25] However, a "response action" is defined as "an action taken to response to a release or *threatened* release of oil, including *mitigation*, cleanup, or removal,"[26] and a "primary response action contractor" is anyone "who enters into a response action contract with respect to a release *or threatened release* of oil and who is carrying out the contract."[27] Thus, not

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[23] ADEC's regulation required that the contingency plan include

> response strategies. . . [that] must demonstrate that
> (1) procedures are in place to stop the discharge at its source within the shortest possible time;
> (2) *for an exploration or production facility, plans and time frames are in place for controlling a well blowout, including provisions for drilling a relief well*, taking into account any seasonal environmental conditions that might reasonably be expected to preclude emergency operations from regaining control of well pressure . . . .
> (5) plan strategies are sufficient to meet the applicable response planning standard established under 18 AAC 75.430 - 18 AAC 75.442 for containment, control, recovery, transfer, storage, and cleanup within the specified time and under environmental conditions that might reasonably be expected to occur at the discharge site;

18 AAC § 75.445(d)(1) and (2) (2003) (emphasis added). A "response action" is defined by statute as "an action taken to respond to a release *or threatened* release of oil, including *mitigation*, cleanup, or removal." AS 46.04.900(22) (emphasis added).

[24] *See* Email from ADEC's Lydia Miner to Trustees for Alaska (Nov. 27, 2002, 09:53 A.M. AST) *Subject: Concoco Phillips ADEC Plan No. 024-cp-5096* ("As our letter indicates, well capping contractors do not provide containment, control, or cleanup of a spill") (copy on file with Trustees for Alaska).

[25] *See, e.g.*, Letter from Trustees for Alaska to Bill Hutmacher, Program Manager, DEC, *Re: Forest Oil Corporation's Oil Discharge Prevention and Contingency Plan for Cook Inlet Area Production Operations Alaska* (Dec. 23, 2002) at 1, and Letter from Stephen W. Geddes, ADEC C-Plan Support Specialist to Trustees for Alaska *Re: Comments on ConocoPhillips' Oil Discharge and Contingency Plan Amendments for Puviaq #1 and #2; ADEC Plan No. 024-CP-5096* (September 21, 2002), at 3-4.

[26] AS 46.04.900(22) (emphasis added). "Mitigation" is not defined in AS 46.04. A common dictionary definition of mitigate is "to cause to become less harsh or hostile" and "to make less severe or painful." *Webster's New Encyclopedic Dictionary* 1173 (Merriam-Webster, Inc. 2002).

[27] AS 46.04.035(h)(2) (emphasis added).

only does ADEC's astonishing conclusion that controlling a well blow out is not a response action defy common sense, it conflicts with these two statutory definitions.

ADEC's conclusion also directly contradicts its own regulatory definition of a "primary response action contractor." A "primary response action contractor" is defined in ADEC's regulation as a "person who is or intends to be obligated under contract ... to provide resources or equipment to *contain*, *control*, or clean up an oil discharge"[28] It is obvious that stopping a well from releasing additional oil after a blowout occurs is within the definition of containing and controlling the oil discharge.[29] Indeed, ADEC's current interpretation of its own regulation is directly at odds with how ADEC said its regulation would be interpreted when ADEC adopted it back in 1993. Then, ADEC stated that a well control contractor would be considered a primary response action contractor:

> Sentence 2 has been reworded to specify that contractors who provide resources not for the specific purpose of containing, controlling, or cleaning up a discharge are not PRACs. *This change clarifies that a relief-well drilling company contracted to the plan holder would be considered a ... [primary response action contractor] under the regulations.*[30]

The contingency planning statutes require that the holder of an approved contingency plan either maintain or have available under contract sufficient resources to meet the applicable response planning standard.[31] However, under ADEC's misinterpretation of the applicable law, before approving a contingency plan it is no longer required to make sure the oil company holding the plan has entered into a binding contract with an experienced contractor that has sufficient personnel and equipment ready to stop an ongoing discharge from a well blowout. When ADEC does not perform its duty to approve a well control contractor that the plan holder intends to rely upon, or to make sure there are binding contractual arrangements between the well control contractor and the plan holder, ADEC fails to ensure that the plan holder will be able to meet the response planning standard.[32]

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[28] 18 AAC § 75.500(a) (emphasis added). It is worth noting that this regulatory definition comports with the statutory definition of "response action."

[29] *See* AS 46.04.900(5) (" 'containment and cleanup' includes all direct and indirect efforts associated with the prevention, abatement, containment, or removal of a pollutant, and the restoration of the environment to its former state").

[30] ADEC letter, enclosure to interested parties, (June 15, 1993), at 2 (emphasis added).

[31] *See* AS 46.04.030(k); *see also* 18 AAC § 75.434(a).

[32] Another adverse effect of ADEC's misinterpretation of applicable relates to liability. If named in a contingency plan, a primary response action contractor becomes liable for remove costs or damages in the event it fails to respond to a spill as required by its contract with the contingency plan holder. *See* AS 46.03.825(b)(2)(C). By exempting responders that provide well capping or other well blowout control services from the requirement to register under AS 46.04.035, ADEC may be inadvertently providing them an argument that they are immune from costs or damages liability no matter how badly they perform response services during a spill.

To claim, as ADEC now does, that well control blowout services have nothing to do with the containment or control of an oil spill ignores the fundamental principle of spill response: after ensuring human safety, the first and most important step that responders must take is to stop the continuing discharge of oil at its source. That is the service that well blowout control contractors provide: they control the blowout and stop the discharge at its source. To exempt them from regulation makes no sense and is inconsistent with Alaska law.

NEW ADEC REGULATIONS IN 2004 CREATE MORE LOOPHOLES.

In 2004 ADEC formalized its erroneous interpretations of applicable law by amending its regulations. These amendments, which became effective on May 24, 2004, eliminated the requirement that contingency plans include a complete plan for controlling a well blowout. Now the regulations only require that the applicant for approval of a proposed contingency plan submit a "summary" of what the holder of the plan intends to do in the event of a blowout.[33] While the amended regulations give ADEC the option to request and inspect the well blowout plan, during the contingency plan review process the public has no right to review and comment on the well blowout plan. Indeed, there really is no way for the public to know whether the well blowout plan exists unless ADEC asks the applicant to produce it and then makes the plan available to the public for review.

Since ADEC does not treat well blowout control as a "response action," under its amended regulations ADEC is not requiring the plan holder to include a simple statement of contractual terms confirming that the plan holder has a binding contract requiring the well control contractor to respond in the event of a well blowout. This means that for well blowouts, the plan holder now regulates itself.

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[33] The amended *application* regulation requires that the applicant submit only a

> summary of planned methods, equipment, logistics, and time frames proposed to be employed to control a well blowout within 15 days; the plan holder shall certify that the plan holder maintains a separate blowout contingency plan; the blowout contingency plan is not part of an application required under [c-plan application, amendment, and renewal procedures], but must be made available to the department for inspection upon request.

18 AAC § 75.425(e)(1)(I). The amended *approval* regulation requires that a contingency plan include only a

> summary of planned methods, equipment, logistics, and time frames in place that provide for the control of a well blowout within 15 days; the plan holder shall certify that the plan holder has a blowout contingency plan and shall make the blowout contingency plan available to the department for inspection upon request under 18 AAC 75.480 [c-plan inspection regulations]; [ADEC] may consult with the Alaska Oil and Gas Conservation Commission , the Department of Natural Resources, or other agencies to determine the adequacy of the planned methods, equipment, logistics, and time frames for the control of a well blowout.

18 AAC § 75.445(d)(2).

In addition to weakening amendments to the regulations governing well blowout mentioned above, ADEC also has weakened contingency planning oversight in other ways. For example, under its recently amended regulations, there is now a cap on the response planning standard for well blowouts. The new regulations provide that the response planning standard for a well blowout will be based on a flow rate of 5,500 barrels per day for a maximum of 15 days regardless of how many days it is expected to take to stop the discharge.[34] Over the years, however, both ADEC and plan holders have acknowledged that it could take up to 30 days to stop a well blowout if well capping is used, and that it could take up to 60 days to stop a well blowout if it is necessary to drill a relief well.[35] Thus, ADEC is allowing the oil industry to get away with having the resources to respond to a spill of, at most, 82,500 barrels (5,500 barrels/day x 15 days) when it is widely known that a blowout could allow the release of oil for 60 days, meaning much more than 82,500 barrels would be discharged into the environment.

ADEC's amended regulations also now allow contingency plan holders to plan for the "voluntary ignition" of a well that has blown out.[36] If certain data is provided to ADEC in that regard, the regulation directs ADEC to adjust the response planning standard downward, i.e., lower the volume of oil that a holder must be ready to, and plan to, contain and cleanup.[37] In effect, based on the untested assumption that less oil would reach the water once a "voluntary" ignition of the blown out well occurs, this downward adjustment allows the plan holder to keep less personnel and equipment at the ready.

As another example of changes that significantly weaken planning oversight, under ADEC's amended regulations multiple facilities now may be grouped under a single contingency plan. While this grouped approach may make it cheaper for operators willing to jointly develop a contingency plan, it may also mean that the special features of facilities or sensitive receiving environments near the facilities will not be adequately analyzed or protected.

Exacerbating the problems created by the amended regulations, ADEC has misinterpreted its authority to attach reasonable terms and conditions to a contingency plan approval. ADEC is allowed by statute and regulation to impose conditions necessary to ensure that the applicant for a contingency plan has access to the resources promised in the plan in order to respond to a spill.[38] ADEC applies the law, however, so

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[34] *See* 18 AAC § 75.434(b). Note that ASRC Energy Services indicated that it would take up to *sixty* days to drill a relief well. *See* ASRC C-Plan, ADEC Plan No. 044-CP-5105, at 1-1, 1.6-4, 1.6-25 (approved Dec. 16, 2004).

[35] *See, e.g.*, ASRC C-Plan, ADEC Plan No. 044-CP-5105, at 1-1, 1.6-4, 1.6-25 (approved Dec. 16, 2004).

[36] *See* 18 AAC § 75.434(e).

[37] *See id.* Indeed, under the amended regulations ADEC may now only adjust the response planning standard downward, not upward, even if it receives information that the planning standard established in the plan is too low.

[38] *See* 18 AAC § 75.460(a); AS 46.40.030(e).

as to create an approval loophole for deficient plans. ADEC claims that it has authority to approve otherwise deficient plans as long as it imposes terms and conditions that the holder must comply with at later date. These terms and conditions might require the plan holder to submit documents or take certain kinds of action. Since the submission of documents or other actions a plan holder takes would occur *after* ADEC approves the contingency plan, there is no way for the public to know if they are sufficient. After ADEC's plan approval occurs, there is no public review process. Thus, the public can't comment on plan provisions it hasn't seen and which will supposedly be implemented later, after the operator may have begun operations.[39]

EXAMPLE

A recent example shows how lax contingency plan oversight has become. In late 2004, ADEC approved a contingency plan that ASRC Energy Services submitted for the so-called Nearshore Stratigraphic Test Well in Eastern Beaufort Sea waters offshore of the Arctic National Wildlife Refuge.[40] The contingency plan spends one page discussing well-capping[41] and drilling a relief well (which would take "50 to 60 days") as the strategy for responding to a well blowout.[42] The contingency plan ostensibly relies upon the services of GSM, Inc. to provide control services in the event of a well blowout, and the contingency plan states that details of a well capping plan are in a "separate proprietary "separate proprietary document."[43] Conservation organizations submitted a public records act request to ADE in order to review this "separate proprietary document." In response, ADEC released a document entitled "Teaming Agreement," signed by representatives of GSM, Inc. and ASRC Energy Services. ASRC's cover letter referred to this as "*the agreement* with the well control specialist."[44] And, ADEC's cover letter releasing the document to conservation organizations referred to it as "*the contract* between GSM, Inc., and ASRC Energy Services, as you requested."[45]

Contrary to ASRC's and ADEC's claim, however, the Teaming Agreement is not a contract. In fact, the Teaming Agreement expressly states that it is *not* contract:

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[39] *See* 18 AAC § 75.455 (setting out the procedures for taking public comment on a proposed a contingency plan).

[40] Conservation organizations lengthy criticism of ADEC's approval of the ASRC Energy Services' contingency plan is available on Trustees for Alaska's website at www.trustees.org.

[41] A summary description of well capping, and the significant safety and mechanical problems faced during a blowout, can be found at the John Wright Co. website, http://www.jwco.com/technical-litterature/p10.htm (last visited Dec. 20, 2005).

[42] ASRC Energy Services, *Oil Discharge Prevention and Contingency Plan for Nearshore Stratigraphic Test Well Eastern Beaufort Sea, Alaska* (April 2004), at 1.6.4.

[43] *Id.*

[44] ASRC Cover Letter (July 26, 2004).

[45] ADEC Cover Letter (Oct. 25, 2004).

> *This Agreement is nonbinding* and is intended solely as a summary of the terms currently proposed by the Parties. The Parties further acknowledge and agree that they neither intend to enter, nor have they entered into any agreement to negotiate a definitive agreement pursuant to this document, and that either Party may, at any time prior to execution of such definitive agreement, propose different terms from those summarized here, or unilaterally, and at either Party's absolute discretion, terminate all negotiations without any liability whatsoever to the other Party.[46]

The Teaming Agreement also is devoid of any reference to a specific project. It does not mention the Nearshore Stratigraphic Test Well, exploratory drilling activities in the Beaufort Sea, or any well blowout control or other spill response obligations that GSM, Inc. might undertake. Nonetheless, ADEC approved the contingency plan. The public had no opportunity to review the Teaming Agreement and therefore no opportunity to comment on its obvious deficiencies.[47]

ADEC HAS FORGOTTEN WHAT LED TO THE T/V EXXON VALDEZ SPILL.

In total, the regulatory amendments and misinterpretations of law ADEC has come up with represent the same kind of agency backsliding on standards and coziness with the regulated industry that led to the Santa Barbara, the T/V Exxon Valdez, and other major oil spills. It is thus worth repeating, as warnings, two of the key findings that the Alaska Oil Spill Commission made:

> IV. In government as well as industry, enforcement zeal declined, alertness sagged and complacency took root in the years preceding the Exxon Valdez disaster. Prevention was neglected.
>
> * * *
>
> VII. Privatization and self-regulation in oil transportation contributed to the complacency and neglect that helped cause the wreck of the Exxon Valdez.[48]

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[46] Teaming Agreement, at 1 (emphasis added)(document on file at Trustees for Alaska).

[47] ADEC did require ASRC to submit a copy of the "contract" between ASRC and the well-control specialist to ADEC for its files at least 30 days before setting down its drilling rig each drilling season. *See* ADEC Final Approval (Dec. 16, 2004).

[48] State of Alaska, *Alaska Oil Spill Commission, Spill – The Wreck of the Exxon Valdez – Implications for the Safe Transportation of Oil – Executive Summary*, (January 1990), at 1.