North Slope Borough

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Edward S. Itta, Mayor

September 14, 2011

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

Re: Notice of Inquiry by the State of Alaska, Alaska Oil and Gas Conservation Commission, Changes or Additions Needed to AOGCC Regulations Governing Drilling, Rig Workover and Well Control in Offshore and Ultra-extended Reach Wells in the State of Alaska, Docket OTH-10-16

Dear Commissioner Seamount:

The North Slope Borough (NSB) appreciates the opportunity to submit comments in response to the Alaska Oil and Gas Conservation Commission (AOGCC) Notice of Inquiry regarding changes or additions needed to regulations governing drilling, rig workover and well control in offshore and ultra-extended reach wells in the State of Alaska, Docket OTH-10-16.

NSB commends AOGCC for initiating this review of regulatory powers in light of lessons learned from the tragic 2010 *Deepwater Horizon* blowout. NSB fully supports AOGCC's efforts to incorporate current best technologies and practices to improve drilling, rig workover and well control regulations for offshore and ultra-extended reach wells[1] in Alaska. Because the majority of our recommendations are not limited to offshore and ultra-extended reach wells,[2] but are appropriate to all drilling operations in Alaska, we recommend that AOGCC consider

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[1] AOGCC's regulations should include a definition for what constitutes an "ultra-extended reach" well.

[2] Onshore wells along the coastline have the potential to spill oil into the sea and pose similar risks to coastal resources including subsistence resources as offshore drilling. Additionally, onshore wells located near major river systems or water bodies have a potential to impact freshwater and seawater resources.

promulgating regulatory changes for both onshore and offshore addressing the issues identified in these comments.

NSB concurs with AOGCC that it was appropriate to defer hearings on regulatory reform until September 2011 to allow time for two federal investigative reports regarding the *Deepwater Horizon* – one report from the Bureau of Ocean Energy Management, Regulation and Enforcement and the United States Coast Guard (BOEMRE USCG Joint Investigation Team Report), and a second from the National Academy of Engineering and National Research Council (NAE/NRC Report).

The BOEMRE USCG Joint Investigation Team Report was deferred twice in 2011. The final report was released today, September 14, 2011, the day comments for this docket are due to AOGCC.[3] We were not able to review BOEMRE USCG report before developing our comments, but certainly will be examining the report closely.

The NAE/NRC report is scheduled to be released in 2011.[4] This report, prepared at the request of the Department of the Interior (DOI), will detail the probable causes of the *Macondo* well blowout, and *Deepwater Horizon* explosion, fire and oil spill. The purpose of the examination is to identify specific measures to prevent similar harm in the future. The NAE/NRC committee plans to identify and recommend best available technology, industry best practices, best available standards, and other measures in use around the world in deepwater exploratory drilling and well completion.

AOGCC should make every effort to include information from these final reports in this rulemaking process. And AOGCC should explain in its regulatory decision document how the recommendations from both of these reports were addressed.

Because we were not able to review the federal government's final investigative reports of the *Deepwater Horizon* blowout, we offer these recommendations as an interim, initial list. NSB expects AOGCC's regulatory revision process to involve substantial technical review, study and assessment. NSB offers continued assistance and expertise on improving these regulations, and requests the opportunity to send NSB representatives to workshops and technical review sessions related to this docket. We are committed to supporting AOGCC in its goal to improve Alaska's drilling regulations.

Please find below our initial set of recommendations.

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[3]BOEMRE USCG Joint Investigation Team website, http://www.deepwaterinvestigation.com/go/site/3043 (last visited September 14, 2011).

[4]National Academy of Engineering/National Research Council (NAE/NRC) committee website, http://www.nae.edu/Activities/Projects/deepwater-horizon-analysis.aspx (last visited September 13, 2011) ("The final report, initially due in June 2011, will not be completed until later in the summer").

1. **Drilling Rig Condition.** Drilling rig condition and suitability for operations in the arctic environment are fundamental to safe arctic drilling. Historically, only arctic-grade drilling rigs have been used. Recently companies have proposed use of jack-up platforms, temperate water drill ships, and other drilling and workover structures that were not built to arctic specifications or were partially modified to operate in limited ice conditions.

   AOGCC should adopt new regulations or amend existing regulations to ensure drilling rigs are in good condition and suitable for operation in the Arctic. AOGCC should require inspections of drilling rigs by an independent third party qualified to audit arctic drilling rigs. Prior to approval of any permit to drill application, the auditor should issue a report directly to AOGCC certifying that the drilling rig meets all regulatory requirements and is capable of safely operating in arctic conditions. The report should examine conditions the rig may encounter during the planned drilling period, as well as during any unplanned well-control operations that may require the rig to remain at the drillsite. The report should also verify that the rig has not been compromised or damaged from previous service. And, the audit should take place with adequate time for an operator to make appropriate changes or improvements. AOGCC should establish criteria in the regulations for certifying drilling rig auditors, develop a review and approval process to certify those auditors, and maintain a list of certified auditors on its website. All drilling rigs operating in the Arctic should be designed, tested and audited to ensure they are appropriate for the arctic operating conditions expected, including conditions anticipated during the period required to drill a relief well.

2. **Blowout Flow Rate.** AOGCC currently provides worst-case well blowout flow rate technical support and analysis to the Alaska Department of Environmental Conservation (ADEC) for purposes of determining a worst-case well blowout Response Planning Standard (RPS) as required by 18 A.A.C. Chapter 75. NSB is concerned that the RPS method and minimum RPS thresholds used do not accurately represent true worst-case scenarios. The exploration well blowout rate of 5,500 barrels oil per day (bopd) is not a worst-case rate for all wells in Alaska, and in many cases under-predicts the worst-case well blowout flow rates for arctic wells. And, the production well blowout rate also under-predicts the blowout flow rate because it is based on an average oil production rate, assuming there is back-pressure on the wellhead; this would not be the case in an unobstructed, open orifice well blowout (a worst case scenario).

   AOGCC should develop worst-case blowout rates for exploration wells based on its experience with offset wells and ensure that the rate is representative of a true worst-case scenario. And, AOGCC should adopt BOEMRE's method of computing a worst-case well discharge based on a fully unobstructed, open-orifice maximum well blowout. AOGCC's technical review and approval process and method of computation should be clearly explained in regulation. This recommendation would require coordinated regulatory revisions at 18 A.A.C. Chapter 75 to improve AOGCC's and ADEC's combined well blowout estimating methods.

3. **Arctic Well Capping and Containment System for an Offshore Subsea Well Blowout and Capping System for an Onshore Surface Well Blowout.** A subsea, arctic well capping system has not yet been built for Chukchi or Beaufort Sea offshore drilling operations. Shell is in the process of constructing a system; however, this system has not been tested, nor has BOEMRE or AOGCC set specific performance standards for its construction or operation. There is limited well capping equipment located on the North Slope for wells, onshore or offshore, with surface BOPs; however, most well capping plans rely on part or all of the required capping equipment being transported in from Texas or overseas, delaying response time.

   AOGCC should require operators to have an appropriate arctic well capping and containment system or capping system on contract. AOGCC should set specific construction and operating performance standards for this equipment. This system should be located in the Arctic, outfitted with necessary supplies and equipment, and staffed with trained and qualified personnel capable of initiating a well capping operation within 24 hours. The arctic well capping and containment system or capping system should be built to arctic engineering specifications and physically tested in the arctic conditions in which the applicant plans to operate. The amount of hydrocarbon development on the North Slope, and the unique nature of arctic well capping operations warrant a full set of well capping equipment for surface BOPs and another for subsurface BOPs, to provide immediate well control.

4. **Relief Well Rig Capability.** As observed during the 2010 *Macondo* well blowout, and the 2009 *Montara* well blowout, relief well rig capability provided a critical emergency and source control function. Despite the importance of relief well drilling rigs, drilling operators continue to submit applications that do not identify a second relief well drilling rig by name, demonstrate that the relief well rig is on contract, located in the Arctic, outfitted with necessary supplies and equipment to conduct relief well drilling operations, and staffed with trained and qualified personnel who are capable of initiating relief well operations within 24 hours. It will likely be even more difficult to find on short notice a relief well rig capable of controlling a blowout from an ultra-extended reach drilling operation.

   AOGCC should adopt new regulations or amend existing regulations to specify that before a permit-to-drill application is approved, the operator must identify a second relief well drilling rig by name, demonstrate that the relief well rig is on contract, located in the Arctic, outfitted with necessary supplies and equipment to conduct relief well drilling operations, and staffed with trained and qualified personnel who are capable of initiating relief well operations within 24 hours. The second relief well rig should be at least of equivalent capability as the primary drilling rig.

5. **Relief Well Rig Availability.** The size of a well blowout and the amount of oil spilled into the environment will be a function of the time required to transport a relief well rig to the drilling site and the time required to drill the relief well. To

expedite relief well operations and reduce the spill size the relief well rig must be located close-by and immediately available.

To ensure that the relief well rig is immediately available and capable of meeting the 24-hour response period, the relief well drilling rig must be located near the primary drilling rig to ensure a 24-hour transit time, including time to stop drilling and suspend the well if it is drilling. Additionally, relief well rig operations should be timed to ensure that it is not drilling through a higher risk hydrocarbon zone at the same time that the primary drilling rig is drilling through a hydrocarbon zone, AOGCC regulations should require the relief well rig to postpone or suspend drilling operations until the primary drilling rig has confirmed it has safely accessed the zone of interest."[5]

6. **Relief Well Rig Pre-Planning.** Planning for a relief well prior to drilling, rather than waiting until an emergency situation, will expedite relief well design, permitting and planning. While additional permitting and review may be required prior to drilling the actual relief well, pre-planning will expedite the process especially for offshore wells.

   AOGCC should require operators to prepare a relief well plan prior to drilling, and AOGCC should review and approve this preliminary plan. The following recommendations reflect standards met by operators drilling offshore wells in Greenland:

   - Two alternate relief well locations should be fully identified, permitted and surveyed for shallow gas prior to operations commencing on the primary well site.

   - Relief well sites should be evaluated to ensure the current profiles, benthic character, seabed topography and rig access plans are fully suitable for relief well operations.

   - Pre-planned relief well design trajectories should be approved by AOGCC based on various well blowout scenarios; final well design trajectories should be approved prior to actual relief well drilling.

   - A well control drill should be conducted ahead of the drilling season to test an operator's relief well plan, and well-capping strategy.

[5]This oil spill prevention measure is currently being used for arctic offshore drilling operations in Greenland. Cairn Energy Plc, Oil Spill Contingency Plan. 38-49 (2011).

7. **Blowout Preventer (BOP) Age and Condition.**[6] BOPs are critical well control devices. BOP age and condition are critical factors in performance and reliability. Old BOP systems may have served their useful lives, and should be taken out of service and replaced with new BOP systems. NSB commends AOGCC for its on-site BOP testing program, and we believe that this should continue in the future. Additionally, independent auditors could provide an additional audit level on this critical safety equipment.

   AOGCC should adopt new regulations or amend existing regulations to ensure that BOPs are in good condition. Regulations should specify that no BOP more than 20 years old may be used. The condition of the BOP should be examined by an independent third party qualified to audit arctic BOP systems. Prior to approval of any permit to drill application, the auditor should issue a report directly to AOGCC certifying that the BOP meets all regulatory requirements and is able to provide well control capability for the planned operations. In the report, the auditor should verify at a minimum that: the BOP type and condition is compatible with the specific well design and equipment on the rig; the BOP stack has not been compromised or damaged from previous service; and the BOP will operate in the conditions in which it is planned to be used. The audit itself should take place with adequate time for an operator to make appropriate changes or improvements to its BOP systems. AOGCC should establish regulatory criteria for certifying BOP auditors, develop a review and approval process for those experts, and maintain a list of certified experts on its website.

8. **BOP Activation Reporting.** BOPs should be the last line of defense in well control. Activation of the BOP system is an indication that improvements are needed in the well control measures leading up to BOP activation. NSB commends AOGCC for taking prompt action to address the increased number of BOP activations in 2010, where blowout preventers had been activated 12 times[7] between January and June 2010.[8] AOGCC should continue to prioritize tracking of BOP activations.

   AOGCC could establish a formal regulatory requirement that operators immediately report each BOP activation and release these reports to the public. Reporting the BOP activation frequency and operator analyses of what prevention improvements could be made on future drilling and well work would provide a system of continuous evaluation and improvement.

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[6] *See* 30 C.F.R. § 250.416(f) (requiring independent third party verification to ensure: subsea BOPs are compatible with the specific well design and equipment on the rig, the BOP stack has not been compromised or damaged from previous service, and the BOP will operate in the conditions it will be used).

[7] Ten of the cases involved rigs working for BP and the other two were rigs working for CPAI and Pioneer.

[8] Wesley Loy, *BOP Use up on Slope: Rig Crews Trip Blowout Preventers 12 times in 2010, Regulators Question BP*, Petroleum News (June 27, 2010), *available at* http://www.petroleumnews.com/pntruncate/655937957.shtml.

9. **BOP Testing Frequency.** BOP testing is one method of examining capacity to control a well blowout. Currently BOP testing is conducted at least once every 14 days. Some operators have increased BOP testing frequency to 7 days, which we agree is a prudent prevention measure. AOGCC should require an increase in BOP testing frequency from 14 days to 7 days

   If repairs are needed on the BOP after a failed test, there are currently no performance standards or criteria for review and certification of the BOP before use. A failed BOP test should trigger BOP repair or replacement. Repaired BOPs should undergo third-party review and certification before use. And, the well should be secured with at least two additional independent well barriers while BOP repair and replacement is underway.

10. **BOP Control Systems.** In response to the *Macondo* well blowout, BOEMRE issued improved drilling regulations at 30 C.F.R. Part 250, and the National Commission on the BP *Deepwater Horizon* Oil Spill published a number of recommendations.[9] Consistent with the approach taken by BOEMRE and the National Commission, AOGCC should establish additional requirements for BOP control systems.

    AOGCC should require installation of physical barriers on BOP control panels to prevent accidental disconnect functions. BOP control panel systems should be clearly labeled. Personnel should be trained and qualified to operate the BOP, including the prevention of accidents and unplanned disconnects of the system. BOPs should be equipped with sensors and/or other tools to obtain accurate diagnostic information regarding pressures and the position of the BOP rams.

11. **BOP Blind-Shear Rams.** Consistent with BOEMRE's improved drilling regulations at 30 C.F.R. Part 250, AOGCC should adopt new regulations or amend existing regulations to require blind-shear rams to be capable of shearing any drill pipe (including jointed segments) in the hole under maximum anticipated surface pressures, plus an additional safety margin.[10] Blind-shear rams should be tested prior to drilling; this test should be witnessed by AOGCC. Redundant blind shear rams should be required on all BOPs.[11]

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[9] *See* 30 C.F.R. § 250.442 (requiring operational and physical barriers on BOP control panels to prevent accidental disconnect functions; clear labeling of BOP control panel systems; a management system for operating the BOP, including the prevention of accidents or unplanned disconnects of the system; and minimum requirements for personnel authorized to operate critical BOP equipment); National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation D4 (January 11, 2011) (recommending BOPs should be equipped with sensors or other tools to obtain accurate diagnostic information regarding pressures and the position of the BOP rams).

[10] *See* 30 C.F.R. § 250.442 (requiring blind-shear rams to be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures).

[11] BOEMRE made an important first step requiring independent third party verification of blind-shear ram capability in its October 2010 Drilling Safety Regulation Revisions at 30 C.F.R. § 250.416(f). However, the agency deferred

12. **BOP Redundancy.** Redundant BOPs provide an additional level of emergency control capability, which is especially important for remote offshore drilling operations where transportation of a back-up BOP could result in significant delays in emergency well control operations. Some operators have proposed the use of redundant BOPs as an added oil spill prevention measure; we agree. AOGCC should require redundant BOP systems for all floating offshore drilling rigs that use subsea BOPs.

13. **Remotely Operated Vehicle (ROV) Capability.** Arctic BOPs systems, installed in Mud Line Cellars (MLC), which protect the BOP from ice, create unique challenges for ROV access. AOGCC should require subsea BOPs be designed to facilitate immediate, direct ROV access to BOP controls. Because arctic subsea BOPs are located in MLCs, the hot stab access point for ROV connection should be located on top of the BOP and unobstructed. A redundant ROV hot stab panel should be on a seafloor sled located a safe distance away from the well, as a means to operate the BOP if the ROV hot stab panel on the BOP is inaccessible. Redundant ROV and diver capability on a support vessel, along with launch and recovery systems for each, should also be required.

14. **Alternative Well Kill System (AWKS).** Best Available and Safest Technology (BAST) should be used for arctic BOP systems. Depending on the timing of AOGCC's rulemaking, Chevron may have an improved arctic subsea well blowout system, AWKS, built and commercially available.[12] AOGCC should consider adding BAST requirements for subsea BOP systems, including the possibility of making AWKS mandatory for offshore drilling, provided that it is commercially available and provided that a rigorous peer-reviewed engineering evaluation of this system verifies that it is an improvement for arctic subsea BOP systems.

15. **Two Barrier Well Control Systems.** After the 2010 *Macondo* well blowout and 2009 *Montara* well blowout, BOEMRE and a number of states re-examined and clarified their well barrier regulations to clearly require a minimum of two barriers – a primary and backup – be installed to control wells at all times.[13]

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the requirement to install redundant blind-shear rams in each offshore BOP to a later rulemaking process. BOEMRE, Increased Safety Measures for Energy Development on the Outer Continental Shelf, 75 Fed. Reg. 63,346, 63,353 (Oct. 14, 2010). Redundant blind-shear rams should be required in both state and federal regulations.

[12]Chevron Canada Limited, Canadian National Energy Board Arctic Offshore Drilling Review AODR Submission Part 1: Briefing Document, 25 (Apr. 2011) ("The AWKS Safety Package is an add-on to the bottom of the existing BOP stack. Such an add-on could be incorporated without the need to interfere with the design and operation of the main BOP stack and, as such, would provide 100% redundancy in the case of an emergency. Further redundancy can be incorporated through the use of 2 AWKS shear and seal rams thus providing 100% back-up in shearing and sealing capability over a broad range of drilling tubulars and casing. Acoustic control could be considered for such a safety system thus potentially allowing the BOP to be operated independently from a drilling support vessel in the event the rig itself is disabled").

[13]*See* 30 C.F.R. § 250.420 (clarifying the minimum number of well control barriers).

AOGCC regulations should take a similar approach and unambiguously require that at least two independent well control barriers are in place at all times. Both barriers should be routinely tested and at least one barrier should be mechanical.

16. **Minimum Drilling Stock Levels.** Well control operations require sufficient on-site materials. Remote arctic operations, and severe weather can delay or halt supply lines. Therefore, for arctic operations, on-site drilling stock levels establish the degree of well control readiness.

    AOGCC should require operators to establish minimum drilling stock levels for essential well control materials and require agency review of the minimum stock levels planned as part of the permit to drill. These materials, at a minimum, should include: drilling mud including weighting material and loss circulation additives; cement and other well plugging material; fuel sufficient for several days of operation (in case of inclement weather delaying fuel transfers), and backup power systems.

17. **Well Control Experts.** Most operators indicate they have contracted with a well control expert, and that the expert can be flown in (usually from Texas) to assist in a well blowout. Transiting from the Lower 48 puts the expert out of touch for almost a day. And, companies are not required to show evidence of an actual contract, nor are there specific performance standards to ensure that the well control expert is trained, qualified and experience in arctic well control operations. This is important because arctic well control operations have unique challenges.

    Operators should be required to have a signed contract with a certified expert well control company that has demonstrated to AOGCC's satisfaction it has sufficient arctic well control experience, qualifications, trained personnel and equipment. Evidence of this contract should be submitted in the permit to drill application. AOGCC should establish criteria in regulation for certifying arctic well control experts, develop a review and approval process to certify those experts, and maintain a list of certified experts on its website. AOGCC should require that the certified well control experts be present on the rig during drilling of all offshore and ultra-extended reach wells to provide additional expert support to the operator.[14]

18. **Cement Evaluation Tools.** Consistent with NAE/NRC recommendations,[15] AOGCC should adopt new regulations or amend existing regulations to require that all cement be evaluated using a cement evaluation tool (CET), cement bond log (CBL), or equivalent well logging tool to examine cement quality. AOGCC should require operators to run cement evaluation tools and submit well logging data to AOGCC as

[14]At a minimum, AOGCC should require well control experts be onboard while drilling through hydrocarbon zones on production wells and during all drilling operations for exploration wells.

[15] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending improved cement evaluation).

evidence of a successful cement job.[16] Cement quality should be verified by AOGCC. If the cement evaluation tools show cement integrity problems, AOGCC regulations should require immediate remedial cementing actions. The requirement for cement evaluation logging should be mandatory, at a minimum, for all offshore wells, wells along the coastline that could spill oil to the sea and ultra-extended reach wells. Additionally AOGCC should establish requirements for when cement logging would be required for onshore wells.

19. **Cementing Techniques and Quality Control/Quality Assurance Procedures.** Cement is a critical structural component of building a safe and environmentally sound well. Poor cementing has been cited as a problem for loss of well control historically, including in the *Macondo* blowout.[17] Consistent with NAE/NRC recommendations,[18] cementing techniques and quality control/quality assurance procedures should be updated to optimize: cement selection and testing prior to the cement job;[19] cement placement, including initial well construction and well plugging operations; and cement quality control and quality assurance protocol. Regulations should provide specific quantitative standards for cement compressive strength,[20] and

[16] Due to the incremental cost of running cement evaluation tools in offshore and complex wells such as extended-reach wells, some operators skip this test, relying only on cement displacement volumes and limited pressure testing to estimate cement placement success. This practice may be insufficient to verify cement integrity.

[17] David Izon, E.P. Danenberger, Melinda Mayes, Minerals Management Service, *Absence of fatalities in blowouts encouraging in MMS study of OCS incidents 1992-2006*, Drilling Contractor (July/August 2007) *available at* http://drillingcontractor.org/dcpi/dc-julyaug07/DC_July07_MMSBlowouts.pdf (concluding "during [1992-2006], the percentage of blowouts associated with cementing operations increased significantly from the previous period").

[18] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending improved cement techniques and quality control/quality assurance procedures).

[19] For example, Texas requires: "Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. *Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the commission prior to the cementing operation.* To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i) *For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.*" 6 T.A.C. Part 1 § 3.13(b) (2) (D) (emphasis added).

[20] 20 A.A.C. § 25.030 currently requires "sufficient compressive strength" but does not define in quantitative terms what constitutes sufficient cement compressive strength. For example, Texas specifically requires: "Surface casing strings must be allowed to stand under pressure until the cement has reached a *compressive strength of at least 500 psi* in the zone of critical cement before drilling plug or initiating a test. *The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.* ...In addition to the minimum compressive strength of the cement, *the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B.* The commission may require a better quality of cement

should establish minimum setting-time periods for cement before allowing continued drilling.[21]

20. Casing Centralizers. Consistent with NAE/NRC recommendations, [22] AOGCC should review and update its casing centralizer criteria to ensure casing is centralized in the drill hole prior to cementing in order to optimize cement placement. For example, 20 A.A.C. § 25.527 should include a technical standard for minimum centralizer placement such as API-10D.

21. Emergency Well Control Plan. While drilling operators typically have emergency well control plans, those plans are not currently subject to detailed AOGCC review and approval, nor are there specific performance criteria and standards for these plans in Alaska regulation. There would be merit in AOGCC establishing plan standards, and conducting a technical review of these plans to provide the public with the assurance that a quality plan is in place and that AOGCC is familiar with that plan.

A comprehensive written *Emergency Well Control Plan* should be required as part of the application for a permit to drill. The plan should cover the primary rig, well capping and containment equipment, secondary relief well rigs, and additional well barriers. AOGCC's approval of this plan should be subject to rigorous examination. In the event a well blowout occurs, this process will ensure that AOGCC is already familiar with the operator's response methods—expediting the well control and relief well drilling approvals needed during an emergency.

22. Source Control Plans. Consistent with recommendations of the National Commission on the BP *Deepwater Horizon* Oil Spill,[23] source control plans should be submitted for AOGCC review and approval as part of the permit-to-drill application.

23. Seasonal Drilling Duration. Arctic environmental conditions – including darkness, sea ice, and extreme cold – prevent exploratory drilling operations during significant portions of the year and present unique challenges for oil spill clean-up operations.

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mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area." 16 T.A.C. Part 1 §3.13(b)(2)(C) (emphasis added).

[21] Wait on Cement (WOC) time periods should be specified to ensure the cement has ample opportunity to firmly set to the required strength, prior to disturbance with continued drilling.

[22] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending casing centralizer requirements to maintain an adequate annulus for cementing between the casing and the formation rock).

[23] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation D2 (January 11, 2011) (source control plans should be required as part of both oil spill response plans and applications for permits to drill).

Routine drilling operations that extend to the very last day that it is safe to drill and clean up spilled oil do not allow time to respond to a well control event.

To ensure there is sufficient time left in the safe operating season to cap a blown out well, drill a relief well and clean up spilled oil, AOGCC should only permit operations that have a margin of safety built into their proposed plan of operations. The permissible drilling permit duration should be limited to the total period of time the drilling rig is capable of working in arctic conditions, minus the time required for oil spill cleanup and time required to cap and/or drill a relief well (whichever is longer).

24. **Ice Hazards.** Ice hazards – including, but not limited to strudel scour, ice gouging, ice break-off, shear zone and pressure ridging, ice override and pile up (including ivu events), and melting sea ice – increase the risk of an oil spill. Thus, all drilling and well work operations should be required to address the risks associated with ice hazards. Operations should be planned to avoid ice, and/or mitigate potential ice risks while operating in ice conditions.

25. **Floating Drilling Rig Arctic Ice Class.** Consistent with international standards, all floating offshore drilling rigs operating in arctic ice conditions, including primary and relief well rigs should meet Arctic Ice Class IV, Polar Class[24] or equivalent[25] standards. Floating offshore drilling units should not be used beyond the phase of initial exploration.

26. **Offshore Development Drilling (Post-Exploration).** Consistent with NSB Municipal Code requirements for offshore development, all offshore development drilling, after exploration drilling is complete, should be conducted from bottom founded structures or gravel islands unless another alternative is environmentally preferable, has fewer adverse impacts on subsistence hunting and is safer. The construction of new platforms and islands should be avoided to the maximum extent practicable through the use of directional drilling from shore or from existing islands.

27. **Icebreaking Capability of Drilling Rig Support Vessels.** Consistent with BOEMRE requirements at 30 C.F.R. Part 250, floating offshore drilling rigs, including primary and relief well drilling rigs, should be supported by the minimum number of ice breakers required for safe operation, as determined by USCG. Additional redundant icebreaker capability should be factored into regulatory requirements in case of loss or damage to one or more ice breakers.

28. **Mud Line Cellars.** Consistent with BOEMRE requirements at 30 C.F.R. Part 250, AOGCC should require that mud line cellars (MLCs) be constructed to protect subsea

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[24]International Association of Classification Societies, Requirements Concerning Polar Class (2001).

[25]International Maritime Organization, Guidelines for Ships Operating in Arctic Ice-Covered Waters (2002).

BOPs from ice damage.

29. **Drilling Hazard Identification or "Safety Case."** Consistent with NAE/NRC[26] and the National Commission on the BP *Deepwater Horizon* Oil Spill[27] recommendations, AOGCC should require operators file a drilling or workover hazard identification (HAZID) analysis or "safety case," along with a Hazard Mitigation Strategies Plan. These materials should be submitted as part of the drilling or workover permit application.

30. **Safety and Environmental Management Systems.**[28] Consistent with the National Commission on the BP *Deepwater Horizon* Oil Spill recommendations, AOGCC should expand safety and environmental management system requirements for drilling to include third party audits at three to five year intervals and certification.

31. **Use of Long-string Production Casing Design.** Consistent with the NAE/NRC recommendations, AOGCC should establish criteria for the use of long-string production casing designs.[29] Long-string production casing can increase well construction risks and those risks must be carefully assessed against potential consequences.

32. **Casing Grade.** Consistent with good engineering practices (GEPs), AOGCC should require operators to design and install casing that is able to withstand the effects of corrosion and erosion. As wellbore conditions dictate, AOGCC should require the use of coated piping, higher grade piping, or thicker walled piping with a higher corrosion allowance.

33. **Recommended Good Engineering Practices and Standards.** Consistent with GEPs, as well as AOGCC's typical procedure of updating engineering practices and standards during regulatory revisions, 20 A.A.C. § 25.527 should be updated to

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[26] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending drilling hazard identification to anticipate and manage inherent risks, uncertainties, and dangers associated with drilling operations).

[27] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendations A2 and A3 (January 11, 2011) (recommending risk-based drilling assessments be completed prior to drilling, similar to the "Safety Case" approach used in the North Sea; and recommending that regulators "require operators to develop a comprehensive 'safety case' as part of their exploration and production plans—initially for ultra-deepwater (more than 5,000 feet) areas, areas with complex geology, *and any other frontier or high risk areas—such as the Arctic*" (emphasis added)).

[28] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation A3 (January 11, 2011) (recommending that the safety and environmental system requirements for drilling be expanded to include third-party audits at three to five year intervals and certification).

[29] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending well construction design for complex wells (e.g. long-string production casing design should not be used in deep, high pressure wells across multiple hydrocarbon zones)).

include the most current engineering standards, supplemented with additional materials created since this list was last codified in 1999.

34. **Reserve Pits and Drilling Waste Handling.** Because grind and inject technology is proven best practice for arctic drilling operations, AOGCC should revise 20 A.A.C. § 25.047 to disallow reserve pits for arctic wells. Drilling waste should be routed to tanks, or vessels if offshore, and then transported or piped to an approved subsurface disposal well or waste handling facility. No drilling muds or cuttings should be allowed to be disposed of offshore.

35. **Improved Prescriptive Safety and Pollution Prevention Standards.** Consistent with the National Commission on the BP *Deepwater Horizon* Oil Spill recommendations,[30] AOGCC should complete a peer-reviewed study that examines additional prescriptive safety and pollution prevention standards. The study should be conducted in consultation with international regulatory peers. The end goal should be to draft regulations that are comparable with or more rigorous than the leasing terms and requirements in peer oil-producing nations.

36. **Near Miss and Lessons Learned Reporting.** Consistent with the NAE/NRC and the National Commission on the BP *Deepwater Horizon* Oil Spill recommendations,[31] AOGCC should develop more detailed requirements for incident reporting. AOGCC should also develop a system to collect data on offshore incidents and near misses to facilitate the State's developing a stronger risk assessment and analysis program.

37. Unplanned incidents and near misses are valuable tools in advancing state-of-the-art technologies and regulations.

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[30] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation A1 (January 11, 2011) (recommending prescriptive safety and pollution prevention standards be developed and selected in consultation with international regulatory peers, and that standards be at least as rigorous as the leasing terms and regulatory requirements in peer oil-producing nations); *Id* at Recommendation A3(recommending that regulators: "Engage a competent, independent engineering consultant to review existing regulations for adequacy and 'fit for purpose' as a first step toward benchmarking US regulations against the highest international standards. Following this review, develop and implement regulations for safety and environmental protection that are at least as rigorous as the regulations in peer oil-producing nations.")

[31] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending improved lessons learned and near-miss analysis); National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation A3 (January 11, 2011) (recommending more detailed requirements for incident reporting and data concerning offshore incidents and near misses to allow for better tracking of incidents and stronger risk assessments and analysis; and recommending that: "such reporting should be publically available and should apply to all offshore activities, including incidents relating to helicopters and supply vessels, regardless of whether these incidents occur on or at the actual drilling rigs or production facilities").

38. **Whistleblower Protections.** Consistent with the NAE/NRC and the National Commission on the BP *Deepwater Horizon* Oil Spill recommendations,[32] AOGCC should develop improved whistleblower protections for personnel that notify authorities about lapses in drilling and workover operation safety. Again, information collected from drill site mishaps can be used constructively in efforts to improve regulations and standard protocols.

39. **Application Fees.** AOGCC should increase permit application fees that can be used to cover the cost of hiring additional experienced and qualified engineers and third-party experts to review these permit applications and provide advice on drilling projects.

40. **Bonds.** Operators currently only need to cover the cost of well abandonment and location clearance, and the bond amount is insufficient to address the potential risk and consequences of drilling operations.[33] Therefore, AOGCC should increase the bond amount required of operators to correspond to the potential risk and consequences of drilling operations under 20 A.A.C. § 25.025.

41. **Drilling and Workover Personnel Training and Qualifications.** Consistent with NAE/NRC recommendations, AOGCC should establish in regulation updated drilling and workover personnel training and qualifications, including associated support contractors such as cementing contractors, well stimulation contractors, etc.[34] AOGCC regulations should summarize such requirements in a list, by job type, of the mandatory training, qualifications, certifications and years of experience required to hold that position, along with the training frequency. The operator should be required to maintain a database of its personnel training, and either track its contractors' training or require the contractors do so, such that these records are readily available to AOGCC for audit.

42. **Operator Qualifications.** Because of the unique operating conditions, arctic drilling and well control operations require unique expertise. Therefore, drilling contractors and operators should be required to meet a minimum set of operator qualifications for drilling in the Arctic. This qualification process should include an AOGCC examination of the applicant's previous experience in arctic hydrocarbon exploration and exploitation, previous experience from operations in areas with similar physical conditions, health, safety and environment (HSE) systems, and a review of the

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[32] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation A3 (January 11, 2011) (recommending improved whistleblower protections for personnel that notify authorities about lapses in drilling safety).

[33] The current bond amount of $100,000 per well or $200,000 for all of the operator's wells in the state, at 20 A.A.C. § 25.025, is insufficient.

[34] NAE/NRC, Interim Report on the Causes of the *Deepwater Horizon* Oil Rig Blowout (November 16, 2010) (recommending improved personnel training and qualification standards).

applicant's emergency response plans and previous experience in managing environmental emergency situations.

Again, we appreciate AOGCC's willingness to take a "hard look" at Alaska regulations in light of the many important lessons learned in the events that occurred in the Gulf of Mexico last year. The dividends gained by performing this task cannot be overstated—this diligence will ensure that Alaska is properly equipped to prevent a similar incident from occurring in the Arctic. On that note, I urge AOGCC to remember that during each step of this process we are translating what has been learned from experiences in the relatively temperate Gulf of Mexico to the harsh, unforgiving arctic environment. There are many unique limitations in the Arctic that must be considered and addressed during the decision-making process. Well control and other spill prevention technologies must address arctic-specific conditions and arctic-specific risks. We need to be cognizant that some technologies referenced as "*state-of-the-art*" are actually unproven and untested in arctic environments; therefore, we need to design and promulgate regulations cautiously and require testing in arctic conditions to verify technology efficacy before granting approved use. In regard to offshore drilling, I urge AOGCC to carefully consider and mitigate risks associated with: (1) the very short season between melting sea ice in July and the onset of winter conditions in October; and (2) the severe limitations of existing infrastructure in the Arctic from which to respond to a loss of well-control event.

A final topic that must be at the forefront when considering, designing and promulgating regulations is that arctic climatic change is occurring rapidly and has increased scientific uncertainty—this expanded uncertainty affects everything from predicting oil-spill trajectories to setting performance criteria for a blowout containment structure.

Please contact Dr. Ben Greene, in NSB's Department of Planning and Community Services, at (907) 852-0320 or ben.greene@north-slope.org if you have questions regarding our recommendations.

Sincerely,

Edward S. Itta

Edward S. Itta
Mayor

cc: Karla Kolash, NSB Mayor's Office
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Gordon Brower, Director, NSB Department of Planning and Community Services
Taqulik Hepa, Director, NSB Department of Wildlife Management
Ellen Sovalik, Director, NSB Department of Health and Social Services
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