

**I. BOEMRE Must Require Shell to Modify the Camden Bay Exploration Plan**

Shell's EP "must demonstrate" that the company has "planned" and is "prepared" to conduct the proposed activities in a manner that:

- (a) Conforms to the Outer Continental Shelf Lands Act as amended (Act), applicable implementing regulations, lease provisions and stipulations, and other Federal laws;
- (b) Is safe;
- (c) Conforms to sound conservation practices and protects the rights of the lessor;
- (d) Does not unreasonably interfere with other uses of the OCS, including those involved with national security or defense; and
- (e) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.<sup>1</sup>

Only if the information included in, and accompanying, the EP meets this standard should BOEMRE approve the EP; otherwise, the agency must either disapprove the EP or require Shell to modify the EP.<sup>2</sup> OCSLA regulations set out precisely what information must be included in, or accompany, the EP in order to "*demonstrate*" (not just assert or state) that Shell both has "planned" and is "prepared" to meet the criteria set out above (30 C.F.R. §250.202 criteria).<sup>3</sup> As outlined in our comments, we do not feel Shell has not met this standard, thus, BOEMRE must require modification of the EP.

**II. NSB Permit Required for Shell's Proposed Activities within NSB Jurisdiction**

Shell's EP fails to comply with 30 C.F.R. §250.213(a), which requires that "a listing, including filing or approval status, of the Federal, State, and *local* application approvals or permits you must obtain to conduct your proposed exploration activities" accompany the EP.<sup>4</sup> A NSB permit is required for a number of activities described in the EP, but Shell incorrectly

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<sup>1</sup> 30 C.F.R. § 250.202.

<sup>2</sup> 30 C.F.R. § 250.233(b).

<sup>3</sup> 30 C.F.R. §§ 250.211-.228.

<sup>4</sup> 30 C.F.R. §250.313(a)(emphasis added).

asserts that no local permits are needed<sup>5</sup> and has not yet applied to the NSB Planning Department for any. Shell must modify their EP and accompanying material to list the NSB permits required and must submit a permit application to the NSB Planning Department.

Title 19 of the North Slope Borough Municipal Code (NSBMC) requires NSB approval for certain of Shell's proposed activities. NSBMC requires approvals for "all uses and development."<sup>6</sup> A "use" includes a development or activity conducted from within, or function of a development."<sup>7</sup> Development is defined to specifically include: "construction, reconstruction, relocation, placement or alteration of a structure"; "change in the use or material increase in use of site, including any structure thereon"; "disturbance of the surface of the ground (including submerged ground) or sea ice"; "activities directly related to resource extractions"; and "tundra travel."<sup>8</sup> While, "pre-exploration activities" are specifically excluded from the definition of Development, exploration activities are not excluded.<sup>9</sup>

Pursuant to Title 19, other commercial operators have been required to obtain NSB permits for the types of activities Shell describes in the EP. For example, NSB Planning Department has issued permits to FEX for barging to Cape Simpson related to oil and gas exploration programs in NPR-A, to ACS for onshore and offshore spill response training, to BP for transportation between Northstar and West Dock, to Shell for safe harbor activities at Point Thompson, and to Exxon for barging activities in support of activities at Point Thompson.

Shell's EP describes onshore and nearshore service and support activities within the NSB's jurisdiction that qualify as uses and developments requiring a NSB permit. For example, Shell's EP states:

- "The exploration drilling operations will require the transfer of supplies between the Deadhorse/Westdock shorebase and Dutch Harbor with the *Kulluk* or *Discoverer*."<sup>10</sup>
- "The crew change and resupply helicopter and the fixed wing aircraft will be based in Deadhorse, Alaska, with the search-and-rescue helicopter stationed in Barrow, Alaska."<sup>11</sup>
- "Shell's shorebase for air transportation for the planned exploration drilling program will be located at the Deadhorse Airport."<sup>12</sup>

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<sup>5</sup> EP at 2-1.

<sup>6</sup> NSBMC § 19.50.010.

<sup>7</sup> NSBMC § 19.20.020 (emphasis added).

<sup>8</sup> NSBMC § 19.20.020.

<sup>9</sup> NSBMC § 19.20.020.

<sup>10</sup> EP at 1-1, 13-3.

<sup>11</sup> EP at 1-4.

<sup>12</sup> EP at 14-1.

- “Marine support for the planned exploration drilling program will be primarily from the BP Exploration (Alaska) Inc. operated West Dock.”<sup>13</sup>
- “Facilities will be consolidated in Deadhorse to support drilling, logistics, and oil spill response. Approximately 30 Shell personnel will be based in Deadhorse. Facilities include accommodations at the Prudhoe Bay Hotel and Service Area 10; office space at the existing Carlile building, rental of existing Carlile yard space for short term Oil Response and Drilling equipment staging, and the leasing of Era Helicopter's terminal building to support crew change operations across the different functions of Shell offshore drilling.”<sup>14</sup>
- “When drilling starts up again after the bowhead whaling hunt has concluded, additional resupply may be required from West Dock via the *Arctic Seal* (or similar vessel) via transfer to the *Harvey Spirit* (or similar vessel) to the drilling vessel. Each support vessel will require refueling 4-6 times during the drilling season depending on fuel consumption based on utilization.”<sup>15</sup>
- “During each drilling season, the West Dock Supply Vessel (*Arctic Seal* or similar vessel) may make several resupply runs to and from West Dock or other port.”<sup>16</sup>
- “Within coastal waters, the vessel traffic will occur between the prospects and existing industrial facilities at West Dock.”<sup>17</sup>
- Figure 13.e-1 shows Shell plans barge operations to transit from Camden Bay to West Dock in NSB waters.<sup>18</sup>

These activities will take place in Barrow, Deadhorse, West Dock, within NSB’s jurisdiction.<sup>19</sup>

If Shell has contracted with another operator to provide these support services, Shell must verify that the company has obtained the appropriate NSB permit and amended the permit to include the increased use resulting from Shell project activity. Regardless of who holds the permit, a NSB permit is required and must be listed in Table 2.a.1 of the EP.

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<sup>13</sup> EP at 14-1.

<sup>14</sup> EP at 14-1.

<sup>15</sup> EP at 13-3.

<sup>16</sup> EP at 13-8.

<sup>17</sup> EP at 15-24.

<sup>18</sup> EP at 13-12.

<sup>19</sup> NSBMC §1.08.010.

Table 2.a.1 on page 2-1 of the EP must be modified to reflect the need for a NSB permit, the text on page 2-1 must be modified to reflect the need for a local permit and Shell must submit the required permit application to the NSB Planning Department.

### **III. Reduced Water Discharges**

Shell has committed to not discharge drilling mud, cuttings with adhered mud, treated sanitary wastes, domestic wastes, bilge water and ballast water.<sup>20</sup> NSB appreciates Shell's reduction of water pollution discharges from the proposed wells.<sup>21</sup> Shell's approach to utilizing technically and economically feasible measures to reduce waste discharge streams is consistent with operators' legal and ethical responsibility to avoid and reduce adverse impacts to North Slope communities and the marine resources upon which they rely. Thus, NSB expects that Shell, and other OCS operators, will replicate and continuously improve upon this approach to water discharges in any future wells. NSB also requests that BOEMRE incorporate this reduced discharge plan into its regulatory approach.

Shell's baseline research for the Sivilluq and Torpedo well locations shows that Camden Bay has background values for trace metals as well as aliphatic and polycyclic aromatic hydrocarbons from previous drilling operations in this area.<sup>22</sup> Reduced water pollution discharges from Shell's proposed drilling operations will reduce the pollutant load on this already affected area, and prevent potential contamination of subsistence foods that NSB residents rely upon. Reduced water pollution discharges will also incrementally reduce the likelihood that the odor of these discharges might deflect subsistence species from feeding areas or migration routes.

On January 24, 2011, NSB provided comments to the Environmental Protection Agency (EPA) regarding Shell's Notice of Intent (NOI) to discharge under the National Pollutant Discharge Elimination Systems (NPDES) General Permit AKG-28-0000 for its proposed 2011 Sivulliq N Exploration Drilling Program in the Beaufort Sea. A copy of that letter is attached and incorporated into these comments for your reference (Attachment 1).

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<sup>20</sup> EP at 6-15.

<sup>21</sup> EP at 1-3, 2-2 ("By agreement with the local communities, during exploration drilling activities contemplated by the revised Camden Bay EP, Shell will not discharge selected waste streams during routine drilling operations, even though the waste streams are allowable discharges under the current United States (U.S.) Environmental Protection Agency (EPA) administered Arctic National Pollutant Discharge Elimination System (NPDES) General Permit (GP) AKG-28-0000. Shell will not discharge treated sanitary waste (black water), domestic waste (gray water), bilge water and ballast water at any time and drilling mud and cuttings with adhered drilling mud below the depth of the 20-in. conductor shoe. These wastes will be collected and stored on a deck barge and waste barge and transported and disposed of at an approved and licensed facility.").

<sup>22</sup> EP at 5-2 (Trefry and Trocine (2009)).

While Shell may voluntarily incorporate this measure in future wells, BOEMRE should also exercise its authority to incorporate the measure in Shell's permits and approvals. OCSLA regulations state that BOEMRE will regulate operations on a lease in a manner that will "prevent damage to or waste of any natural resource, property, or the environment."<sup>23</sup> Furthermore, BOEMRE can require Shell to restrict discharges to prevent unreasonable degradation to the marine environment.<sup>24</sup> Reduction of water pollution through use of technologically and economically feasible measures is consistent with BOEMRE's standards and authority.

While Shell's reduced discharge approach is a positive change from previous proposals, some clarification and additional information is needed to support conclusions. As noted in our comments to EPA. Additionally, in order to test assumptions made in Shell's application materials and to advance our understanding of wastewater discharges to Arctic marine waters, NSB requested that Shell conduct cooling water discharge temperature monitoring to accurately record the actual change from ambient conditions caused by the discharge of heated cooling water and that EPA set limitations on the type of chemical additives that can be used in both Shell's cooling systems and desalination units that would be discharged under this permit (please refer to our detailed analysis and recommendations in Attachment 1). NSB believes that Shell can readily address these recommendations and not significantly delay their application or EPA's work on this project.

#### **IV. Drilling Vessel Ice Class**

To evaluate the safety of Shell's operations in the Arctic, it is important to understand the conditions the drilling vessels can withstand. Shell's Camden Bay operations will extend to October 31<sup>st</sup>. A well blowout or other emergency may carry operations into November and possibly December. Shell reports that the Kulluk is rated to operate in 4' of ice and the Discoverer's hull has been "reinforced for ice resistance."<sup>25</sup> The EP states: "The *Kulluk* is designed to maintain its location in drilling mode in moving ice with thickness up to 4 ft (1.2 m) without the aid of any active ice management. With the aid of IMVs [Ice Management Vessels], the *Kulluk* would be able to withstand more severe ice conditions."<sup>26</sup> But the documents do not quantify the maximum ice conditions that the Kulluk can withstand with IMV support. Nor does the EP identify the maximum ice and winter storm conditions that might be experienced in December while drilling a relief well for a late season blowout, and whether the Kulluk can operate in those conditions.

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<sup>23</sup> 30 C.F.R. § 250.106(c).

<sup>24</sup> 30 C.F.R. § 250.300.

<sup>25</sup> EP at 1-151-15.

<sup>26</sup> EP, Appendix K, at 4.

Information regarding the *Discoverer* ice class is more limited. The EP notes that an “ice-belt” has been installed and DNV has determined that the ship now meets a DNV ICE-05 class,<sup>27</sup> meaning it may be capable of operating in up to 1.5’ of ice.<sup>28</sup> However, Shell does not identify the maximum ice and winter storm conditions that might be experienced in November or December while drilling a relief well for a late season blowout, or how these conditions compare with a maximum 1.5’ ice operating capability.

Shell states that the *Discoverer*’s “ice-belt” makes it structurally as safe as the Canmar drillships used in previous Beaufort Sea drilling operations in the 1990s, but provides no technical information to support this statement.<sup>29</sup> Canadian experts state though that the Canmar drillships were only built to operate in ice conditions up to a maximum of October 15<sup>th</sup>.<sup>30</sup> Canmar drillships’ limited ice class coupled with their station-keeping issues curtailed their effective drilling season to approximately 100 days (mid-July to mid-October). Thus, even if Shell had demonstrated that the *Discoverer*’s “ice-belt” made the vessel as safe as the Canmar drillships, that would not resolve concerns about the vessel operating in late season October - December ice conditions.

A number of regulatory provisions support BOEMRE’s requiring more specific information about the Kulluk and *Discoverer*. First, because the Kulluk and *Discoverer* are MODUs, Shell is required to have a contingency plan that addresses design and operating limitations of the drilling unit, to maintain safety and prevent damage to the environment including ice and storm events.<sup>31</sup> Second, 30 C.F.R. § 250.220 requires a Critical Operations

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<sup>27</sup> EP, Appendix K, at 5. (“The *Discoverer* is classed by DNV as a Mobile Offshore Drilling Unit (MODU) for worldwide service. It is a “1A1 Ship-Shaped Drilling Unit I” and is capable of performing drilling operations offshore Alaska. The *Discoverer* has been issued with a DNV Appendix to Class stating: “the structural strength and material quality of the ‘Ice Belt’ formed by the sponsons below the 8950mm A/B level, have been reviewed against the requirements for the DNV ICE-05 Additional Class Notation and found to meet those requirements (as contained in DNV Rules for Classification of Ships, Pt 5 Ch 1, July 2006) for a design temperature of -15 degrees C.”)

<sup>28</sup> [www.dnv.com](http://www.dnv.com)

<sup>29</sup> EP, Appendix K, at 5.

<sup>30</sup> Chevron Canada Limited, Canadian, National Energy Board Arctic Offshore Drilling Review AODR Submission Part 1: Briefing Document at 16 (April 2011) (“Canmar Ice Strengthened Drillships – Four Canmar Explorer Series ice strengthened drillships were eventually modified for use. The main shortcoming of these systems was their fixed orientation mooring system which was susceptible to move-off’s when they encountered ice beam-on. Three of the four drillships had anchor wires passing through the waterline which further exacerbated the move-off frequency due to ice interaction with the mooring lines... **Their limited ice class coupled with their station-keeping issues curtailed their effective drilling season to ~100 days.**”(emphasis added).

<sup>31</sup> 30 C.F.R. § 250.417 (“If you plan to use a MODU, you must provide: (a) Fitness requirements. You must provide information and data to demonstrate the drilling unit’s capability to perform at the proposed drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons.”); 30 C.F.R. § 250.417 (“(c) Frontier areas. ... (2) If you plan to drill in a frontier area, you must have a contingency plan that addresses design and operating limitations of the drilling unit. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of drilling or rig operations to remedy various operational or environmental situations (e.g. vessel

Curtailment Plan (COCP) that provides specific thresholds for ice conditions, weather and other constraints beyond which exploration activities will be curtailed for any exploration activities in the Alaska OCS.<sup>32</sup> More information is required, as well, to demonstrate that the Discoverer drillship (a 35\_year old bulk carrier converted to drill) is the Best Available and Safest Technology (BAST) for Beaufort Sea Exploration Operations.<sup>33</sup> Use of a drilling rig that is not capable of operating in anticipated ice conditions poses an unreasonable risk of pollution.<sup>34</sup> Also, Shell must be able to perform in accordance with the EP.<sup>35</sup> Finally, BOEMRE's EP decision must verify that OCSLA standards have been met and the exploration activity is safe.<sup>36</sup>

The EP must demonstrate that Shell has planned and is prepared to conduct the exploration activities in a manner that is safe, and in compliance with federal regulations,<sup>37</sup> thus the COCP should be modified to articulate clear thresholds regarding vessel's operating capacities with respect to severe weather or ice conditions. BOEMRE must require Shell to provide data on the weather severity, up to and including the time to drill a relief well and then correlate the weather severity to the maximum operating capability of the drill ships and support vessels to ensure that they are capable of operating in the expected conditions.

Finally, there should be clear standards for what conditions require the drilling vessel to curtail drilling or relief well operations. Currently, Shell's Critical Operations Curtailment Plan provides very little substance on any actual decision making thresholds. Instead, Shell has deferred that work to a later time, and left all such decisions to its own discretion.<sup>38</sup> The COCP

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motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

<sup>32</sup> 30 C.F.R. § 250.220 ("If you propose exploration activities in the Alaska OCS Region, the following planning information must accompany your EP: (a) Emergency plans. A description of your emergency plans to respond to a blowout, loss or disablement of a drilling unit, and loss of or damage to support craft. (b) Critical operations and curtailment procedures. Critical operations and curtailment procedures for your exploration activities. The procedures must identify ice conditions, weather, and other constraints under which the exploration activities will either be curtailed or not proceed.")

<sup>33</sup> 30 C.F.R. §250.107(c).

<sup>34</sup> 30 C.F.R. §250.300 ("Pollution Prevention (a) During the exploration, development, production, and transportation of oil and gas or sulphur, the lessee shall take measures to prevent unauthorized discharge of pollutants into the offshore waters. The lessee shall not create conditions that will pose unreasonable risk to public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.ocean.").

<sup>35</sup> 30 C.F.R. §250.281.

<sup>36</sup> 30 C.F.R. §250.202.

<sup>37</sup> 30 C.F.R. § 250.202.

<sup>38</sup> EP, Appendix J, at 5 ("Wind and sea states can affect vessel motion (e.g., heel, pitch, roll, and heave) beyond safe operating limits and/or create conditions that make certain operations unsafe. Wind and currents can also result in ice movement that creates an unsafe condition for the vessel. Conditions for curtailment activities will depend on the performance of the drilling vessel in the open water of the Beaufort Sea. The drilling vessel behavior will be thoroughly analyzed upon mooring on the first drill site location, and it will be reevaluated as needed during exploration drilling operations. Thresholds will be established for weather and sea conditions that will control:

“must identify ice conditions, weather, and other constraints under which the exploration activities will either be curtailed or not proceed.”<sup>39</sup> This planning information “must accompany [the] EP.”<sup>40</sup> Shell’s failure to identify specific conditions is therefore a failure to satisfy OCSLA regulations.

## **V. Loss or Damage to Support Vessels**

Shell is required to describe its plans for responding to the loss or damage to support craft.<sup>41</sup> Neither the EP nor ODPCP describes Shell’s plans for responding to the loss or damage to support vessels, including ice breakers, oil spill response vessels, Arctic Capping and Containment Vessel or other support vessels.

For example, Shell does not explain how it would:

- Store oil if the single oil tanker planned to hold more than 90% of Shell’s recovered oil during an oil spill was lost or damaged;
- Provide ice breaker support to maintain safe drilling operations, well control operations, or oil spill response operations if its ice breaking vessels were lost or damaged;
- Provide Arctic Capping and Containment Vessel operations if this vessel was lost or damaged; or
- Provide sufficient skimming and storage capacity to meet the WCD and State Response Planning Standard (RPS) if any of the oil spill response vessels are lost or damaged.

BOEMRE should require Shell to modify its EP and ODPCP to describe its plans for responding to the loss or damage to support craft, including its ice breakers, oil spill response vessels, Arctic Capping and Containment Vessel and other support vessels.

## **VI. Blowout Preventer Age & Condition**

Shell’s proposed blowout prevention program includes the use of two sets of blind/shear rams in each BOP. Shell also proposed to increase the frequency of BOP performance tests from 14 days to 7 days, and includes remotely operated vehicle (ROV) control panel on the seafloor with sufficient pressured water-based fluid to operate the BOP.<sup>42</sup> This proposed BOP control program provides a number of improvements over Shell’s previously

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equipment preparation to curtail operations; decision to cease drilling; hanging off drillstring or otherwise suspending the well; disconnecting riser; and moving the drilling vessel off the drill site.”)

<sup>39</sup> 30 C.F.R. §250.220.

<sup>40</sup> 30 C.F.R. §250.220.

<sup>41</sup> 30 CFR §250.220(a).

<sup>42</sup> EP at 12-3.

proposed BOP control programs. However, NSB has repeatedly requested, and has not been provided information from Shell, on the age, manufacturer name and condition of the BOP's planned for use on the Kulluk and Discoverer. The age and condition of the BOP's is critical information needed to evaluate whether the BOP meets BOEMRE's best available and safest technology (BAST) standard.<sup>43</sup>

For example, the Kulluk was built in 1983. In the absence of data from Shell to explain the BOP age, NSB assumes that Shell is planning to use the original BOP's that would now be over 28 years old. Because the Kulluk has not drilled a well for over 18 years, these BOP's have been sitting idle in the corrosive offshore arctic conditions of the Canadian Beaufort for most of that time. It is important to increase the frequency of inspections and certifications as the BOP ages. BOP's are subject to corrosion, erosion and mechanical fatigue. These risk factors increase with time, exposure to marine conditions, and can be affected by use (number of wells drilled and exposure to pressure, temperature and use (wear)), or can be affected by period of non-use (where flanges and seals dry and crack). BOEMRE should require Shell to provide information on the BOP age and condition sufficient to allow BOEMRE to determine whether the proposed BOP systems are BAST.

The EP does not demonstrate that Shell has planned and is prepared to fully comply with BOEMRE's NTLs. BOEMRE must require Shell to meet all the NTL 2010-N05 requirements, and BOEMRE must independently verify that these requirements have been met.<sup>44</sup>

It is unclear if Shell has met all of the NTL 2010-N06 standards, or whether BOEMRE has independently verified whether these requirements have been met, including: relocation of the BOP stack remotely-operated vehicle ("ROV") hot stab from the bottom of the BOP to the top in order to improve its availability (source control and containment); a redundant ROV hot stab panel 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 (source control and containment); and redundant ROV and diver capability on a support vessel, along with launch and recovery systems for each.

In 2010, BOEMRE put in place new regulations at 30 C.F.R. §250.416(f) that requires independent third party verification to ensure that subsea BOPs are designed for the specific

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<sup>43</sup> 30 C.F.R. § 250.107(c) (<sup>43</sup> Shell is required to use the best available and safest technology (BAST) whenever practical on all exploration operations to avoid failure of equipment that would have a significant effect on safety health or the environment).

<sup>44</sup> NTL 2010-05 (requires: well control system equipment to be properly maintained and capable of shutting in the well during emergency operations; blowout Preventers (BOPs) be able to perform their designated functions; a review of rig drilling, casing, cementing, well abandonment, and completion practices to ensure that well control is not compromised at any point while the BOP is installed on the wellhead; review of all emergency shutdown and emergency well control operation procedures; and verify all personnel involved in well operations are properly trained and capable of performing their tasks under both normal drilling and emergency well control operations).

equipment on the rig and for the specific well design; that the BOP stack has not been compromised or damaged from previous service; and that the BOP will operate in the conditions for which it will be used. BOEMRE must ensure that the independent third party verifications are completed because it must ensure that Shell is “prepared” to carry-out the EP.<sup>45</sup>

BOEMRE has also added new regulations at 30 C.F.R. §250.442 that require 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; minimum requirements for personnel authorized to operate critical BOP equipment; and a requirement for the blind-shear rams to be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures. Shell’s BOPs must be inspected to demonstrate compliance.

In both the US (Macondo blowout)<sup>46</sup> and Australia (Montara blowout)<sup>47</sup> it was found that government regulators were not trained and qualified to know whether the well construction design and BOP system were appropriate for the planned well conditions. The UK requires an independent engineering expert review to examine the well construction and safety design.<sup>48</sup> BOEMRE should hire an independent engineering expert to review Shell’s plan, or provide the credentials of BOEMRE staff completing this review. BOEMRE’s EP decision should set out the agency’s planned BOP testing and inspection program for Shell’s BOPs.

More advanced BOP systems may become available. Chevron has been developing improved BOP system controls for the arctic called the Alternative Well Kill System (AKWS). Chevron describes the system:

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.<sup>49</sup>

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<sup>45</sup> 30 C.F.R. §250.202.

<sup>46</sup> National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling.(2011).

<sup>47</sup> Australia Commission of Inquiry, Montara Well Blowout (2010-2011)..

<sup>48</sup> UK Deepwater Drilling—Implications of the Gulf of Mexico, Oil Spill ,UK Commission’s Findings on the Macondo Well Blowout, House of Commons, Energy and Climate Change Committee.(2011).

<sup>49</sup> Chevron Canada Limited, Canadian, National Energy Board Arctic Offshore Drilling Review AODR Submission Part 1: Briefing Document, at 25 (Apr. 2011).

NSB requests that BOEMRE consult with Chevron on the status of the AWKS system to determine if the system will be built, tested and commercially available in time for Shell's drilling program. If so, and if BOEMRE determines it is BAST, BOEMRE should require Shell to use this technology to improve safety and well control.

## **VII. Drilling Vessel Condition and Associated Equipment**

BOEMRE has the authority to conduct inspections of exploration drilling equipment<sup>50</sup> to verify that Shell is conducting operations according to the Act, the regulations, the lease, and approved EP and other applicable laws and regulations. And, BOEMRE is required to examine Shell's EP to determine whether the performance standards of 30 C.F.R. §250.202 have been met, including a determination of whether the equipment is safe and whether it will not cause undue or serious harm or damage to the human, marine or coastal environment.<sup>51</sup>

BOEMRE should inspect the drilling rigs and associated equipment to verify that the equipment meets BOEMRE's best available and safest technology (BAST) standard,<sup>52</sup> and that the public representations made by Shell about the quality, condition, repairs and upgrades made to the Discoverer and Kulluk have actually been completed.<sup>53</sup> NSB staff and experts toured the Kulluk on March 1, 2011 and found the rig was not in drill-ready condition, and that many of the drilling rig upgrades and improvements Shell had publically announced had not been done or were not in place. The condition of the Discoverer is also unclear. Shell has reportedly upgraded this temperate water drillship to operate in Arctic ice conditions, but no state or federal agency has boarded the Discoverer,<sup>54</sup> inspected it or verified whether Shell's reported upgrades have actually been completed. Additionally, in May 2011 the Discoverer was damaged during a storm, and is reported to be undergoing repairs at this time.<sup>55</sup>

BOEMRE and Coast Guard inspections should be completed prior to approving the Exploration Plan (EP), or at a minimum, make satisfactory inspections a condition of EP

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<sup>50</sup> 30 C.F.R. § 250.130.

<sup>51</sup> 30 C.F.R. §§ 250.232, .202

<sup>52</sup> 30 C.F.R. § 250.107(c) (<sup>52</sup> Shell is required to use the best available and safest technology (BAST) whenever practical on all exploration operations (30 CFR 250.107(c)) to avoid failure of equipment that would have a significant effect on safety health or the environment).environment.

<sup>53</sup> Also, where a drilling vessel has not been proven for use in the proposed environment, BOEMRE can require a third-party review of the units design. 30 C.F.R. § 250.417 ("(c) Frontier areas. (1) If the design of the drilling unit you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the unit's design.") Shell's planned use of the Discoverer drillship would be its first operation in the Arctic, the drillship therefore is not a proven arctic drilling rig.

<sup>54</sup> NSB has inquired if BOEMRE, State of Alaska and/or USCG staff have boarded the Discoverer and verified its conditions; all report that they have not.

<sup>55</sup> Rob Maetzig, Twinkle, Twinkle, Damaged Drillship, Taranaki Daily News Online (May 11, 2011).

approval that must be completed by the end of 2011. This way, BOEMRE can require Shell to improve its EP or attach conditions of approval to BOEMRE's EP decision to ensure federal laws and regulations have been satisfied. This will also ensure that it is prudent for BOEMRE and the USCG to complete a thorough inspection of the Kulluk and Discoverer and associated equipment to verify that the equipment is Best Available and Safest Technology (BAST), and to verify all upgrades and repairs have been made prior to approving the EP, or at a minimum make these inspections a condition of EP approval that must be completed by the end of 2011. This way there will be time to make any additional upgrades and repairs that BOEMRE and the USCG may require before the proposed 2012 drilling season.

In the meantime, Shell should be required to provide more information on the Kulluk and Discoverer drilling rig equipment to ensure that the equipment is BAST. For each of the major systems and components of the drilling rig, Shell should be required to provide a description of the system/component and its current condition; the manufacturer name and date of installation; an explanation of whether the equipment is best available arctic drilling technology or whether improved equipment is commercially available and whether Shell plans to upgrade any equipment or an explanation as to why not; the date of last calibration, certification, inspection, audit and credentials of the person performing the work; and verification that the system/component is in drill ready condition and/or a description and timeline for any additional upgrades or repairs required to bring system/component to drill ready condition.

Whenever inspections are conducted, BOEMRE and the USCG should provide a written summary of its inspections, findings and recommendations, along with the credentials of the BOEMRE and USCG staff or experts used. BOEMRE should verify that any recommended repairs or upgrades are completed before the 2012 drilling season. And finally, NSB requests the opportunity to send a NSB representative to observe the BOEMRE and USCG inspections of the Kulluk and Discoverer drilling rigs and associated equipment.

### **VIII. Agency Inspections of Shell's Exploration Operations**

BOEMRE has the authority to conduct inspections of exploration equipment to verify that Shell is conducting operations according to the Act, the regulations, the lease, and approved Exploration Plan and other applicable laws and regulations.<sup>56</sup>

BOEMRE should explain, in its EP decision, plans for initial inspections of all equipment that will be used in Shell's Exploration Program and provide a schedule and explanation of the resources that will be assigned to routine inspections during the course of the Exploration

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<sup>56</sup> 30 C.F.R. §CFR 250.130250.130.

Program implementation. BOEMRE should also explain how it will coordinate its inspection program with other state and federal agencies,<sup>57</sup>

Because the Department of Interior (DOI) is building a new inspection program within the Bureau of Safety and Environmental Enforcement (BSEE) to commence on October 1, 2011, BOEMRE should provide the credentials of the staff (or the independent experts) who will be assigned to inspection and enforcement work. This information is needed to address a key finding of the National Commission on the BP Deepwater Horizon Oil Spill that the DOI lacked the expertise, training and qualifications to inspect OCS Exploration Operations:

Agency personnel naturally look to agency leadership to signal what constitutes their primary mission, including the expertise and experience that such leaders bring with them. In the case of MMS, those signals were profoundly disturbing, yet nonetheless consistent over time. No one who has led MMS since it was created almost 30 years ago has possessed significant training or experience in petroleum engineering or petroleum geology, or any significant technical expertise related to drilling safety. In the absence of a clear statement from the top about the necessity for such expertise to ensure drilling safety, it should be no surprise that MMS personnel have suffered from the loss of essential expertise throughout their ranks. Indeed, the lack of requisite training is abysmal. According to a recent survey conducted at the request of the Secretary of the Interior, “[a]lmost half of the [MMS] inspectors surveyed do not believe they have received sufficient training.

MMS, unlike Interior’s Bureau of Land Management (which inspects onshore oil and gas drilling operations), has no “oil and gas inspection certification program” and no exam “is required of each inspector in order to be certified.” MMS “does not provide formal training specific to the inspections process, and does not keep up with changing technology. Some inspectors noted that they rely on industry representatives to explain the technology at a facility.”<sup>58</sup>

While DOI’s new BSEE division is an attempt to remedy this lack of staff expertise, training and qualifications, this program will only be in its infancy during Shell’s proposed 2012 EP. Therefore, NSB believes it raises a legitimate concern and question for BOEMRE to address regarding its inspection plans for Shell’s 2010 Exploration Program.

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<sup>57</sup> National Commission Report on the BP Deepwater Horizon, Oil Spill, at 255.(2011) (“All of these problems were compounded by an outdated organizational structure, a chronic shortage of resources, a lack of sufficient technological expertise, and the inherent difficulty of coordinating effectively with all the other government agencies that had statutory responsibility for some aspect of offshore oil and gas activities.”).

<sup>58</sup> National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling , at 74 (2011).

Furthermore, the National Commission on the BP Deepwater Horizon Oil Spill found that the Minerals Management Service (MMS) lacked rules, regulations, policies and practices for inspections, nor does it have a comprehensive handbook addressing inspector roles and responsibilities:

Perhaps because of the cumulative lack of adequate resources, absence of a sustained agency mission, or sheer erosion of professional culture within some offices, MMS came progressively to suffer from serious deficiencies of organization and management: the fundamental traits of any effective institution. According to the Outer Continental Shelf Safety Oversight Board,\* MMS lacks “a formal, bureau-wide compilation of rules, regulations, policies, or practices pertinent to inspections, nor does it have a comprehensive handbook addressing inspector roles and responsibilities.” As a result, the Board concluded, “policies and enforcement mechanisms vary among the [Gulf of Mexico] districts and the regions, and there is no formal process to promote standardization, consistency, and operational efficiency.”<sup>59</sup>

The lack of any formalized written inspection program is a serious short-coming. BOEMRE should explain what steps it has taken to develop policies and practices for Arctic OCS inspections and a comprehensive handbook for inspector roles and responsibilities.<sup>60</sup> No exploration work should be allowed until BOEMRE has completed its rules, regulations, policies and practices for inspections and the details of the inspection program are made public.

#### **IX. C-Plan Distribution**

NSB requests a copy of the final oil spill prevention and contingency plan for the Camden Bay facility be distributed to NSB’s Director of Planning and Community Services.

#### **X. Worst Case Discharge (WCD) Scenario**

Shell’s EP must be modified because it fails to include complete and credible worst case discharge and oil spill response information required to accompany the EP by 30 C.F.R. §§250.212(g), 212(h), 213(g), 219, and 220; Nor does the EP demonstrate that the company has planned and is prepared to comply with the oil spill response planning requirements of 30 C.F.R. Part 254 or NTL 2010-N10, “applicable implementing regulation[s].”

##### **a. WCD Flowrate**

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<sup>59</sup>National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling,, at 78. (2011).

<sup>60</sup> NSB requests a copy of this documentation.

30 C.F.R. §§250.212(g) and 250.219(a) require an Oil Spill Response Plan formulated in conformance with the requirements of 30 C.F.R. Part 254. 30 C.F.R. §254.26(a) requires a discussion of “the volume of [the] worse case discharge scenario determined using the criteria in §254.47.” 30 CFR § 254.47 (b), in turn, explains:

For exploratory or development drilling operations, the size of your worst case discharge scenario is the daily volume possible from an uncontrolled blowout. In determining the daily discharge rate, you must consider any known reservoir characteristics. If reservoir characteristics are unknown, you must consider the characteristics of any analog reservoirs from the area and give an explanation for the selection of the reservoir(s) used. Your scenario must discuss how to respond to this well flowing for 30 days as required by § 254.26(d)(1).<sup>61</sup>

In their 2009 and 2010 ODPCP submissions, Shell represented that:

“Because there are no relevant well data or other supporting technical documentation to estimate the simulated blowout rate of the exploration well, the daily rate is based on the ADEC response planning standard of 5,500 bopd.”<sup>62</sup>

In contrast, with this ODPCP Shell does estimate site specific blowout rates for the four wells. Shell estimates that the highest blowout flowrate for the four wells proposed under this EP,<sup>63</sup> would occur at the Torpedo H location (9,468 bopd). While this site specific flowrate estimate is an improvement from the 2009 and 2010 ODPCPs, Shell has requested that all geological and geophysical data to support it be held confidential,<sup>64</sup> NSB is therefore unable to independently assess the accuracy of this new estimated blowout rate. Consequently, we emphasize the need for BOEMRE to rigorously review the underlying data and calculations. BOEMRE should provide expert review of the proposed blowout flowrate to verify that it meets the requirements of NTL 2010-06<sup>65</sup> and 20 CFR 254. Furthermore, we request that BOEMRE provide an explanation of the credential of the expert reviewers and their findings. If BOEMRE discovers any shortcomings in Shell’s estimate, the agency should require modification of the EP, as required by OCSLA’s implementing regulations.

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<sup>61</sup> (emphasis added).

<sup>62</sup> ODPCP at 1-60 (where the quoted language was deleted from the existing ODPCP and replaced with a new estimate of 16,000 bopd) (emphasis added).

<sup>63</sup> Sivulliq G. &, Sivulliq N., Torpedo H and Torpedo J.

<sup>64</sup> EP at 3-1.

<sup>65</sup> NTL 2010-N06 (requires the operators to: develop a blowout scenario for the highest potential volume of liquid hydrocarbons; specify as accurately as possible the time it would take to contract for a rig, move it on site, and drill a relief well, including the possibility of drilling a relief well from onshore; and described all the assumptions and calculations used to determine the Worst Case Discharge (WCD) e.g. well design, reservoir characteristics, fluid characteristics, and pressure, volume and temperature characteristics, and supporting calculations and models used).

## b. WCD Adverse Weather Conditions

Shell's WCD discharge analysis and response discussion is fundamentally flawed because it fails to incorporate "adverse weather conditions." Shell plans to drill from July 10 to October 31.<sup>66</sup> Some of the most significant adverse weather conditions would occur later in the proposed drilling period. But Shell avoids discussing these significant adverse weather conditions by defining a WCD as a spill commencing on August 1 and continuing until August 30. And even within summer months the scenario utilizes average weather conditions rather than "adverse" conditions. The WCD description of "adverse weather conditions" would also be improved by use of more comprehensive or more current weather data.

The WCD scenario required by OCSLA regulations must incorporate "adverse weather conditions" and maximize the spill area. 30 C.F.R. §254.26 requires:

The discussion of your worst case discharge scenario must include all of the following elements: .... (d) A discussion of your response to your worst case discharge scenario in adverse weather conditions."<sup>67</sup>

Adverse weather conditions are defined as:

[W]eather conditions found in the operating area that make it difficult for response equipment and personnel to clean up or remove spilled oil or hazardous substances. These include, but are not limited to: Fog, inhospitable water and air temperatures, wind, sea ice, current, and sea states. It does not refer to conditions such as a hurricane, under which it would be dangerous or impossible to respond to a spill.<sup>68</sup>

30 C.F.R. §254.26 further requires: "The trajectory analysis chosen must reflect the maximum distance from the facility that oil could move."

Some adverse weather conditions found in Camden Bay during the period of Shell's proposed operations and spill response period that would make it difficult for response equipment and personnel to clean up or remove spilled oil include: varying concentrations of sea ice or the presence of ice floes, strong winds pushing spilled oil toward shorelines,<sup>69</sup> and

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<sup>66</sup> ODPCP at 1-64, 1-68.

<sup>67</sup> 30 C.F.R. § 254.26 (emphasis added).

<sup>68</sup> 30 C.F.R. § 254.6.

<sup>69</sup> Winter storms can bring strong west winds pushing some oil to the east, and strong north-east storms that will rapidly move oil to the south-west, quickly soiling barrier islands and the coastline with oil. For example, BP's Northstar ODPCP shows a very significant difference between summer and winter wind roses, and its impact on oil spill spreading.

limited visibility due to frequent dense fog and diminishing daylight hours. These adverse weather conditions would impact response efforts most significantly in the case of a spill occurring on October 31 and continuing into November and December.

The challenges of late season spill response are illustrated by Shell's description of general strategies for cleaning up oil on October 1.<sup>70</sup> This "Response Strategy" generally describes Shell's inability to respond to an oil spill, rather than its ability to recover oil. For example Shell describes the "*impossibility*" of mechanical response in most conditions encountered even if a spill were to occur on October 1:

As freeze-up continues and blowing snow begins to accumulate on young ice, it becomes impossible to operate the physical containment and recovery systems safely and effectively. Small workboats and barges and the 47-foot skimmer are loaded onto the larger OSRB. ACS boats return to Prudhoe Bay.

As offshore operations move into the second week of response, the hours of daylight and average air temperatures continue to drop, making oil surveillance and tracking more difficult, along with the location, containment, and recovery of oil.

During the second week of response (Day 8 to Day 14), the formation of grease ice and nilas (e.g., a thin elastic crust of ice up to 10 centimeters thick that bends easily under pressure) make it increasingly difficult to work with booms as they begin to fill with ice, preventing the effective collection of oil.

Oil encounter rates are substantially reduced, and the large OSRB, together with the smaller skimming vessels (the 47-foot boat with built-in Lamor brushes, the ACS skimming workboats, and the vessel of opportunity), are limited to spot removal techniques in the heaviest of concentrations.

As freeze-up continues and blowing snow begins to accumulate on young ice, it becomes impossible to operate the physical containment and recovery systems safely and effectively.<sup>71</sup>

Given the substantial challenges Shell outlines to spill response in October, it is clear that, a summer oil spill scenario commencing on August 1 does not meet the adverse weather conditions requirement of 30C.F.R. §254.26(d). These October conditions "make it difficult for response equipment and personnel to clean up or remove spilled oil."

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<sup>70</sup> ODPCP at 1-101 (Note that this "Response Strategy" is not a fully developed WCD discussion containing all of the elements required by 30 C.F.R. §254.26.).

<sup>71</sup> ODPCP at 1-104.

OCSLA regulations require an OCS operator to submit an Oil Spill Response Plan to demonstrate that the activities can be conducted in compliance with federal law. A response plan that indicates response methods are ineffective for a substantial portion of the proposed operating period may as well be no response plan at all.

In addition to failing to identify the season with adverse weather conditions, Shell's August 1<sup>st</sup> WCD scenario does not describe adverse summer weather conditions. The WCD describes temperature and wind averages, and then uses the average for each day of their scenarios. Average weather conditions are not representative of the adverse weather conditions.

Furthermore, the wind averages and directions described in the August WCD scenario are set up in a manner that facilitates oil recovery. Maintaining a constant wind speed of 10mph, with directionality changing approximately every 3-4 days, the wind for Shell's WCD tends to keep the oil away from shoreline. This use of averages does not present adverse weather conditions as defined in 30 C.F.R. §254.6. In fact, 30 C.F.R. §254.26(b) requires that the wind trajectory chosen, "[M]ust reflect the maximum distance from the facility that oil could move in a time period that it reasonably could be expected to persist in the environment." The current wind trajectory does not reflect the maximum distance that the oil could move during the time period. BOEMRE must require Shell to use appropriate adverse wind conditions which create the maximum spread for the WCD scenarios. Another major flaw with the current WCD is that the weather data used is outdated. Wind and weather data used in Shell's oil spill trajectory modeling is over 23 year old. Shell uses summer (August 1<sup>st</sup> to 30<sup>th</sup>) wind data from Barter Island, collected in 1971 to 1988.<sup>72</sup> Shell's oil spill trajectory should be based on more current wind data and should use wind data for the appropriate WCD time period (late October through November). The need for more recent data is most critical in the Arctic where climate change is most acute.<sup>73</sup> Shell should be required to use more current data..

There are numerous sources of historical weather data easily available. For example, sea ice data is available from the National Snow and Ice Data Center website ([http://www.natice.noaa.gov/products/weekly\\_products.html](http://www.natice.noaa.gov/products/weekly_products.html)). And weather data is readily available from the National Climate Data Center (NCDC) online at <http://www7.ncdc.noaa.gov/IPS/cd/cd.html;jsessionid=493D4CF6E2825847F7C1F81DBD73C588>.<sup>74</sup> And, storm data is also available from NCDC, online at <http://www4.ncdc.noaa.gov/cgi->

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<sup>72</sup> EP at 8-3 (National Weather Service station, 1971-1988, (<http://climate.gi.alaska.edu/>)).

<sup>73</sup> See e.g. Wendler, G. et al., Beaufort Sea Ice Concentration and the Climate of the Alaskan North Slope (Dec. 2002) ("Temperature and sea ice concentration measurements indicate a significant climate change in recent decades in the Western Arctic.").

<sup>74</sup> National Climate Data Center (NCDC), <http://www7.ncdc.noaa.gov/IPS/cd/cd.html;jsessionid=493D4CF6E2825847F7C1F81DBD73C588> (last visited July 25, 2011).

win/wwcgi.dll?wwEvent~Storms.<sup>75</sup> Even a brief examination of storm data in the past few years shows that in September and November of 2010 Barter Island experienced storms with wind speeds up to 45 knots (51.8 mph) and 58 knots (66.7 mph), respectively. In contrast, the WCD scenario describes “average wind speed is 10 mph or 8-9 knots.”<sup>76</sup>

The ODPCP does not adequately address the “adverse weather conditions” element of the WCD scenario. Table 1-12, “Summary of How the Worst-Case Discharge Scenario Complies with BOEMRE Regulations,” does not have any information regarding how the conditions assumed in the WCD scenario comply with the “adverse weather condition” requirement of 30 C.F.R. §254.26 (d).<sup>77</sup> Shell’s WCD oil spill scenario analyzes a spill in August, and describes seas states and ice and wind conditions that are favorable even for summer, and substantially more favorable than late October weather conditions. BOEMRE must require Shell to provide a late October WCD as required by the standard articulated in 30 C.F.R. §254.26(d).

### C. WCD Trajectory Analysis

30 C.F.R. §254.26 requires that the WCD scenario include a spill trajectory analysis:

The discussion of your worst case discharge scenario must include all of the following elements: ... (b) An appropriate trajectory analysis specific to the area in which the facility is located. The analysis must identify onshore and offshore areas that a discharge potentially could affect. The trajectory analysis chosen must reflect the maximum distance from the facility that oil could move in a time period that it reasonably could be expected to persist in the environment.

Shell’s oil spill trajectory<sup>78</sup> underestimates the potential Worst Case Discharge (WCD)<sup>79</sup> spill size, area of impact, and amount of nearshore and shoreline oiling that will occur. A number of factors contribute to this underestimate, including (1) limiting the trajectory period to 72 hours and (2) using average summer meteorological data. Furthermore, the trajectory modeling software has apparent short-comings, including the failure to account for the physical characteristics of oil after it has traveled from the seafloor. The trajectory analysis is also suspect because although the volume is three times greater than the volume considered in the previous ODPCP, the size of the oil slick has not increased proportionately.

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<sup>75</sup> National Climate Data Center (NCDC), <http://www4.ncdc.noaa.gov/cgi-win/wwcgi.dll?wwEvent~Storms> (last viewed July 25, 2011).

<sup>76</sup> ODPCP at 1-64.

<sup>77</sup> ODPCP at 1-61.

<sup>78</sup> ODPCP at 1-83.

<sup>79</sup> 30 C.F.R. §§ 250.219, 254.26 (Shell is required to develop a worst case scenario that could result from its exploration activities).

**72 Hours:** Shell's ODPCP only shows the oil spill trajectory for the first 72 hours of the spill. After 72 hours, the ODPCP unrealistically assumes that most of the oil has been cleaned up.<sup>80</sup> This is contrary to 30 C.F.R. §254.26(b) which requires that the trajectory analysis cover "a time period that [spilled oil] reasonably could be expected to persist in the environment." Spilled oil will persist in the environment for longer than 72 hours, even with spill response efforts underway. This is true for a spill at any time, but especially for a spill in sea ice conditions, strong winds, or other adverse weather conditions.

The unrealistic 72 hour clean up assumption leads to the conclusion that minimal shoreline oiling will occur. Thus, it results in a failure to meet the requirement that the analysis "identify onshore and offshore areas that a discharge potentially could affect." Long term trajectories would more realistically identify the areas that could be impacted by unrecovered oil.

NSB requests that Shell be required to provide a series of time-sequenced oil spill trajectory estimates for the period of 72 hours, 15 days, one month and two months and continuing for the time period that it reasonably could be expected to persist in the environment.<sup>81</sup>

**Summer Data:** Because Shell uses summer meteorological data to provide the basis for the WCD trajectory, ignoring the "adverse weather condition" requirement, the trajectory assumes that oil will parallel the Beaufort Sea shoreline and will have a low potential for contacting barrier islands and shorelines between Cross Island and Barrow.<sup>82</sup> Shell's use of calmer summer meteorological data is not representative of a WCD and underestimates the nearshore and shoreline impacts that will occur during a late season oil spill. Shell should provide an oil spill trajectory showing nearshore and shoreline impacts based on realistic response capability in arctic conditions in November and December when the WCD may occur, and the movement of oil trapped under ice subject to subsea currents.

**Modeling Software:** The Response Group, of Houston, Texas, conducted the oil spill trajectory modeling for Shell using OilMap software.<sup>83</sup> The ODPCP does not provide technical justification to support use of this model to predict a subsea arctic well blowout in ice conditions. It is well known that better trajectory modeling is needed to develop more realistic oil spill planning scenarios because current models do not accurately predict subsea spills or oil and ice interactions.<sup>84</sup>

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<sup>80</sup> ODPCP at 1-64, 1-68.

<sup>81</sup> 30 C.F.R. § 254.26 (b).

<sup>82</sup> EP at 8-4.

<sup>83</sup> ODPCP at 1-60, 1-64, 1-69.

<sup>84</sup> Pew Environment Group, Oil Spill Prevention and Response in the U.S. Arctic Ocean, Unexamined Risks, Unacceptable Consequences, prepared by Nuka Research and Planning Group, LLC., November 2010, at Chapter 7.1.3. (Nov. 2010) (. concludes: *"from a planning perspective, the inability to model oil trajectories during various*

Shell should be required to provide technical justification to verify that the OilMap software is an appropriate tool for modeling an arctic subsea well blowout. BOEMRE and NOAA should review this model in detail and independently verify that it is appropriate for this use.

**Oil Characteristics:** Shell's modeling work does not show the time it would take for oil and gas to travel from the subsea wellhead to the surface, and the composition and characteristics of the oil once it reaches the surface (e.g. viscosity, emulsification, etc.). In shallower marine waters, the gas released along with the oil plays a major role in establishing a wide and relatively thin initial slick. The rising gas entrains a significant amount of water causing the oil to spread laterally.<sup>85</sup>

The location, composition, and physical characteristics of the spilled oil will be critical factors in determining possible oil recovery methods. For example, oil trapped under ice will not be readily available for mechanical recovery or burning. Thin emulsified oil slicks will not burn. Thin oil slicks will require booming operations to thicken oil to a point where mechanical recovery or burning might be possible, however, booming will not be possible in ice concentrations over 3/10<sup>ths</sup>. Therefore, it is not only important for Shell to provide an estimated map of the oil spill impact area, but it is critical to understand the environmental conditions that will be encountered and the physical properties of the spilled oil to estimate response efficacy.

**Volume:** Shell's ODPCP states it revised its oil spill trajectory analysis to reflect a WCD blowout from 5,500 bopd to 16,000 bopd, however, the oil spill trajectory<sup>86</sup> reflects little change. Shell's previous 5,500 bopd oil spill trajectory estimated a maximum oil spill extent of 90 miles by 4 miles wide.<sup>87</sup> Shell's new oil spill trajectory for a spill over three times larger (16,000 bopd) shows little difference with the oil slick estimated at 93 miles by 4.5 miles wide.<sup>88</sup> This appears to be a very significant flaw in the oil spill trajectory mapping estimate that needs BOEMRE's close attention.

**Impacts:** Oil spill trajectories would likely follow currents and routes coincident to the migratory paths used by Beluga and Bowhead Whales. During the fall migration, bowhead and beluga whales follow prevailing wind and ocean currents traveling west from Kaktovik toward

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*ice conditions makes it almost impossible for operators or regulators to assess the potential risks from a major oil spill, because we cannot reliably predict where an oil spill would travel and which resources might be affected.”).*

<sup>85</sup> Imperial Oil Resources Ventures Limited, Beaufort Sea Exploration Program EL 446 and EL 449 Joint Venture, Public Review Of Arctic Safety and Environmental Offshore Drilling Requirements Submission for CFI No. 1 and CFI No. 2, Submitted to: Canada National Energy Board (Apr. 2011).

<sup>86</sup> ODPCP at 1-83.

<sup>87</sup> Shell 2010 ODPCP.

<sup>88</sup> Shell 2010 ODPCP.

Barrow and then into the Chukchi Sea. This pattern has been observed during aerial surveys<sup>89</sup> and by satellite tagging studies<sup>90</sup>. This information is relevant to the review of Shell's proposed activities because it suggests the whales would be traveling coincident to the trajectory of an oil spill. The National Research Council concludes that:

Oil spilled in broken-ice cannot be cleaned up effectively, and it is expected that whales would not avoid oil-fouled waters.<sup>91</sup>

Unrecovered oil could persist in the marine environment, with the potential to pollute the water column, shoreline, and sea bottom, and contaminate whale feeding grounds. Contamination could linger for years, causing irreparable cumulative damage to an extremely vulnerable sub-species. Impacts to subsistence could be long-lasting and significant.

## **XI. Oil Spill Prevention Training Program**

Shell's Prevention Training Program description lacks sufficient information to determine compliance with state regulations.<sup>92</sup> State regulations require that the ODPCP's description of the Prevention Training Program include the following:

- (1) Listing of each position with job duties and the training and level of knowledge appropriate to that position;
- (2) Listing of any licenses, certifications, or other prerequisites needed to hold each position; and
- (3) Listing of training objectives and the means of achieving them, including training subjects, schedules, frequency, and type.<sup>93</sup>

Shell's ODPCP does not include this information. Instead, Shell provides a one-page summary of its intended prevention training program and that of its contractors. This is insufficient to demonstrate that there are trained and qualified personnel who can carry out

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<sup>89</sup> Moore, S.E., DeMaster, D.P., & Dayton, P.K., Cetacean Habitat Selection in the Alaskan Arctic during Summer and Autumn. Arctic 53: 432-447 (2000)

<sup>90</sup> Suydam, R.S., Frost, K.J., & Lowry, L., Distribution and Movements of Beluga Whales from the Eastern Chukchi Sea Stock During Summer and Early Autumn, Final Report OCS Study MMS University of Alaska, Coastal Marine Institute, Fairbanks. 48 pp. 2005-035 (2005)

<sup>91</sup> National Research Council (NRC). Oil in the Sea III: Inputs, Fates, and Effects. The National Academies Press. Washington, DC. (2003).

<sup>92</sup> ODPCP at 2-1, 3-42, 3-43. The citation provided the ODPCP on page 2-1 §2.1.1 to the Alaska Administrative Code requirement for Prevention Training Programs is 18 A.A.C. §75.007(d). According to our research tools, 18 A.A.C. §75.007(d) was repealed on December 30, 2006.

<sup>93</sup> 18 A.A.C. §75.020.

highly technical oil spill prevention work, including: BOP testing, well control, corrosion monitoring and control programs, maintenance and testing of leak detection systems, and maintenance and testing alarms, and other prevention work.

Because Shell plans to employ a large number of contractors a better understanding these contractor's oil spill prevention programs and training is needed. This is especially true when the oil spill prevention commitment specified in the ODPCP is completely outsourced to a contractor, ACS, with little Shell oversight.

BOEMRE should require that the ODPCP include information required by 18 A.A.C. §75.020. Shell should provide a matrix listing the information required for a complete Prevention Training Program description. Shell should also be required to provide information on how it ensures its contractors are adequately trained on oil spill prevention.

## **XII. Statements of Contractual Terms for Personnel and Equipment**

Shell is required to provide a current Statement of Contractual Terms (SOCT) for each Oil Spill Primary Response Action Contractor it plans to use in its ODPCP.<sup>94</sup>

An oil spill primary response action contractor is defined as a person who is or intends to be obligated under contract to the holder of an approved oil discharge prevention and contingency plan issued under AS 46.04.030 to provide resources or equipment to contain, control, or clean up an oil discharge.<sup>95</sup>

Shell's ODPCP, Appendix B lists some, but not all contractors it plans to use to contain, control, or clean up an oil discharge. For example, Shell plans to use Wild Well Control to provide source control personnel and equipment, but Shell does not provide a SOCT for this organization. Nor does Shell provide a SOCT for use of BPXA's West Dock facilities for logistical support during a spill response, or provide Memorandums of Understanding or Facility Sharing Agreements made to access North Slope facilities owned by other operators for spill response

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<sup>94</sup> 18 AAC § 75.445(i) ("If a plan holder proposes to use the services of an oil spill primary response action contractor to meet a requirement of AS 46.04.030 or 18 AAC 75.432 - 18 AAC 75.442, the contractor must be registered under 18 AAC 75.500 - 18 AAC 75.580. The plan holder shall include a correct and complete list of each primary response action contractor, with name, address, telephone number, and affiliation by company, and, for each response action contract, a statement signed by the plan holder and the primary response action contractor attesting to the department that the contract (1) clearly specifies that the contractor is obligated to (A) provide the response services and equipment listed for that contractor in the contingency plan; (B) respond if B) respond if a discharge occurs; (C) notify the plan holder immediately if the contractor cannot carry out the response actions specified in the contract or the contingency plan; (D) give written notice at least 30 days before terminating its contract with the plan holder; (E) respond to a department-conducted discharge exercise required of the plan holder; and (F) continuously maintain in a state of readiness, in accordance with industry standards, the equipment and other spill response resources to be provided by the contractor under the contingency plan.")

<sup>95</sup> As used in AS § 46.04.035, 18 AAC § 75.500-.580.

activities. Additionally, Shell's ODPCP contains SOCT's that are, in some cases over five years old, dated as far back as 2006.

Shell should provide a SOCT for all contracted personnel and equipment described in its ODPCP. Shell should provide updated SOTCs that include expiration dates clearly establishing how long each agreement is valid. Each SOCT should be valid for the five year term of the C-Plan that Shell requests (2011-2016).

### **XIII. Realistic Maximum Response Operating Limits (RMROL)**

Shell's ODPCP generally references ACS Technical Manual Tactic L-7 for RMROL limits, with few exceptions.<sup>96</sup> Based on Traditional and Local Knowledge (TEK) provided by NSB staff and residents, some of the RMROL limits listed in Tactic L-7 are not appropriate for the Camden Bay area. NSB requests that Shell examine each of the concerns listed below and identify more current and accurate data for the Camden Bay area or provide justification that the data listed in L-7 is current and accurate for Camden Bay.

- The percentage of time that the daily mean temperature is -35F or less in the winter is too low.
- The percentage time that the daily mean wind speed is greater than 15 knots or more in the winter, summer, and fall is too low. The frequency of winds gusts is too low. The maximum wind speed is too low.
- The daily mean visibility of 1 mile or less is too low in all seasons. In this area we experience frequent visibility restrictions due to whiteout conditions and fog.
- The percentage of flight cancelations of 5% per month is too low for the winter and fall seasons.
- The percentage of time for whiteout conditions of 5% in the winter is too low. The frequency of winter whiteouts is much higher. The percentage of time for whiteout conditions in fall and spring is listed as 0%. That is not correct. There are white outs that occur during the fall and spring seasons.
- The over ice flow statistics are based on 1989 Endicott Environmental Monitoring Program data, which is not reflective of the Camden Bay area.
- The high water flow statistics are based on 1989 Endicott Environmental Monitoring Program data, which is not reflective of the Camden Bay area.

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<sup>96</sup> ODPCP at 3-16 (references ACS Tactic L-7 with the exception of some updated site specific information provided on break-up dates, summer season duration, and amount of landfast ice for Camden Bay).

- The percentage of time that a response vessel would experience shallow coastal waters that might impede spill response activities is listed as 0% in summer and fall seasons. This is incorrect. There are many areas of the Beaufort Sea that have shallow water that will impede spill response vessels during the summer and fall. In many areas air boats may be the only vessels that can provide access.
- The category of storm surges flooding roads and stranding vessels is listed at 1% or less during the summer and fall. We experience a much higher percentage of storm surges due to high winds and low tides in this area.
- The percentage of time when the wave height is 3' or more is listed as 5% or less in the summer and fall; this equates to up to 2 occurrences per month. This is incorrect for late summer and fall. In the late summer and fall (August – October), we commonly have high NE winds that create sea states exceeding 3' in the project area. The percentage of time that a wave height of 3' or more occurs should be increased for the summer and fall. This is important because late summer and fall conditions make mechanical response with skimmers and boom impossible a large percentage of the time.
- Icing usually occurs in the fall (August – October) and spring (April and May).
- The percentage of time darkness occurs during the winter should be increased for the very dark months of November to February, when it is essentially dark 20-24 hours per day. During these periods of intense dark, additional lighting units will be needed to guide response operations. In the fall there is a higher percentage of time in darkness than what is listed in table L-7, because data is lumped with summer statistics. Separate summer and fall statistics on the time of darkness will be very important.
- The sea ice load bearing statistics do not make sense. Table L-7 shows that the sea ice can hold heavy equipment 100% of the time in spring ice conditions, but cannot hold light equipment any time. The table shows that in summer both heavy and light equipment can cross the water, which is incorrect. The table should show that 100% of the time the sea ice load bearing capability is insufficient.
- In cold weather conditions it is ACS's standard procedure to rotate personnel every 15-30 minutes to allow for warm up time. This means that in winter conditions the number of personnel needed should be doubled.

Shell should be required to use updated site-specific RMROL data for the Camden Bay area to evaluate whether additional oil spill prevention measures are needed during certain periods and evaluate the needs for pre-staging equipment.

#### **XIV. Relief Well Plan**

Shell has proposed to drill with either the Kulluk or Discoverer from July 10 to October 31.<sup>97</sup> In the event of a well blowout, Shell proposes to drill a relief well first with the primary rig involved in the well blowout.<sup>98</sup> If the primary rig is damaged, Shell plans to bring the other rig, either the Kulluk or Discoverer, to the site to drill the relief well.<sup>99</sup> As relief well rigs, the Kulluk would be staged in Dutch Harbor and would require 18 days to transit to Camden Bay; the Discoverer would be operating in the Chukchi Sea and would require 9 days to suspend operations, retrieve mooring, and transit to Camden Bay.<sup>100</sup> Shell states either rig would require 20 to 25 days to drill a relief well depending on the prospect.<sup>101</sup>

OSCLA regulations and BOEMRE guidance require Shell to describe its plans for responding to the loss or disablement of a drilling unit and to plan for a relief well.<sup>102</sup> This plan must meet the standard applicable to all aspects of an EP set out in 30 C.F.R. § 250.202:

Your EP ... must demonstrate that you have planned and are prepared to conduct the proposed activities in a manner that:

(a) Conforms to the Outer Continental Shelf Lands Act as amended (Act), applicable implementing regulations, lease provisions and stipulations, and other Federal laws;

(b) Is safe;

(c) Conforms to sound conservation practices and protects the rights of the lessor;

(d) Does not unreasonably interfere with other uses of the OCS, including those involved with national security or defense; and

(e) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.

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<sup>97</sup> EP at 1-4.

<sup>98</sup> EP at 2-5.

<sup>99</sup> EP at 2-5.

<sup>100</sup> EP at 2-6.

<sup>101</sup> EP at 2-6.

<sup>102</sup> 30 C.F.R. § 250.220 ("If you propose exploration activities in the Alaska OCS Region, the following planning information must accompany your EP:(a) Emergency plans. A description of your emergency plans to respond to a blowout, loss or disablement of a drilling unit, and loss of or damage to support craft."); NTL 2010-N06 at 3 ("Pursuant to this NTL, you must submit the following information with your new EP ... 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.").

And, of course, BOEMRE's overarching responsibility to prevent damage to or waste of any natural resource, property, or the environment when establishing performance standards for lease operations applies to the relief well plan.<sup>103</sup>

Although Shell's Camden Bay drilling operations are beyond the three mile coastal jurisdiction of NSB, our regulatory standard highlights elements that ought to be included in the relief well plan. And, these standards are relevant because oil spilled from an OCS blowout could pollute NSB waters. NSB Municipal Code (NSBMC) sets specific standards for relief wells including the identification of a suitable drilling rig for the planned operating season:

"Plans for offshore drilling activities are required to include a relief well drilling plan and an emergency countermeasure plan. The relief well drilling plan must identify suitable alternative drilling rigs and their locations; identify alternative relief well drilling sites; identify support equipment and supplies including, mud, casings and gravel supplies which could be used in an emergency; and specify the estimated time required to commence drilling and complete a relief well. The emergency countermeasures plan must identify the steps which will be taken to protect human life and minimize environmental damage in the event of loss of a drilling rig; ice override; or loss or disablement of support craft or other transportation systems." <sup>104</sup>

#### A. Primary Rig as Relief Well Rig

Shell proposes to drill a relief well first with the primary rig involved in the well blowout.<sup>105</sup> However, it is unlikely that the original drill rig would be able to move away and drill its own relief well in the event of a well control incident. The immediate use of a rig involved in a well blowout to drill a relief well is not consistent with industry safety standards nor federal pre-drill safety standards required by BOEMRE. Well control experts' standard procedures require the rig involved in a well blowout to be examined to assess the extent of damage sustained to the rig [e.g. by fire, erosion, hydrocarbon spills] before the rig should be used to safely drill a relief well. Illustratively, Shell's Beaufort and Chukchi Seas Regional Tactics Manual instructs personnel to immediately evacuate areas where hydrocarbon vapors exceed safe thresholds, shut-down ignition sources that could pose an explosion hazard, and to respond at a safe distance. Furthermore, we are not aware of any major blowouts in history where a drill ship involved in a blowout drilled its own relief well. In contrast, history shows that

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<sup>103</sup> 30 C.F.R. § 250.106(c).

<sup>104</sup> NSBMC § 19.70.050(1)(6).

<sup>105</sup> EP at 2-5.

when BOPs fail, rig evacuations are triggered and the original rig is unable to drill the needed relief well as in every one of the following cases:

- In 2010, the BP Macondo GOM well blowout, 11 people were killed and all others were immediately evacuated. The Deepwater Horizon semi-submersible drill rig was consumed by fire and sunk within days.<sup>106</sup>
- In 2009, the Australia Montara Platform well blowout resulted in immediate evacuation of all personnel on the West Atlas jack-up rig. The rig was eventually consumed in a fire.<sup>107</sup>
- In 2004, the GSF Adriatic IV jack-up rig operating in the Mediterranean Sea, offshore Egypt had a gas blowout igniting and sinking the rig.<sup>108</sup>
- In 2001, the Ensco 51 jack-up rig in the Gulf of Mexico lost well control. Hydrocarbons returning via the muds system posed an explosion hazard and personnel were immediately evacuated. A fire broke out destroying the derrick and substructure.<sup>109</sup>
- In 1998, the ODECO Ocean Odyssey semi-submersible drill rig lost well control and got substantial gas in the mud return at the drilling rotary table.<sup>110</sup> All personnel were immediately evacuated, except one person who died after being ordered to remain on the rig to carryout continued operations.<sup>111</sup>
- In 1985, the West Vanguard semi-submersible rig blowout, one person was killed and all others were immediately evacuated, the rigs deck structure and engine room was damaged in the blast leaving the rig listing 10 degrees.<sup>112</sup>
- In 1981, the Petromar V Drillship drilling in South China Sea suffered an uncontrolled sub-sea blowout which eventually caused the drillship to capsize.<sup>113</sup>
- In 1980, the Sea Quest semi-submersible rig blowout, all personnel were immediately evacuated, and the well caught fire and the rig was extensively damaged.<sup>114</sup>

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<sup>106</sup> BP Macondo Well Blowout, Gulf of Mexico (GOM), New Releases (Apr.-May 2010).

<sup>107</sup> PTTEP Australasia (Ashmore Cartier) Pty Ltd. (PTTEP), Montara Platform Blowout, New Releases (Aug.–Oct. 2009).

<sup>108</sup> Adriatic IV (Aug. 2004) [http://home.versatel.nl/the\\_sims/rig/adriatic4.htm](http://home.versatel.nl/the_sims/rig/adriatic4.htm).

<sup>109</sup> MMS 2001-08 Investigation; Ensco (Mar. 2001) [http://home.versatel.nl/the\\_sims/rig/ensco51.htm](http://home.versatel.nl/the_sims/rig/ensco51.htm).

<sup>110</sup> Ocean Odyssey (Sept. 1988) [http://home.versatel.nl/the\\_sims/rig/o-odyssey.htm](http://home.versatel.nl/the_sims/rig/o-odyssey.htm).

<sup>111</sup> FR.D. Ireland. Ocean Odyssey Fatal Accident Inquiry, Aberdeen Sheriff Court (1991).1991.

<sup>112</sup> <http://www.oilrigdisasters.co.uk/><sup>112</sup> Oil Rig Disasters,<sup>112</sup> <http://www.oilrigdisasters.co.uk/>.

<sup>113</sup> Petromar V, (Aug. 1981)<sup>113</sup> [http://home.versatel.nl/the\\_sims/rig/petromar5.htm](http://home.versatel.nl/the_sims/rig/petromar5.htm).

If the original rig is able to drill a relief well, certainly this option should remain open. But it seems unlikely that this will be possible. At a minimum, the limitations associated with this response option should be acknowledged in the planning process.

## B. Rig Availability

Shell's 2011 ODPCP states "it is Shell's expectation that this second rig will be in Alaska while exploratory drilling is underway in previously un-penetrated hydrocarbon formations below the surface casing point."<sup>115</sup> This language fails to demonstrate that Shell has planned and is prepared, as required by 30 C.F.R. § 250.202, to respond to a well blowout or loss or disability of a drilling unit, as required by 30 C.F.R. §§ 250.220.

First, the ODPCP should commit to more than an "expectation" to have a second drilling unit available. More definite language should be used to demonstrate a reasonable planning and preparation for loss or disability of a drilling unit; Shell's ODPCP should make a real commitment in absolute terms to having the second drilling unit available.

Second, the relief well rigs should be available throughout the exploration program. The ODPCP's qualifiers limiting the time periods when the relief well rig will be available (only when Shell drills into a previously un-penetrated formation below the surface casing point) mean that the ODPCP does not satisfy the requirements of 30 C.F.R. §§ 250.202 (planned and prepared) and 250.220 (to respond). The "below the surface casing point" qualifier is inappropriate as it ignores risks of shallow gas blowouts that could occur above the surface casing point. The "previously un-penetrated hydrocarbon formation" qualifier is inappropriate as well. First, as discussed below, this term is vague and ignores the need for Shell to actually possess the appropriate formation information gained from previous operations. Second, information about a formation from previous drilling operations does not reduce the blowout risk to zero. For example, the 2009 Montara well blowout in Australia occurred on a well that had drilled into a zone that had been previously penetrated, but this did not eliminate the blowout that was caused by human error. These qualifiers on Shell's commitment to have a relief well rig available for exploration drilling operations should be removed from the ODPCP. Where there is any risk of a blowout or loss or disablement of a drilling unit, a relief well rig should be identified, available, and prepared to respond.

Third, the relief well rig should be located in the Alaskan Arctic, not just somewhere in Alaska or even Dutch Harbor, to reduce the impacts of any well blowout. As noted above, if the Discoverer is the primary drillship, Shell proposes to position the Kulluk in Dutch Harbor. Shell estimates it will take 18 days to transit from Dutch Harbor to Camden Bay, and that it would

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<sup>114</sup> <http://www.oilrigdisasters.co.uk/><sup>114</sup> Oil Rig Disasters, <sup>114</sup> <http://www.oilrigdisasters.co.uk/>.

<sup>115</sup> ODPCP at 1-27.

then take 20 days to drill a Sivulluq relief well and 25 days to drill a Torpedo relief well – for a total of 38 to 43 day response time.<sup>116</sup> Staging the Kulluk in the arctic could reduce transit time, and total time to complete a relief well, could be reduced by at least 10 days.

Shell estimates that highest blowout flowrate for the four wells proposed under this EP,<sup>117</sup> would be 9,468 bopd from the Torpedo H prospect. Reducing the Kulluk transit time by 10 days could reduce the overall oil spill volume by at least, 94,680 bbls (approximately 4 million gallons). To put this amount of oil spill reduction in perspective, a 4 million gallon reduction equates to about 1/3 of the total oil spilled during the Exxon Valdez Oil Spill. Reducing the relief well response time, could significantly reduce the total volume of oil spilled, and reduce the adverse impacts of a spill.

Reducing the relief well rig response time would be consistent with BOEMRE's, and Shell's, obligation to prevent damage to or waste of any natural resource, property, or the environment from industry operations on an OCS lease.<sup>118</sup> Staging the relief well rig in the Alaskan Arctic would be optimize Shell's plan and reduce the risk of "undue or serious harm or damage to marine, or coastal environment."<sup>119</sup> Therefore, NSB requests that BOEMRE require relief well rigs to be located in the Alaskan arctic to reduce response time.

If BOEMRE does not adopt NSB's recommendations regarding the relief well rig availability, then at a minimum, the above quoted language – "it is Shell's expectation that this second rig will be in Alaska while exploratory drilling is underway in previously un-penetrated hydrocarbon formations below the surface casing point"<sup>120</sup> – must be clarified. First, any reference to an expectation rather than definite planning should be removed. Second, "previously un-penetrated hydrocarbon formations" should be clarified because, as written, this language could refer to formations penetrated by Shell or another operator. Because there

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<sup>116</sup> EP at 2-5 to 2-6 (The *Kulluk* or *Discoverer* will serve as its own primary relief well drilling vessel in the unlikely event of a well blowout. In the event that the primary relief well drilling vessel cannot be used, the secondary relief well drilling vessel will be mobilized. If the *Kulluk* is drilling the well at the time of a blowout, it is estimated that the *Discoverer* will be available to be on-site within 9 days (Table 2.g-2). If the *Discoverer* is drilling the well at the time of the blowout, it is estimated that the *Kulluk* will be onsite in 18 days. ... Once onsite, the *Kulluk* or *Discoverer* can drill a relief well for either the Sivulliq G or N well in 20 days and the Torpedo H or J well in 25 days. For the *Kulluk* as secondary relief well drilling vessel, total time from the blowout to completing the relief well is estimated to be 38 days for the Sivulliq wells and 43 days for the Torpedo wells. For the *Discoverer* as secondary relief well drilling vessel, total time from the blowout to completing the relief well is estimated to be 29 days for the Sivulliq wells and 34 days for the Torpedo wells)

<sup>117</sup> Sivulliq G. & Sivulliq N., Torpedo H and Torpedo J.

<sup>118</sup> 30 C.F.R. § 250.106(c) ("The Director will regulate all operations under a lease ... to: ... (c) prevent damage to or waste of any natural resource, property, or the environment."); 30 C.F.R. §250.232 ("What actions will MMS take after the EP is deemed submitted? (b) MMS compliance review. The Regional Supervisor will review the exploration activities described in your proposed EP to ensure that they conform to the performance standards in §250.202."); 30 C.F.R. § 250.202 (excerpted above).

<sup>119</sup> 30 C.F.R. § 250.202.

<sup>120</sup> ODPCP at 1-27.

is existing information about previously penetrated formations, the risk of a blowout due to unanticipated conditions may be reduced, but only if the operator actually has this existing information. And, it is not clear from this language that Shell would in fact have the formation information. Third, this sentence should be clarified to indicate whether the relief well rig will be available for all operations below the surface casing point for a well that will, at some point, encounter previously un-penetrated hydrocarbon formations. As written, this language indicates that the second rig might only be available when a new zone is penetrated and not during operations in other shallower sections of the well. Fourth, the ODPCP should identify the probable staging locations for the second drilling unit more precisely than just “in Alaska”, as the rig’s location will affect response times. Thus, at a minimum, if other recommendations relating to this section are not adopted, this language should be clarified to state (1) that relief well rig will definitely be available, (2) that Shell actually possesses the information gained from previous penetration of the formation, (3) precisely when relief well rigs will be available during operations, and (4) probable staging locations (identified as Dutch Harbor —if not changed – for the Chukchi Sea lease blocks).

#### C. Discoverer’s Ice Class

Shell’s relief well plan fails to demonstrate the company is planned and prepared to perform relief well operations because the plan does not demonstrate that the Discoverer a suitable rig for drilling a late season relief well in the arctic. Shell reports that the Discoverer’s hull has been “reinforced for ice resistance,” and that the drillship is rated to operate in 1.5 feet of ice.<sup>121</sup> But, Shell does not correlate this to anticipated ice thickness in Camden Bay up to October 31, or during November-December, when a relief well may be necessary.

Shell’s Well Control Plan does recognize that “extreme ice management efforts” may be required for relief well operations.<sup>122</sup> The plan does not discuss those efforts in detail, however, and also fails to address whether relief well drilling equipment, including the Discoverer, could safely operate in those conditions requiring “extreme ice management.” Use of drilling equipment that is not capable of operating in the sort of ice conditions that might be encountered poses an unreasonable risk of continued pollution and inability to abate the well blowout.<sup>123</sup>

#### D. Mudline Cellar

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<sup>121</sup> EP at 1-151-15.

<sup>122</sup> EP, Appendix A.

<sup>123</sup> 30 C.F.R. § 250.300 Pollution Prevention (a) During the exploration, development, production, and transportation of oil and gas or sulphur, the lessee shall take measures to prevent unauthorized discharge of pollutants into the offshore waters. The lessee shall not create conditions that will pose unreasonable risk to public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

Shell's relief well plan does not include construction of a mudline cellar (MLC), which Shell recognizes is important to protect wellhead equipment from ice.<sup>124</sup> The drill site locations at the Sivulliq and Torpedo prospects are within water depths where the seafloor is subject to extensive ice gouging and ice keel scouring.<sup>125</sup> The maximum gouge depth is estimated to be 8.2 ft (2.5 m) and the median width is 33 ft (10 m).<sup>126</sup> Especially in a late season relief well operation, which would carry into November or December, it is possible that the relief well BOP would need to be left in place and consequently exposed to ice gouging and ice keel scouring.

Shell does state that MLCs are required by law, important, and "only requires a few days to construct."<sup>127</sup> The EP recognizes that "MLCs are required by regulation everywhere in the Beaufort Sea OCS to protect wellhead equipment from ice, if and when the drilling vessel moves off the drill site."<sup>128</sup> And Shell notes that MLCs are especially important for wells that will be drilled or suspended over the winter, because MLCs are designed to protect well control equipment (wellhead casing and BOP) from potential ice gouge events over the winter.<sup>129</sup>

BOEMRE should examine whether it is safe, reliable and BAST to drill a relief well without a MLC and explain its rationale in its EP decision. Shell's relief well plan should explain why the relief well would be exempt from regulatory requirements and how the operations would be safe without a MLC. Alternatively, Shell should modify the EP to include MLC construction, including estimation of the time required to complete a relief well.

#### E. Estimate of Relief Well Completion Timing

Shell states that relief wells can be completed much quicker than wells drilled during routine operations. For routine operations, Shell estimates that a well drilled at a Torpedo Prospect will require approximately 44 days<sup>130</sup> and a well drilled at a Sivulliq prospect will require approximately 34 days.<sup>131</sup> For relief well operations, however, Shell estimates only 25 days would be required to drill a well at a Torpedo prospect, and only 20 days would be required to drill a well at a Sivulliq prospect.<sup>132</sup> BOEMRE should question Shell's assumption that its relief well can be drilled quicker than the initial well.

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<sup>124</sup> EP, Appendix L, at 2.

<sup>125</sup> EP at 5-4.

<sup>126</sup> EP at 15-2.

<sup>127</sup> EP at 7-1.

<sup>128</sup> EP at 15-26.

<sup>129</sup> EP at 2-4.

<sup>130</sup> EP, Appendix A, at 9 (Shell estimates a Torpedo well to take 44 days).

<sup>131</sup> EP, Appendix A, at 5 (Shell estimates a Torpedo well to take 44 days).

<sup>132</sup> EP at 2-6.

Relief wells usually take longer than an initial well for a number of reasons. Shell's well control expert, Wild Well Control recognizes that relief wells will take longer than the blowout well, and identifies a number of contributing factors:

- A directional well will result in greater depths and possibly additional casing strings;
- Additional drilling time because of the need to control direction and position of the wellbore;
- Additional drilling time because of ranging runs with equipment designed to home in on the blowout well at the proper depth;
- Potential drilling problems because of formations, which might be over-pressured by a blowout well;
- The relief well might become an additional or independent exploration well (different fault block) with the same, differing or more problematic issues than the designated exploration well, therefore, essentially doubling the risks for well control issue.<sup>133</sup>

Additionally, in a late season well blowout, there will be longer periods of darkness, limiting the amount of time well control operations can be conducted each day. Shell's EP and ODPCP assume that relief well drilling operations can run around-the-clock; however, most experts recommend relief well operations to be completed only during daylight hours for personnel safety. For example, in the 2009 Australia Timor Sea Montara Well Blowout, ALERT Well Control experts only allowed relief well operations during daylight hours due to safety concerns. ALERT Well Control experts have over 25 years experience on 1200 well control and industrial fire incidents. Shell's assumption that round-the-clock relief well drilling can occur is unrealistic.

A more realistic timeframe to complete a relief well is around 60 days. 62 days would account for 44 days to drill a Torpedo well and to 18 days to mobilize the Kulluk to Camden Bay.<sup>134</sup> A 60 day relief well timing estimate is also more consistent with estimates by operators drilling in the shallow marine waters of the Canadian Beaufort.<sup>135</sup>

## **XV. Arctic Well Capping and Containment System**

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<sup>133</sup> Wild Well Control, Same Season Relief Well Capability Review, at 18 (March 2010) (WWC's report, submitted to the Canadian Government, addressed a relief well plan for operations by Imperial Oil in the Canadian Beaufort. Notably, this same report identified "the length of the drilling season" as a challenge to completing same season relief wells in the Beaufort Sea.)

<sup>134</sup> Of course, as discussed elsewhere, if the Kulluk were staged in the Alaskan arctic, the transit time could be reduced substantially.

<sup>135</sup> See, Chevron presentation by Bill Scott at US DOE/Norway Arctic Workshop (January 2009); Canada National Energy Board Arctic Drilling Review, Review: <https://www.neb-one.gc.ca>.

Shell describes the proposed Arctic Well Capping and Containment System as a combination of a subsea capping stack, positioned on, and deployed from, an ice management vessel, and surface separation equipment on a containment vessel.<sup>136</sup> Shell states that the “containment system will be designed for conditions found in the Arctic including ice and cold temperatures.” And Shell emphasizes the intended flexibility of the system, “This equipment will also be designed for maximum reliability, ease of operation, flexibility and robustness so it could be used for a variety of blowout situations.”<sup>137</sup> Yet, Shell has not built or tested this equipment. Therefore Shell’s promises and assurances of this new technology will work in the arctic have not been verified by Shell or BOEMRE at this time.

a. New Technology

OSCLA regulations require a description of new or unusual technology used to carry out exploration activities accompany the EP.<sup>138</sup> BOEMRE defines new technology as equipment that has not been used previously or extensively in an MMS OCS Region or used previously under the anticipated operating conditions.<sup>139</sup>

Shell’s EP denies use of any new technology.<sup>140</sup> But Shell’s proposed Arctic Well Capping and Containment System, discussed elsewhere in the EP, is clearly new technology that has not been built, tested or used in the Alaska Arctic OCS, or in any other arctic location and thus meets the regulatory definition of “new or unusual technology.” In fact, although the EP describes the use of the Arctic Well Capping and Containment System for proposed 2012 operations, Shell recently described well capping technology as “not available.”<sup>141</sup> The Arctic Well Capping and Containment System is new technology and Shell should modify Section 2 of the EP to include the required description and discussion.

While the system has been described in general terms, there is very little design information or technical specifications offered in order for us to understand what equipment will be used or how the system will be constructed. The description required for new technology under OCSLA regulations should be added to the EP.

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<sup>136</sup> EP at 9-4; EP, Appendix A.

<sup>137</sup> EP at 12-4.

<sup>138</sup> 30 C.F.R. § 250.213(d) (The following general information must accompany your EP: ... (d) New or unusual technology. A description and discussion of any new or unusual technology (see definition under §250.200) you will use to carry out your proposed exploration activities.”); 30 C.F.R. §250.200 (“New or unusual technology means equipment or procedures that: (1) Have not been used previously or extensively in an MMS OCS Region; (2) Have not been used previously under the anticipated operating conditions; or (3) Have operating characteristics that are outside the performance parameters established by this part.”).

<sup>139</sup> 30 C.F.R. §CFR 250.200.

<sup>140</sup> EP at 2-4 (“There is no new or unusual technology proposed.”)

<sup>141</sup> April 2009 and January 2010 ODPCP, Rev 1 at Table 4-1. (“Equipment is not available for wells drilled from moored vessels. Proven [well capping] technology is not available or effective.”) This language also survived into the 2011 ODPCP under review.

## b. Evaluation

NSB supports the construction of new well capping and containment systems for the arctic; however, because this system is new technology, it must be thoroughly evaluated. Our November 29, 2010 letter to BOEMRE requested that BOEMRE verify that the capping and containment system will actually work in arctic conditions before relying on it in BOEMRE's approval (Attachment No. 3). We reiterate our request for a thorough technical review and an independent expert assessment completed to verify that Shell's proposed subsea capping system is proven and effective for Camden Bay drilling operations, including in late season weather conditions.

BOEMRE's inspection and evaluation of the equipment is especially important because Shell has expressed reservations regarding the feasibility of the system. In previous ODPCPs, Shell stated that subsea well capping systems were not technically feasible options.<sup>142</sup> Now, Shell's May 2011 ODPCP proposes use of a subsea well capping system;<sup>143</sup> but ruling the system out as best available technology, the same document states: "Well capping is not feasible for offshore wells from moored vessels with BOPE sitting below the mud line in a well cellar (glory hole)."<sup>144</sup> Shell's proposal to use well capping technology that the company simultaneously states is not feasible and is not best available technology is confusing.

BOEMRE should evaluate Shell's Arctic Well Capping and Containment System and verify that it will actually function as intended. The National Commission on the Deepwater Horizon Oil Spill recommended that: "The Department of the Interior should require offshore operators to provide detailed plans for source control as part of their oil spill response plans and applications for permits to drill...These plans should demonstrate that an operator's containment technology is immediately deployable and effective."<sup>145</sup> And, NTL 2010-N10 states that BOEMRE "will evaluate whether each operator has submitted adequate information demonstrating that it has access to and can deploy surface and subsea containment resources that would be adequate to promptly respond to a blowout or other loss of well control." The

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<sup>142</sup> April 2009 and January 2010 ODPCP, Rev 1 at 4-3 ("Well capping is **not feasible** for offshore wells from moored vessels with BOPE sitting below the mud line in a well cellar (glory hole); and killing a well by relief well drilling can take significantly longer to implement, increasing the duration of discharge. Given the **uncertainties** of the success of implementing surface control measures in these situations, relief well drilling mobilization efforts will begin immediately upon the incident escalating to a blowout.") (emphasis added).

- <sup>143</sup> ODPCP Section 1, Response Action Plan at 1-25 ("A set of subsea devices are assembled to provide direct surface intervention capability with the following priorities: Attaching a device or series of devices to the well to affect a seal capable of withstanding the maximum anticipated wellhead pressure (MAWP) and closing the assembly to completely seal the well against further flows (commonly called 'capping an .
- Attaching a device or series of devices to the well and diverting flow to surface vessel(s) equipped for separation and disposal of hydrocarbons (commonly called 'capping and diverting'").

<sup>144</sup> ODPCP, Section 4, at 4-3.

<sup>145</sup> National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling, at 23 (2011).

type of information in the oil spill response plans that BOEMRE “will evaluate includes ... subsea containment and capture equipment, including containment domes and capping stacks, ... capture vessels, support vessels, [and] storage facilities.” BOEMRE should include Shell’s Arctic Well Capping and Containment System in this evaluation and determine whether it is an effective response tool.

Shell has provided very little information on the technical specifications and design for this new system. There are a number of missing pieces of information that BOEMRE will need to determine if this system will be safe and effective in controlling a well blowout in arctic conditions, including:

- Engineering drawings for the proposed arctic well capping and containment system;
- Technical specifications for the arctic well containment system, including a description of the system components, capabilities, ratings and throughput capacity and a comparison to the worst case blowout conditions that may be encountered in a Camden Bay well blowout;
- A description of the arctic-specific design changes made to conventional well capping and containment systems, as compared to the environmental and physical conditions that will be encountered during the blowout;
- A explanation of why Shell previously determined well capping to be infeasible and the circumstances that have changed that now led Shell to propose well capping;
- Information on system design to prevent hydrate formation;<sup>146</sup>
- The containment system vessel’s ice class rating to operate in late season ice conditions, including supporting documentation from the certification society (e.g. ABS or DNV) verifying the ice class rating;
- An explanation of the containment system vessel’s station-keeping ability to remain over the blowout, addressing reduced buoyancy and encroaching ice;
- A comparison of the containment system vessel’s ice class rating to the ice conditions expected during the proposed drilling operations and the ice conditions that may be encountered drilling a late season relief well;
- Construction and testing timeline and how that correlates to Shell’s proposed 2012 drilling plans;
- A description of how the proposed system will comply with NTL 2010-N10;

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<sup>146</sup> Wild Well Control (WWC), Same Season Relief Well Capability Review, March 2010 states that the presence of hydrates can greatly hinder well control operations and that hydrate problems cannot be ignored and might become a major factor in well control. WWC recommends that Arctic BOP stacks be designed with glycol and methanol injection ports on the wellhead, BOP stacks and choke manifold and that non-aqueous fluids (NAF) be used in drilling to avoid the formation of hydrates.

- A timeline describing the time required to deploy this equipment; and
- The training, qualifications and experience of the crew that will operate the containment system.

Also, Shell should explain how its newly proposed Arctic Well Capping and Containment System differs from its earlier commitment to BOEMRE to construct and pre-stage a containment dome<sup>147</sup> for immediate deployment.<sup>148</sup> Complete information and a thorough evaluation of this new technology is required before Shell can rely on the system to support an approval of their EP or APD.

#### c. Timing of Inspection

Construction of Shell's the Arctic Well Containment System is behind schedule. In January 2011, Shell announced that it would have the system fabricated by May 31, 2011, for crew training in June 2011 and field deployment in July 2011.<sup>149</sup> Shell now states that this work will not be completed in 2011, but will be complete in time for the 2012 drilling season (July 2012).

Shell offers BOEMRE the opportunity to inspect the new well capping and containment system before the 2012 drilling season.<sup>150</sup> We are concerned, however, that given the construction timeline, the inspection would not happen until immediately before operations commence. This plan does not provide sufficient assurance that the new system will actually work in the arctic and that the crew will be trained to use the equipment prior to Shell's request for EP and APD approval.

### **XVI. Additional Challenges for Well Control Emergency Planning in Camden Bay**

There are a number of additional challenges and risks to well control emergencies in the Beaufort Sea that Shell does not fully address in the EP or ODPCP.

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<sup>147</sup> Shell's March 1, 2011 presentation to NSB and other stakeholders in Dutch Harbor stated that it was building a containment dome system to recover 25,000 barrels of oil per day (bopd). The system includes a subsea component and a surface vessel (barge). The containment dome would be deployed from the barge and latch onto a BOP using a remotely operated vehicle (ROV). The barge will have: heavy lift capability (800 tons); a large working deck area; processing equipment to separate oil, water and gas; and oil and gas flaring systems.

<sup>148</sup> Letter from Marvin E. Odum (President, Shell Oil Company) to S. Elizabeth Birnbaum (Minerals Management Service) at 5 (May 14, 2010).

<sup>149</sup> Alaska Offshore Special Report: Shell adds spill response capabilities, Company moves Kulluk to Dutch Harbor and moves forward with plans to build a well containment system for 2011 drilling season, Petroleum News, January 23, 2011.

<sup>150</sup> EP at 9-4.

First, there are additional risks of vessel sinking during a shallow water well blowout. Numerous well control experts agree that rigs and support vessel positioned over well blowouts in shallow water face additional risks of sinking because hydrocarbons, particularly gas, percolating from the subsea well blowout and reach the surface in a boil adversely impacting ship buoyancy.<sup>151</sup> Shell's well control consultant, Wild Well Control, noted this phenomenon makes it "difficult to get the drillship close enough to the wellbore to implement some sort of vertical intervention method."<sup>152</sup> Chevron's Canadian Beaufort Sea well control expert Bill Scott agrees that placing a rig over a well blowout in shallow marine waters, or placing a well capping/containment system over the blowout, can be risky because of the chance of the vessel sinking.<sup>153</sup> Shell has not addressed this risk in its EP or ODPCP.

Neither Shell's ODPCP or Well Control Plan<sup>154</sup> acknowledge the risk of drilling rig, well containment system, or rescue vessel capsize during a well blowout in shallow marine waters. Shell's Well Control Plan does not explain how it plans to position its well capping and containment vessel directly over the shallow water blowout and how it plans to address potential vessel buoyancy problems.

Second, there will be unique vessel station-keeping challenges in Camden Bay. Vessel station keeping in late season ice conditions is a major challenge for arctic operations.<sup>155</sup> In fact, for routine operations, Shell plans to move the drillship off the well during late season ice encroachment, acknowledging that ice conditions may exceed the capability of the station-keeping system.

But Shell's submissions do not explain plans for vessel station-keeping during well containment and fluid recovery operations. In fact, Shell's ODPCP discounts the potential vessel station-keeping challenges for its Arctic Well Capping and Containment System, stating that the system will be unaffected by ice or weather conditions at the surface.<sup>156</sup>

Vessel station-keeping plans for the containment vessel are needed. The containment vessel will need to stay in position over the well blowout. Because Shell proposes to operate until October 31, creating a risk of a well blowout control situation continuing in November to December, Shell needs to explain vessel station-keeping plans during encroaching ice

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<sup>151</sup> Blowout and Well Control Handbook, Grace (2003); Bill Scott, Chevron; Wild Well Control, Same Season Relief Well Capability Review (March 2010).

<sup>152</sup> Wild Well Control, Same Season Relief Well Capability Review (March 2010) (This document is a technical assessment for Imperial Oil as part of the Canadian National Energy Board Review of Arctic Well Control for the Beaufort Sea.)

<sup>153</sup> Personal communication between Susan Harvey, Harvey Consulting, LLC and Bill Scott, Chevron at the Arctic Engineering Conference in Houston Texas (2001).

<sup>154</sup> EP, Appendix L.

<sup>155</sup> Chevron Canada Limited, Canadian, National Energy Board Arctic Offshore Drilling Review AODR Submission Part 1: Briefing Document at 14 (April 2011).

<sup>156</sup> ODPCP at 1-31.

conditions that will be present in these months.<sup>157</sup> Or, Shell needs to explain how it plans to control the well blowout if the well containment system must move off location.

## **XVII. Need for Improved Arctic Spill Response Technology**

Most technologies used in responding to oil spills in sea ice have been adapted from those typically used on open water and land. Sea ice reduces the efficiency of all response methods.<sup>158</sup> The need to improve mechanical recovery capabilities in dynamic drift ice is cited repeatedly in published literature.<sup>159</sup> A 2004 report prepared for the Prince William Sound Oil Spill Recovery Institute and the US Arctic Research Commission identifies a need to “expand the operational capability of existing spill response equipment to enable oil recovery in ice.”<sup>160</sup> The same document indicates a “low” confidence in the ability to improve mechanical response in ice, noting “improvements likely to be incremental, resulting in modest increases in recovery effectiveness.”<sup>161</sup>

There is no proven technology to clean up an oil spill in icy conditions with the degree of efficacy described in Shell’s ODPCP, especially in fall-freeze up conditions with the currents and wave conditions found in the Arctic Ocean. Broken ice conditions limit spill response options. Fall freeze up conditions create the most challenging response conditions, where slush ice clogs skimmers and covers large areas of the sea, rendering mechanical response and in-situ burning infeasible.

## **XVIII. Environmentally Sensitive Areas and Areas of Public Concern**

Shell is required to demonstrate its ability to protect environmentally sensitive areas and areas of public concern during a spill.<sup>162</sup> The plan fails to make this demonstration for a summer oil spill or for a late season oil spill.

For example, Shell’s ODPCP contains 19 maps identifying priority protection areas from the Alaska Clean Seas (ACS) Technical Manual.<sup>163</sup> Protection of these identified important areas

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<sup>157</sup> COCP.

<sup>158</sup> Arctic Marine Assessment Programme (1998).

<sup>159</sup> Abdelnour, R. and Comfort, G. Application of Ice Booms for Oil Spill Cleanup in Ice Infested Waters. Fleet Technology Limited. Kanata, Ontario (April 2001); Dickins, D., and Buist, I., Countermeasures for Ice-Covered Waters. Pure Applied Chemistry Vol. 71, No. 1. pp. 173-191 (1999); Fingas, M. Weather Windows for Oil Spill Countermeasures. Report to Prince William Sound Regional Citizens’ Advisory Council (2004).

<sup>160</sup> Prince William Sound Oil Spill Recovery Institute and U.S. Arctic Research Commission (OSRI and ARC), Advancing Oil Spill Response in Ice Covered Waters (2004).

<sup>161</sup> Prince William Sound Oil Spill Recovery Institute and U.S. Arctic Research Commission (OSRI and ARC), Advancing Oil Spill Response in Ice Covered Waters (2004).

<sup>162</sup> 18 AAC § 75.425(e)(3)(J); And see, 30 C.F.R. § 250.106(c) (BOEMRE must regulate Shell’s operations “to prevent damage to or waste of any natural resource, property, or the environment.”)

<sup>163</sup> ODPCP at 1-29.

would require more than 78,000 feet of boom, along with shallow-draft vessels capable of operating in a range of arctic weather, sea-states, and ice conditions. However, for a 480,000 bbl WCD spill commencing on August 1, the ODPCP identifies only three task forces with six work boats to protect the nearshore and shoreline environment, with about 2,000 feet of boom. Shell's plan does not sufficiently illustrate an ability to protect the amount of shoreline and nearshore areas that could be impacted by a summer spill.

As discussed elsewhere in these comments, the ODPCP oil spill trajectories do not examine a worst case scenario, and do not accurately predict the amount or extent of nearshore and shoreline oiling. One product of the failure to adequately describe a worst case scenario is the assumption that: "shoreline exposures would not normally involve more than three or four high-priority protection sites at a time during the first 24 to 48 hours of a spill" and that "there would be time to deploy boom at sensitive sites, and to intercept the leading edge of the oil before it reaches the shoreline."<sup>164</sup> Thus, the ODPCP assumes that just a few nearshore and shoreline response teams can stay ahead of the spill's leading edge. And, while Shell offers that it might be "possible" to pre-stage equipment, this measure has not, as yet, been planned or carried out. However, because a WCD would carry greater quantities of oil to nearshore and shoreline areas, Shell ought to pre-stage response equipment to improve response capacity.

Further, the ODPCP does not explain how Shell can protect nearshore and shoreline areas, environmentally sensitive areas, or areas of public concern in a late season (late October) WCD scenario. Because Shell's EP requests authorization to operate in Camden Bay until October 31<sup>st</sup>, BOEMRE and Shell's planning must account for spill response needs and capacity for a well control event occurring at the end of October.

Shell's primary response action contractor for Beaufort Sea offshore, nearshore, and onshore spill response program is Alaska Clean Seas (ACS). Alaska Clean Seas Technical Manual states that offshore oil recovery with vessels drops to 50 percent effectiveness and boom capability drops to 20 percent in early October.<sup>165</sup> By November 1, Alaska Clean Seas Technical Manual shows that recovery with vessels and boom is impeded by ice 100 percent of the time. Furthermore, ACS's aluminum shallow draft vessels will all be taken out of the Beaufort Sea in early October because they cannot operate in late season ice conditions.<sup>166</sup> Shell's deeper draft vessels cannot operate in the nearshore shallow marine waters of the Beaufort Sea. Furthermore, contrary to statements in the ODPCP,<sup>167</sup> ACS does not own or operate ice-class

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<sup>164</sup> ODPCP at 1-35, 1-36.

<sup>165</sup> ACS, Technical Manual, Vol. 1, 2008, Tactics Descriptions at L-7.

<sup>166</sup> EP at 8-2.

<sup>167</sup> ODPCP at 1-54 ("Though unlikely, should a spill occur, Shell will have planned and implemented a nearshore and shoreline protection program with ACS, an Oil Spill Removal Organization with a proven record of performance involving dedicated personnel and best available technology. The activities of ACS will involve multiple, high

vessels and barges.<sup>168</sup> The ODPCP does not explain how Shell will provide nearshore spill response when its response team, ACC, is stranded onshore.<sup>169</sup>

Also, Shell acknowledges that when drifting ice is present, the use of boom is not feasible, and the company will not be able to provide any nearshore, shoreline, or wildlife protection even independent of ACS support.<sup>170</sup> Shell's strategy then resorts to monitoring oil as it interacts with drifting ice, and to hoping that where land-fast ice conditions are present, the natural ice barrier might afford some seasonal protection to sensitive shoreline resources. The ODPCP fails entirely to plan for nearshore response to a late season spill.

State of Alaska regulations require a that the ODPCP include "a description of the actions to be taken to contain and control the spilled oil, including, as applicable, boom deployment strategies, construction of temporary berms, and other methods"<sup>171</sup> and "an identification of which areas will be given priority attention if a discharge occurs."<sup>172</sup> A list and map of pre-staged equipment for protection of environmentally sensitive areas and areas of public concern (e.g. Native Allotments or subsistence use areas) would more fully demonstrate that Shell has planned and is prepared to meet these requirements.

## **XIX. Mechanical Recovery**

Shell's ODPCP recites an impossible mechanical recovery rate of 95%. Shell offers no support for this estimate. All experience and expert opinion indicates that in the best operating conditions the most optimistic mechanical recovery rate is 20%. Furthermore, the functionality of mechanical recovery methods is reduced in arctic conditions – especially later in Shell's proposed operating season, as daylight hours diminish and sea ice increases, but during summer conditions as well. Given the evidence of true mechanical recovery rates and the challenges to Arctic spill response, BOEMRE should require Shell to modify its ODPCP to reflect realistic recovery rate calculations appropriate for the arctic.

### **a. Mechanical Spill Response Generally**

Mechanical recovery of oil spills in open water or nearshore environments involves the physical containment of the oil within natural or man-made barriers and subsequent removal of oil from the water surface. Boom and skimmers are the primary components of mechanical

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volume elimination skimmers, ice-class vessels and barges, in a constant state of readiness to support Shell's offshore drilling." (emphasis added)).

<sup>168</sup> ACS North Slope Spill Response Equipment Catalog (2010).

<sup>169</sup> ODPCP at 1-35.

<sup>170</sup> ODPCP at 1-29.

<sup>171</sup> 18 AAC § 75.425 (e)(1)(F)(vi).

<sup>172</sup> 18 AAC § 75.425(e)(3)(J)(iii).

recovery. Booms are placed to contain spilled oil. Skimmers physically remove spilled oil from water after it is contained in sufficient concentrations by the boom. The efficiency of these tools depend upon the ability of the boom to physically contain the oil in sufficient concentrations, the rate at which skimmer comes into contact with pooled oil (encounter rate), and the maneuvering and repositioning time to place the skimmer for optimum recovery.<sup>173</sup>

Shell's ODPCP states that mechanical response with boom and skimmers can recover 95% of the worst case discharge oil spill.<sup>174</sup> To arrive at this recovery rate, Shell's ODPCP "assumes" that its offshore mechanical response task forces will be able to maintain a 90% recovery rate each day, and only 10% of the oil spill will bypass the offshore taskforces and enter nearshore marine waters.<sup>175</sup> Shell assumes that the nearshore task forces will recover half of oil that drifts into the nearshore areas and only 5% of the oil will contaminate the shoreline.<sup>176</sup>

This 95% recovery rate is unsupported by Shell and contrary to all evidence and expert opinion. Shell's ODPCP does not provide any evidence supporting this 95% recovery rate. Nor could NSB staff independently locate factual support of a 95% recovery rate. Rather, numerous authorities and examples support a conclusion that 95% mechanical response efficiency has never been achieved and is likely impossible, even under the calmest open water conditions with the best equipment and trained staff:

- BOEMRE has stated that mechanical containment and recovery in *open* water is generally 10-20%.<sup>177</sup>
- NOAA reports that mechanical response recovery rates rarely ever exceed 15-20%.<sup>178</sup> NOAA has previously cautioned BOEMRE that this is true even under the

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<sup>173</sup> Abdelnour, R. & Comfort, G. Application of Ice Booms for Oil Spill Cleanup in Ice Infested Waters. Fleet Technology Limited. Kanata, Ontario. (April 2001); Fingas, M., Weather Windows for Oil Spill Countermeasures. Report to Prince William Sound Regional Citizens' Advisory Council (2004).

<sup>174</sup> ODPCP at 1-33 (§ 1.6.7<sup>174</sup> Shell claims that Offshore Task Forces 1-3 and 5 will clean up 90% of the oil and the Nearshore Task Forces will collect 5%).

<sup>175</sup> ODPCP at 1-33. ("For planning purposes, the scenario assumes that 10 percent of the response volume ~~5,500 barrels of oil per day (bopd)~~ discharge escapes the primary offshore recovery efforts at the blowout.")

<sup>176</sup> ODPCP at 1-33. ("The ~~remaining volume of 550 bopd~~ discharged oil continues to drift to the west, driven by prevailing winds and currents. ACS skimming vessels with mini-barges, dispatched from Prudhoe Bay, intercept the oil as described in the scenario. For the purposes of the scenario, it is assumed that half of the oil encountered in the nearshore environment is not recovered, leaving half ~~about 275 bopd~~ to migrate to the shoreline.")

<sup>177</sup> Minerals Management Service, Alaska Outer Continental Shelf, Beaufort Sea Planning Area, Oil and Gas Lease Sales 186, 195, and 202, Final Environmental Impact Statement IV-17 (Feb. 2003) (Multi-Sale EIS), *available at* [http://alaska.boemre.gov/ref/EIS%20EA/2003\\_001.pdf](http://alaska.boemre.gov/ref/EIS%20EA/2003_001.pdf).

<sup>178</sup> Letter from Dr. Jane Lubchenco (Undersecretary of Commerce for Oceans and Atmosphere), to Ms. S. Elizabeth Birnbaum (Director, Minerals Management Service) (Sept. 21, 2009) at 6; International Tanker Owners Pollution Federation, Limitations of Containment and Recovery at 1, *available at* <http://www.itopf.com/spill-response/clean->

best of circumstances: “Recovery rates of spilled oil in optimum situations (calm weather, in a harbor, rapid response) rarely exceed 20 percent, and response to spills in ice in remote areas is substantially more challenge. On-scene response efforts may take days to weeks to implement, and are rarely effective.”<sup>179</sup>

- International Tanker Owners Pollution Federation, *Limitations of Containment and Recovery*, states that: “containment and recovery at sea rarely results in the removal of more than a relatively small proportion of a large [oil] spill, at best only 10 – 15 [percent] and often considerably less.”<sup>180</sup>
- Pew Environment Group prepared an expert review of arctic oil spill response capability and confirmed that in open water mechanical response is less than 20% in temperate water conditions, and is substantially less than that in arctic fall freeze-up conditions.<sup>181</sup>
- The mechanical response recovery rate for the Exxon Valdez was approximately 8%.<sup>182</sup>
- The mechanical skimming recovery system efforts during the Deepwater Horizon response only constituted 3% of the total amount of oil recovered.<sup>183</sup>

The poor mechanical response recovery rate for the Macondo well blowout highlighted flawed assumptions regarding the efficacy of mechanical recovery in federal response planning. These flawed assumptions were discussed at a May 2011 International Oil Spill Conference (IOSC) Workshop conducted by the USCG, BOEMRE and American Petroleum Institute (API).<sup>184</sup> The workshop described errors in the federal Effective Daily Recovery Capacity (ERDC) calculation used in OCS Exploration Plan ODPs.

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up-and-response/containment-and-recovery/ (“containment and recovery at sea rarely results in the removal of more than a relatively small proportion of a large [oil] spill, at best only 10 - 15% and often considerably less”).

<sup>179</sup> NOAA, Comments on Shell Camden Bay EP at 6 (2009).

<sup>180</sup> See International Tanker Owners Pollution Federation, *Limitations of Containment & Recovery*, available at <http://www.itopf.com/spill-response/clean-up-and-response/containment-and-recovery/>.

<sup>181</sup> Pew Environment Group, *Oil Spill Prevention and Response in the U.S. Arctic Ocean, Unexamined Risks, Unacceptable Consequences*, prepared by Nuka Research and Planning Group, LLC. (Nov. 2010).

<sup>182</sup> Wolfe, D.A., M.J. Hameedi, J.A. Galt, G. Watabayashi, J. Short, C. O’Clair, S. Rice, J. Michel, J.R. Payne, J. Braddock, S. Hanna, & D. Sale, *The fate of the oil spilled from the Exxon Valdez*. *Environmental Science and Technology* 28 (13): 561A-568A (1994).

<sup>183</sup> NOAA, *Deepwater Horizon Oil Budget* (Aug. 2010).

<sup>184</sup> International Oil Spill Conference (IOSC) Workshop, *Effective Daily Recovery Capacity (ERDC)* (May 2011); See, <http://www.iosc.org/>.

At this IOSC workshop, the USCG explained that the current ERDC calculation method overestimates oil spill recovery by mechanical response equipment in open water.<sup>185</sup> The USCG explained that BP estimated an ERDC of 162,000 barrels of oil per day (bopd) in the ODPCP for the Macondo well Exploration Plan. And, the equipment actually brought on site during the spill response had an ERDC of 492,000 bopd. So, based on the paper calculations this equipment should have been sufficient to clean up a 60,000 bopd oil spill. However, in reality, only 3% (1,800 bopd) of the 60,000 bopd was actually skimmed by mechanical response equipment at the sea surface in open water.<sup>186</sup> Even though 492,000 bopd of mechanical response skimming capacity was present at the spill scene, only 1,800 bopd was actually collected. The mechanical response to the Macondo subsea blowout was extremely inefficient.

During the same workshop BOEMRE agreed with USCG. BOEMRE explained that 30 C.F.R. §254.44 requires operators to de-rate the manufacturer's rated throughput capacity over a 24-hour period by 20 percent. The 20 percent reduction is meant to account for the limitations of the recovery operations due to available daylight, sea state, temperature, viscosity, and emulsification of the oil being recovered. USCG and BOEMRE both found this regulatory 20 percent de-rating factor was insufficient to predict the actual mechanical response capability that may be achieved for a subsea blowout.

While BOEMRE and USCG acknowledgments are refreshing, the persistence of admittedly inaccurate recovery rates in Shell's 2011 ODPCP suggests that "lessons learned" from the Deepwater Horizon oil spill have not been incorporated into OCS planning.

All available evidence and expert opinion, including BOEMRE's, suggests that the most optimistic recovery rate that can be expected, in ideal operating conditions, for mechanical recovery is 20 percent. Recovery rates will be less than that for the conditions that Shell proposed to operate in. Because Shell's 95 percent recovery rate estimate for mechanical response is unsupported and contrary to all evidence and expert opinion, including BOEMRE's, it should be corrected to reflect reality.

#### b. Mechanical Spill Response in the Arctic

Environmental factors, such as wind speed, sea state, visibility, safety considerations, and logistics further narrow the window of opportunity to contain, control, and recover oil spilled in the Arctic Ocean. The presence of sea ice affects the weathering and transport of spilled oil. Sea ice also complicates spill tracking, containment and recovery operations, and complicates logistical aspects of spill response. Cold weather conditions, including reduced visibility and reduced daylight hours later in the year reduce efficiency of both personnel and equipment.

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<sup>185</sup> International Oil Spill Conference (IOSC) Workshop, Effective Daily Recovery Capacity (ERDC) (May 2011).

<sup>186</sup> NOAA, Deepwater Horizon Oil Budget (Aug. 2010).

Sea ice, particularly dynamic drift ice, affects the functionality of both boom and skimmers, the primary components of mechanical recovery. Sea ice reduces the effectiveness of containment booms by interfering with the boom position, allowing oil to entrain or travel under the boom, or causing the boom to tear or separate. Sea ice also reduces a skimmer's efficiency to recover oil by lowering the encounter rate (rate at which skimmer comes into contact with pooled oil) and increasing the maneuvering and repositioning time to place the skimmer for optimum recovery among ice floes.<sup>187</sup>

Sea ice also complicates vessel operations and may limit or preclude the ability of some vessels to operate. Conventional marine operations in dynamic drift ice are vulnerable to rapid changes in weather and ice conditions. Significant down-time often occurs in conventional marine operations due to the movement of ice in response to wind conditions, with the sea state further impacting response efficiency.<sup>188</sup> Dynamic ice response trials on the Alaska North Slope in 2000 demonstrated significant problems with ice interference.<sup>189</sup>

Sea ice interaction with spilled oil complicates recovery efforts. Sea ice will impact the weathering and transport of spilled oil. Spilled oil can become trapped on top of, below, or within sea ice. The presence of dynamic drift ice interferes with the ability to contain oil with sufficient thickness to recover it. Oil tends to disperse and mix into the ice, making it necessary to separate the oil from the ice in order to clean up the spill.

Shell states that ice can often enhance spill response. While the OPDCP recognizes that "ice, even in low concentrations, can preclude the effective use of oil containment boom," Shell goes on to state: "when ice concentrations preclude the use of any boom, the ice will often serve as a natural barrier to the spread of oil and help concentrate the oil for pocket-recovery operations with stationary skimmers."<sup>190</sup> Of course, this helps only if spill response vessels are capable of operating in these more severe ice conditions. More information is needed to fully evaluate these statements.

As ice concentrations increase, the potential for the sea ice itself to contain spilled oil does increase – but this does not facilitate spill response. Even as the spreading rate is

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<sup>187</sup> Abdelnour, R. & Comfort, G. Application of Ice Booms for Oil Spill Cleanup in Ice Infested Waters. Fleet Technology Limited. Kanata, Ontario. (April 2001); Fingas, M., Weather Windows for Oil Spill Countermeasures. Report to Prince William Sound Regional Citizens' Advisory Council (2004).

<sup>188</sup> Dickens, D. & Buist, I., Countermeasures for Ice-Covered Waters. Pure Applied Chemistry Vol. 71, No. 1. pp. 173-191 (1999).

<sup>189</sup> Robertson, T. & DeCola, E., Joint Agency Evaluation of the Spring and Fall 2000 North Slope Broken Ice Exercises. Prepared for Alaska Department of Environmental Conservation, U.S. Department of the Interior Minerals Management Service, North Slope Borough, U.S. Coast Guard, and Alaska Department of Natural Resources. Anchorage, Alaska (2001).

<sup>190</sup> ODPCP at 3-21.

diminished, the recovery rate is severely impacted by the logistical inaccessibility of oil accumulations because of vessel, mechanical and human limitations. The limits of open water mechanical recovery systems in sea ice conditions have been correlated to the percent coverage of sea ice.<sup>191</sup> So the increasing ice concentrations ultimately are not very helpful to the recovery effort.

Depending upon a number of factors – including the exact ice, current, weather conditions and the availability of ice management vessels – containment systems lose functionality in 10 to 30 percent sea ice concentrations. Dickins and Buist found that most containment booms can be used in light brash ice conditions and ice concentrations up to about 30%.<sup>192</sup> Results from other tests and trials generally support the 30% rule, although dynamic drift ice conditions can significantly reduce recovery efficiency in ice conditions down to 10% coverage. During a series of equipment trials in dynamic ice on the North Slope in 2000, a barge-based mechanical recovery system proved somewhat effective in ice conditions up to 30%, but only if ice management systems were deployed to reduce the amount of ice present at the skimmer to 10% or lower. Sea ice caused considerable strain on containment booms and boom failure was a problem.<sup>193</sup> The trials demonstrated that the maximum operating limit for the barge-based mechanical recovery system in ice-infested waters was 0-1% in fall ice, 10% in spring ice without ice management, and 30% in spring ice conditions with extensive ice management.<sup>194</sup> BP's oil spill contingency plan for the Northstar facility in the Beaufort Sea supports a 10% operating limit, noting that at concentrations above 10%, the containment boom concentrates ice as well as oil, and the ice concentration proves problematic for recovery systems.<sup>195</sup>

Sea ice does not begin to provide “an effective means of reducing oil spill spreading” until concentrations of 60% or higher are present.<sup>196</sup> And, until there is approximately 70% ice concentration, additional containment is usually required to concentrate the oil so it can be recovered by a mechanical skimming device. But, as discussed above, those additional containment strategies are ineffective in ice concentrations above 10 to 30 percent.

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<sup>191</sup> DeCola, E., Robertson, T., Fletcher, S. & Harvey, S., Offshore Oil Spill Response in Dynamic Ice Conditions: A Report to WWF on Considerations for the Sakhalin II Project (2006).

<sup>192</sup> Dickins, D. & Buist, I., Countermeasures for Ice-Covered Waters. Pure Applied Chemistry Vol. 71, No. 1. pp. 173-191 (1999).

<sup>193</sup> Robertson, T. & DeCola, E., Joint Agency Evaluation of the Spring and Fall 2000 North Slope Broken Ice Exercises. Prepared for Alaska Department of Environmental Conservation, U.S. Department of the Interior Minerals Management Service, North Slope Borough, U.S. Coast Guard, and Alaska Department of Natural Resources. Anchorage, Alaska (2001).

<sup>194</sup> National Research Council (NRC), Board on Environmental Studies and Toxicology and Polar Research (BESTPR). Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope. The National Academies Press. Washington, DC. (2003).

<sup>195</sup> BP Exploration (Alaska), Inc., Northstar Oil Discharge Prevention and Contingency Plan (2003).

<sup>196</sup> Dickins, D. & Buist, I., Countermeasures for Ice-Covered Waters. Pure Applied Chemistry Vol. 71, No. 1. pp. 173-191 (1999).

Based on these estimates, ice conditions ranging from 30% to 70% coverage may present the biggest challenge to mechanical response, as conventional booms are likely to be ineffective, but ice conditions are not sufficient to afford natural containment of spills.<sup>197</sup> These are the ice conditions in which Shell proposes to operate.<sup>198</sup>

Aside from the challenge of containing oil spilled in ice-infested waters, recovery operations may also be complicated by the presence of ice. Most skimmers operate at a significantly reduced efficiency, or not at all, when drifting ice pieces are present within the oil slick. Some skimmers may be effective recovering oil between the cracks in ice leads, but quickly shut down as ice forms. Just positioning the skimmer in ice-free areas can be challenging.

Mechanical recovery operations in ice-infested waters are generally more effective on a small scale, such as collecting oil from small leads within ice floes using portable over-the-side skimmers or mobile units. Large-scale collection, such as that which is proposed by Shell have a very low efficiency. And, small batch mechanical recovery is limited in its ability to respond to a large spill. A report examining the challenges of mechanical recovery of a large oil spill from Shell's operations in Sakhalin Russia concludes that the scale of a response reliant on small batch mechanical recovery for a spill of 136 tonnes or more would be untenable.<sup>199</sup> The report notes, "the number of systems required to recover even 10% of the spill becomes unmanageable. There is little to be gained in these cases from bringing in more than a few vessels."<sup>200</sup>

NSB's concern regarding the functionality of mechanical spill response methods in icy waters is widely shared. Spill response experts agree that existing oil spill response technologies cannot effectively clean up a large scale oil spill to ice-infested waters.

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<sup>197</sup> Evers, Karl-Ulrich et al., *Oil Spill Contingency Planning in the Arctic—Recommendations*. Arctic Operational Platform (ARCOP) (2006); Glover, N. and Dickins, D., *Oil spill response preparedness in the Alaska Beaufort Sea*. Reprint of material presented in 1996 Symposium on Oil Spill Prevention and Response and 1999 International Oil Spill Conference (1999).

<sup>198</sup> ODPCP at 3-27 and 3-28.

<sup>199</sup> Dickins, D.F., *Oil spill behavior and oil spill response in ice conditions: a review*. Volume II: Technical and Operational Review of Offshore Oil-in-Ice Response Strategies. Background Paper Number 4.2, Sakhalin Energy Investment Company, Ltd (2005).

<sup>200</sup> Dickins, D.F., *Oil spill behavior and oil spill response in ice conditions: a review*. Volume II: Technical and Operational Review of Offshore Oil-in-Ice Response Strategies. Background Paper Number 4.2, Sakhalin Energy Investment Company, Ltd (2005).

- “No current cleanup methods remove more than a small fraction of oil spilled in marine waters, especially in the presence of broken ice.”<sup>201</sup> – National Research Council
- “Today there is no proven response method for recovery of large-scale oil spills in ice-infested waters.”<sup>202</sup> – Evers
- “If oil is widely distributed throughout broken ice, no countermeasure methods might be practical.”<sup>203</sup> – Owens
- “Mechanical recovery is extremely difficult in ice-infested waters, and is not an effective response option for large scale oil spills above 30% ice coverage.”<sup>204</sup> – DeCola, Robertson, Fletcher, Harvey
- “Oil spilled in broken-ice cannot be cleaned up effectively, and it is expected that whales would not avoid oil-fouled waters.”<sup>205</sup> – National Research Council
- “In-situ burning has not been demonstrated in actual field tests to be effective in ice coverage above 30% or below 70%. Above 70% coverage, sea ice may provide natural containment, although the sea ice may transport oil great distances so that it is unavailable for response once spring break up occurs. At higher ice concentrations, significant logistical, technical, and safety challenges remain in tracking, accessing, and igniting the oil slicks and recovering burn residues.”<sup>206</sup> – DeCola, Robertson, Fletcher, Harvey
- “In some cases, safety concerns will necessitate the ‘monitor and wait’ approach rather than attempting a risky marine operation, which might also have a very limited chance of success.”<sup>207</sup> – Dickins

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<sup>201</sup> National Research Council (NRC). Oil in the Sea III: Inputs, Fates, and Effects. The National Academies Press. Washington, DC. (2003).

<sup>202</sup> Evers, Karl-Ulrich et al, Oil Spill Contingency Planning in the Arctic—Recommendations. Arctic Operational Platform (ARCOP) (2006).

<sup>203</sup> Owens, E.H., L.B. Solsberg, M.R. West and M. McGrath, Field Guide for Oil Spill Response in Arctic Waters. Prepared for Emergency Prevention, Preparedness, and Response Working Group, Arctic Council (1998).

<sup>204</sup> DeCola,E., Robertson, T, Fletcher, S., & Harvey, S., Offshore Oil Spill Response in Dynamic Ice Conditions: A Report to WWF on Considerations for the Sakhalin II Project (2006).

<sup>205</sup> National Research Council (NRC). Oil in the Sea III: Inputs, Fates, and Effects. The National Academies Press. Washington, DC. (2003).

<sup>206</sup> DeCola,E., Robertson, T, Fletcher, S. & Harvey, S., Offshore Oil Spill Response in Dynamic Ice Conditions: A Report to WWF on Considerations for the Sakhalin II Project (2006).

<sup>207</sup> Dickins, D.F., Oil spill behavior and oil spill response in ice conditions: a review. Volume II: Technical and Operational Review of Offshore Oil-in-Ice Response Strategies. Background Paper Number 4.2, Sakhalin Energy Investment Company, Ltd (2005).

- “Field tests of a barge-based containment and recovery system in the Alaska Beaufort Sea, determined the system was only function in trace or minimal ice conditions, despite the use of ice management and ice deflection measures.” and “with more than trace ice present, the system had to be idled, reconfigured or repaired for relatively long periods of time such that the response effectiveness was diminished to near zero.”<sup>208</sup> – SL Ross Environmental Research Ltd. and DF Dickins Associates LLC in Beaufort Knowledge Review (2010) reporting on the 2000 Beaufort Sea field trials. The 2000 Beaufort Sea field trials demonstrated that the maximum operating limit for the barge-based mechanical recovery system in ice-infested waters was 0-1% in fall ice, 10% in spring ice without ice management, and 30% in spring ice conditions with extensive ice management.<sup>209</sup>
- In 2001, ADEC, MMS, DNR, and NSB approved a Joint Agency Report that confirmed industry’s inability to meet the state response planning standard using mechanical response in broken ice conditions.<sup>210</sup>

The limits of mechanical response in arctic conditions are recognized by industry as well. The April 2011 Canadian National Energy Board inquiry into arctic safety and offshore drilling requirements in the Canadian Beaufort Sea shed light on industry knowledge on mechanical response limitations in the arctic, for example:

- Chevron reported a 10% recovery rate in arctic conditions of the Canadian Beaufort Sea;<sup>211</sup> and noted “oil spill response is demanding under any circumstances, and Arctic conditions impose additional challenges. Some notable Arctic response challenges related to the behavior of oil in ice and offshore

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<sup>208</sup> SL Ross Environmental Research Ltd., DF Dickins Associates LLC., Envision Planning Solutions Inc. 2010, Beaufort Sea Oil Spills State of Knowledge Review and Identification of Key Issues, Environmental Studies Research Funds Report No. 177 (Beaufort Knowledge Review) 29-30, *available at* <http://www.esrfunds.org/pdf/177.pdf>.

<sup>209</sup> Robertson, T. & DeCola, E., Joint Agency Evaluation of the Spring and Fall 2000 North Slope Broken Ice Exercises. Prepared for Alaska Department of Environmental Conservation, U.S. Department of the Interior Minerals Management Service, North Slope Borough, U.S. Coast Guard, and Alaska Department of Natural Resources. Anchorage, Alaska (2001).

<sup>210</sup> Robertson, T. & DeCola, E., Joint Agency Evaluation of the Spring and Fall 2000 North Slope Broken Ice Exercises, Prepared for Alaska Department of Environmental Conservation, U.S. Department of the Interior Minerals Management Service, North Slope Borough, U.S. Coast Guard, and Alaska Department of Natural Resources. Anchorage, Alaska (2001).

<sup>211</sup> Chevron Canada Limited National Energy Board Arctic Offshore Drilling Review AODR Submission Part 2: Responses to NEB Calls for Information 1 and 2 Calgary, Alberta, at 30 (April 2011).

operating conditions include the lack of immediate access to oil trapped in moving ice, and extended periods of darkness for a portion of the winter.”<sup>212</sup>

- ConocoPhillips reported that mechanical recovery would “mainly be used for Tier 1 minor spills (i.e., spills of about 50 bbl to 100 bbl) in and around the drilling location, but is not appropriate for very large Tier 3 spills.”<sup>213</sup> And that, “mechanical recovery equipment would be of limited use for a Tier 3 spill because of the logistical challenge of transferring, processing and storing the large quantities of recovered product. Other general limitations in using mechanical recovery equipment include: the deployment of booms in sea states greater than 1.5 m; the deployment of booms in ice concentrations of 1/10 to 3/10<sup>th</sup>; and the need to manage or process the ice so that the skimmer encounter rate is not adversely affected.”<sup>214</sup>
- Oil Spill Response Expert Dave Dickins noted that oil spilled in late season ice conditions would result in difficulty accessing oil trapped on or under ice, and low encounter rates and recovery volumes associated with using independent skimmers to access oil trapped within the ice leads, and significantly reduced effectiveness for conventional containment and recovery systems in any measurable ice concentration (over 10% coverage) and logistically and operating challenges in very cold temperatures and extended periods of darkness or twilight for much of the winter.<sup>215</sup>

Thus, the ERDC calculation shortcomings identified at the IOSC, and discussed above, are compounded in the arctic. The 20% de-rating required by 30 C.F.R. §254.44 only takes into account, reduced recovery due to available daylight, sea state, temperature, viscosity and emulsification; the national 20% de-rating factor does not address the reduced recovery rate due to arctic conditions. Arctic weather conditions, including high winds, fog and ice will severely reduce the encounter rate and efficacy of mechanical recovery methods even more than in open water conditions.<sup>216</sup> In the Beaufort Sea, where Shell proposes to operate winds and currents may rapidly drive oil into the shallow marine waters and along the coastline out of the reach of the deeper draft offshore task forces. And, even if the offshore task forces could

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<sup>212</sup> Chevron Canada Limited National Energy Board Arctic Offshore Drilling Review AODR Submission Part 2: Responses to NEB Calls for Information 1 and 2 Calgary, Alberta at 20 (April 2011).

<sup>213</sup> ConocoPhillips, Public Review of Arctic Safety and Environmental Offshore Drilling Requirements Submission for Call for Information No. 1 and No. 2, Canada National Energy Board Review at 7-6 (April 2011).

<sup>214</sup> ConocoPhillips, Public Review of Arctic Safety and Environmental Offshore Drilling Requirements Submission for Call for Information No. 1 and No. 2, Canada National Energy Board Review at 7-7 (April 2011).

<sup>215</sup> Dickins, D.F., Behavior of Oil Spills in Ice and Implications for Spill Response. Proceedings Arctic Technology Conference, Houston (2011).

<sup>216</sup> Pew Environment Group, Oil Spill Prevention and Response in the U.S. Arctic Ocean, Unexamined Risks, Unacceptable Consequences, prepared by Nuka Research and Planning Group, LLC., at Chapter 5 (Nov. 2010,).

reach the oil, Shell over-estimates the recovery efficiency and encounter rate that will be achieved in arctic conditions.

At a minimum, BOEMRE should require Shell to modify its ODPCP to reflect realistic recovery rate calculations appropriate for the arctic. BOEMRE has the authority to require Shell to verify the capability of its proposed response equipment if Shell has “claimed effective daily recovery capacity that is inconsistent with data otherwise available to [BOEMRE].”<sup>217</sup> BOEMRE has evidence from all of the above cited sources that the ERDC calculations submitted by Shell are incorrect.

## **XX. In-situ Burning (ISB)**

Shell relies substantially on in-situ burning (ISB) to remove spilled oil and asserts that this method can achieve 85 percent oil removal efficiency.<sup>218</sup> However, the ODPCP fails to demonstrate that ISB is a viable method for the type of oil at the Camden Bay prospects, nor does the ODPCP identify adequate ISB equipment<sup>219</sup> to achieve the 85% oil removal efficiency. Also, Shell does not present a workable ISB plan for late fall and early winter Arctic conditions. Furthermore, even assuming a successful ISB response, Shell fails to address significant safety and impact concerns.

### **a. Operational Requirements**

In-situ burning of spilled oil requires containment of spilled oil to an appropriate thickness, ignition of the oil slick, and recovery of burn residues. Oil containment for in-situ burning can be accomplished either with natural barriers (e.g. topographic features on land, snow berms, sea ice) or man-made booms. Fire boom used for in-situ burning must be constructed of fire-resistant materials. Once the slick is contained at an appropriate thickness for burning, an ignition source is required to initiate the burn. The minimum thickness required for the oil slick to ignite varies depending upon the temperature, the type of oil, the amount of emulsification and degree of weathering.

According to the US National Response Team, in-situ burning is considered to be a “viable response method” only if certain slick thickness and environmental parameters can be met:

- The oil slick must be thick enough to ignite (which is difficult to achieve in ice conditions up to 60% with mechanical booms);

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<sup>217</sup> 30 C.F.R. § 254.45(a)(3).

<sup>218</sup> ODPCP at 1-11; ODPCP at 3-23.

<sup>219</sup> ODPCP § 3.4.3

- Wind and wave conditions must be moderate (Arctic ocean natural hazards can produce extremely cold temperatures together with severe and sustained wind and wave conditions);
- The oil must not have significantly emulsified (oil leaking from a subsea blowout 100 feet deep, will be thoroughly emulsified); and
- The downwind emissions must be below threshold concentrations for sensitive populations (NSB residents and other industrial operations are downwind of Shell's proposed operations).<sup>220</sup>

b. Proven ISB recovery rates

Shell's claim of 85% oil removal efficiency is not supported by actual oil spill response experience on water. Only a 5% overall ISB removal rate was achieved in the Deepwater Horizon oil spill response.<sup>221</sup> In *Deepwater Horizon Oil Spill* response crews had access to the spilled oil, they were able to thicken the spilled oil using fire boom, and no ice hampered recovery operations. These response conditions will not be present in an arctic spill.

Furthermore, there is no historical record of a successful in-situ burn of emulsified 20°API crude oil ever being conducted in arctic conditions after it has percolated 100-120' through a seawater column from a subsea blowout. Shell's claim that this response tactic will be successful is unsubstantiated.

c. API

ISB efficacy depends on the characteristics of the oils to be burned. Oils with high API gravities (above 38°) tend to burn relatively easily, while those with API gravities below 20° burn only under "optimal conditions." For oils with API gravities in the range of 20° to 35°, the suitability of in-situ burning cannot be predicted solely on the basis of physical properties.<sup>222</sup> Sivulliq and Torpedo prospect oil is approximately 20° API.<sup>223</sup> Thus, this oil is unlikely to burn even if released at the surface without the added ignition challenges created by emulsification, spreading, or ice conditions.

d. Arctic Ice Conditions

The ODPCP and EP fail to demonstrate that ISB is a viable method in late fall and early winter arctic conditions. ISB has not been demonstrated in actual field tests to be effective in

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<sup>220</sup> National Response Team (NRT) Science and Technology Committee, Fact Sheet: Site Safety Plans for Marine In Situ Burning Operations. National Response Team Fact Sheet (1997).

<sup>221</sup> NOAA, Deepwater Horizon Oil Budget (Aug. 2010).

<sup>222</sup> McCourt, J., & Buist, I., Results of laboratory tests on the potential for using in situ burning on 17 crude oils. Proceedings of the 2001 International Oil Spill Conference. pp. 529-532 (2001).

<sup>223</sup> ODPCP at 1-64.

ice coverage above 30% or below 60-70%. Above 70% coverage, sea ice may provide natural containment, although the sea ice may transport oil great distances so that it is unavailable for response once spring break up occurs. At higher ice concentrations, significant logistical, technical, and safety challenges remain in tracking, accessing, and igniting oil slicks and recovering burn residues.<sup>224</sup>

At ice coverage up to about 60-70%, ISB generally requires the use of manmade fire booms to contain the oil to the required thickness. In ice conditions ranging from 30% to 60%, ISB operations would face many of the same constraints as mechanical recovery, because of the interference with containment booms. Boom-towing vessels must be able to maneuver and position booms to contain oil to the desired thickness. An ignition source must then be deployed from a vessel or aircraft. Ice conditions in the 30% to 60% range are considered to be the “most difficult from an in-situ burning perspective.”<sup>225</sup> In this range, natural containment by the ice is less likely and containment boom deployment is generally not possible. These are the very conditions that Shell plans to be operating in.

ConocoPhillips, with decades of experience operating in the arctic, explains that while ISB systems may work effectively in light drift ice conditions, “the limiting factor in higher ice concentrations being the ability of the fire boom to limit the amount of ice entering the boom, which could restrict the amount of oil being gathered.”<sup>226</sup> ConocoPhillips suggests: “options that might be used to increase the effectiveness of ISB in ice include: using ice leads as booming devices to restrict the spreading of the oil so sufficient thickness would be retained for ignition or using herding agents to contract the spreading oil so that a sufficient thickness would be retained for ignition.”<sup>227</sup> However, herding agents are not currently approved by EPA for use in any U.S. water, nor can Shell guarantee that sufficient oil will be trapped in ice leads to achieve anything close to a 85% burn efficiency.

#### e. Oil Thickness and Emulsification

According to the U.S. National Response Team, in-situ burning is considered to be a “viable response method” only if certain the oil slick is thick enough to ignite.<sup>228</sup> The minimum

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<sup>224</sup> DeCola, E., Robertson, T., Fletcher, S., & Harvey, S., Offshore Oil Spill Response in Dynamic Ice Conditions: A Report to WWF on Considerations for the Sakhalin II Project (2006).

<sup>225</sup> Evers, Karl-Ulrich et al., Oil Spill Contingency Planning in the Arctic—Recommendations. Arctic Operational Platform (ARCOP) (2006).

<sup>226</sup> ConocoPhillips, Public Review of Arctic Safety and Environmental Offshore Drilling Requirements Submission for Call for Information No. 1 and No. 2, Canada National Energy Board Review, at 7-5 (Apr. 2011).

<sup>227</sup> ConocoPhillips, Public Review of Arctic Safety and Environmental Offshore Drilling Requirements Submission for Call for Information No. 1 and No. 2, Canada National Energy Board Review, at 7-5 (April 2011).7-5.

<sup>228</sup> National Response Team (NRT) Science and Technology Committee, Fact Sheet: Site Safety Plans for Marine In Situ Burning Operations. National Response Team Fact Sheet (1997).

thickness required for an oil slick to ignite varies depending upon the temperature, the type of oil, the amount of emulsification and degree of weathering.

Generally, spilled oil must be at least 0.04"-0.13" (1-3mm) thick to sustain a burn,<sup>229</sup> but even at oil thicknesses of 1-3 mm, Shell estimates that burn efficiencies will drop to 50-60%.<sup>230</sup> In most cases un-boomed oil will not be thick enough to burn because oil slicks spread rapidly and are usually thin, less than 0.008"<sup>231</sup> (0.2mm). As discussed, containment of oil in required thickness is difficult in 30-60 percent sea ice conditions because of the reduced efficacy of boom and/or ice to contain spilled oil.

Because oil spilled from subsea well blowouts will be emulsified when it reaches the sea surface and is subject to wave action, a boom is required to thicken the oil to at least 0.2" (5mm) to sustain a burn.<sup>232</sup> Even then, Shell reports emulsified oil is very difficult to burn,<sup>233</sup> and that burn efficiency diminishes to zero when oil is more than 25% emulsified.<sup>234</sup> Shell states that within hours of reaching the surface oil will be so emulsified that ignition will be "difficult to impossible."<sup>235</sup>

#### f. Equipment Inventory and Training

Shell's ODPCP does not identify sufficient ISB equipment<sup>236</sup> to achieve the claimed 85% oil removal efficiency, especially in sea ice conditions.<sup>237</sup> Shell lists the local ISB resources of Alaska Clean Seas (ACS) and ASRC Energy Services (AES).<sup>238</sup> However, the resources of these response organizations are inadequate to respond to 480,000 bbl WCD in sea ice. And Shell does not identify any other national or international resources that the company will bring to bear to validate its claim of 85% oil removal efficiency. Furthermore, it is unclear how much training ACS and AES responders have had with equipment that is available.

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<sup>229</sup> ODPCP at 3-23.

<sup>230</sup> ODPCP at 3-24.

<sup>231</sup> MMS, Real-time Detection of Oil Slick Thickness Patterns with a Portable Multispectral Sensor, TAR Project 544 (2005).

<sup>232</sup> Fingas, M., Weather Windows for Oil Spill Countermeasures. Report to Prince William Sound Regional Citizens' Advisory Council (2004).

<sup>233</sup> ODPCP at 3-24 (states: "Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 to 80 percent range with some up to 90 percent. The oil in the emulsion cannot reach a temperature higher than 100 degrees Celsius (°C) until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used first, mostly to boil the water rather than heat the oil.").

<sup>234</sup> ODPCP at 3-24.

<sup>235</sup> ODPCP at 3-32.

<sup>236</sup> ODPCP § 3.4.3

<sup>237</sup> ODPCP at 3-23.

<sup>238</sup> ODPCP at 3-29.

Both ACS and AES have fire boom to contain spilled oil. However, this fire boom faces the same limitations as boom utilized for mechanical recovery – the efficacy of boom is limited if sea ice is present in concentrations greater than 10%. Furthermore, ACS and AES cannot deploy their boom in late fall or early winter ice conditions as neither organization has ice class vessels capable of operating in the nearshore waters of the Beaufort Sea.

The ability of ACS and AES to access and ignite contained oil is also questionable. ISB responders will need to launch gelled fuel starters to ignite contained oil. Most of the burns conducted during the *Deepwater Horizon* response were ignited from vessels, where personnel tossed gelled fuel from the vessel. However, in many circumstances, Arctic class vessels will be needed to adequately access spilled oil. As noted above, neither ACS nor AES has arctic class vessels.

Without arctic class vessels, ACS and AES responders will be limited to air access during the initial response to a spill in sea ice. And only ACS has Heli-Torch equipment to conduct burns from the air; AES does not.<sup>239</sup> Furthermore, because without arctic class vessels boom cannot be deployed in ice conditions, ACS will only be able to ignite oil using Heli-Torches suspended from helicopters if un-boomed oil is thick enough to burn.

ACS only has 6 Heli-Torches and 2 Heli-Torch gelled fuel mixers – minimal ISB inventory for offshore operations..<sup>240</sup> Shell has not provided any calculations to show the 85% burn rate could be achieved using just 6 Heli-Torches and 2 Heli-Torch gelled fuel mixers, taking into account the logistical and transportation delays of deploying this equipment in the weather conditions that would occur during a response to a late season WCD. ACS reports that each of its Heli-Torches only holds 55 gallons of fuel, which equates to about 5 minutes of burn time before the helicopter would have to return to the runway for refueling.<sup>241</sup>

It is unclear how much training ACS and AES responders have had with equipment that is available. Shell's ODPCP states that ACS conducts ISB training 7-8 times per year:

ACS conducts in-situ burn training seven to eight times a year at different North Slope locations. Typical courses involve at least one hour of classroom instruction and one hour of field exercises involving basic combustion theory, guidelines for safe operating procedures, and gelled fuel mixing and Heli-Torch deployment. Shell/AES personnel are also instructed on these same guidelines and procedures as they relate to the potential use of controlled burning offshore.<sup>242</sup>

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<sup>239</sup> ODPCP at 3-30.

<sup>240</sup> Alaska Clean Seas Equipment Inventory (2010).

<sup>241</sup> Alaska Clean Seas, Arctic Oil Spill Response Training Class (May 2011).

<sup>242</sup> ODPCP at 3-30.

However, ACS reports that it has not conducted live helicopter deployment drills with the Heli-Torch units for over five years, and its field experience has been limited to hand held ignitors used onshore to burn oil soaked tundra.<sup>243</sup>

#### g. Safety

Assuming Shell is able to ignite and burn 85% of 480,000bbl of spilled oil, there are significant safety concerns raised by Shell's ISB plan. Shell's oil spill trajectory shows spilled oil moving west from Camden Bay, entering the Prudhoe Bay area, surrounding existing nearshore oil and gas facilities such as Endicott, Northstar, Nikaitchuq and then Oooguruk.<sup>244</sup> If oil is not successfully burned before it reaches Endicott Island, the burn would occur next to existing Beaufort Sea oil and gas facilities. Once the spill is within some proximity of Endicott Island, it would not be safe to initiate the ISB until the oil passed a safe distance to the west of Oooguruk. By the time the spill passed Oooguruk, spilled oil would have already contaminated important subsistence use areas, Prudhoe Bay and entered the Colville River Delta.

#### h. ISB Impacts

A successful ISB would itself have detrimental effects on the environment and residents. ISB operations would generate significant air pollution and contribute to global warming impacts. Furthermore, there would be significant impacts to water quality and subsistence resources as burn residue sinks to the seabed floor. Additionally, burns on the surface of the sea will kill important marine species, because surface microlayer organisms are vulnerable to impacts from oil slicks and subsequent burning. The ocean surface microlayer, approximately the upper millimeter of the water surface, is an important ecological niche that provides habitat for many sensitive life stages of marine organisms. Eggs and larval stages of fish and crustaceans, and reproductive stages of other plants and animals develop in this layer, which often contains dense populations of microalgae with species compositions distinct from the phytoplankton in the layers below.<sup>245</sup>

#### i. Regulatory Standard

State regulations require Shell's ODPCP to demonstrate the efficiency and effectiveness of ISB and must include a full assessment of potential environmental consequences, provisions for continuous monitoring and real-time assessment of environmental effects.<sup>246</sup> Shell has not provided sufficient scientific data to demonstrate the efficacy of ISB in an offshore arctic marine

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<sup>243</sup> Alaska Clean Seas, Arctic Oil Spill Response Training Class, Portland IOSC (May 2011).

<sup>244</sup> ODPCP 1-83at 1-83.

<sup>245</sup> Shigenaka, G. & Barnea, N., Questions About In Situ Burning as an Open-Water Oil Spill Response Technique. National Oceanic and Atmospheric Administration. HAZMAT Report 93-3 (1993).

<sup>246</sup> 18 AAC 75.445

environment, responding to a subsea blowout in the weather conditions present during its planned seasons of operation and oil spill clean-up.<sup>247</sup> Nor has Shell examined the potential human health impact of large scale burning to onshore residents (e.g. Nuiqsut) or the people that live and work along the Beaufort Sea shoreline.

#### j. Summary

Shell asserts an 85% recovery rate of spilled oil by ISB response. But, the type of oil found in Camden Bay, approximately 20<sup>o</sup> API, will burn only under “optimal conditions.” Furthermore, spilled oil that is more than 25% emulsified has 0% burn efficiency, and Shell acknowledges that within hours of reaching the surface from a 100-120’ depth, spilled oil will be so emulsified that ignition will be “difficult to impossible.”<sup>248</sup> Efforts to contain and ignite the spill would be thwarted by 30-60% sea ice concentrations as ACS and AES do not have arctic response vessels and the ice would prevent containment and thickening of oil in ignitable concentrations while still being insufficient to provide natural containment. Shell fails to present information regarding historical ISB recovery rates in Arctic conditions to support their claimed recovery rate. And, finally, Shell’s submissions fail to address significant safety and environmental impact concerns.

### **XXI. Field Testing and Drills**

Shell has proposed oil spill response tactics in its ODPCP that have not been demonstrated to be effective in arctic Beaufort Sea ice conditions, nor has Shell demonstrated these tactics can achieve the recovery rates cited in the EP and ODPCP. Untested and unproven tactics should not be relied upon to demonstrate compliance with State of Alaska (18 AAC 75) and Federal (30 CFR 254) standards. Volunteer field testing by industry operators or operational drills required by BOEMRE would serve to verify or invalidate response tactics Shell relies upon in this EP and ODPCP.

Shell proposes some ISB and mechanical recovery operations, but as discussed elsewhere in these comments, the recovery rates are highly inflated, especially for fall freeze-up conditions. Existing field test data in Beaufort Sea fall freeze-up conditions demonstrates that in-situ burning and mechanical response are both limited to less than 10% recovery in slush ice conditions.<sup>249</sup> This leaves little or no response method until winter sets in and an on-ice response can be safely initiated. By this time, oil would have frozen into the ice, and

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<sup>247</sup> ODPCP at 3-23.

<sup>248</sup> ODPCP at 3-32.

<sup>249</sup> Robertson, T. & DeCola, E., Joint Agency Evaluation of the Spring and Fall 2000 North Slope Broken Ice Exercises, Prepared for Alaska Department of Environmental Conservation, U.S. Department of the Interior Minerals Management Service, North Slope Borough, U.S. Coast Guard, and Alaska Department of Natural Resources. Anchorage, Alaska (2001).

contaminated ice mining using civil engineering techniques and yellow-iron equipment would not be possible until ice conditions allow safe access.

MMS's own studies and reports verify these concerns. A 1998 MMS study<sup>250</sup> assessed spill response tactics and clean up capabilities for large blowouts in broken ice. This study concluded that mechanical recovery to a subsea blowout in fall freeze-up conditions was estimated at 0.6-5.9%, assuming that some mechanical response could be achieved above 30% ice conditions, which was later disproved in the year 2000 Beaufort Sea trials where mechanical response in fall slush ice conditions proved extremely challenging. A 2009 MMS report concluded that even trace amounts of ice (less than 1/10 ice coverage) can cause significantly reduced efficiencies in mechanical recovery."<sup>251</sup>

NSB's past comments on Shell's EP and ODPCP (2007-2010) questioned plans that relied on estimates and assumptions that MMS knew were questionable based on its own work.<sup>252</sup> NSB requests that BOEMRE carefully examine the cited information and ensure that its decision is consistent with its own technical and scientific work on oil spill response methods and recovery rates for the Beaufort Sea.

Given the available studies and field test data that suggests recovery systems are not effective in sea ice conditions in which Shell intends to operate, Shell should be required to provide affirmative evidence, field test data, that each oil spill response tactic described in its plan was field tested in arctic conditions. Shell should be required to verify that the recovery rates proposed can be achieved or amend their recovery rates to proven numbers.

Alternatively, or additionally, BOEMRE could exercise its authority to conduct unannounced drills to test the spill response preparedness of owners and operators.<sup>253</sup>

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<sup>250</sup> Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea During Periods of Broken Ice, Prepared by S.L. Ross Environmental Research Ltd, D.K. Dickins and Associated, Ltd. and Vaudry and Associates, Inc. for the U.S. Minerals Management Service and Alaska Clean Seas (June 1998).1998.

<sup>251</sup> MMS, Arctic Oil Spill Response Research and Development Program Report (2009).

<sup>252</sup> NSB has long held that "spill response should be anchored in provable cleanup technologies, and real-world demonstrations of cleanup capabilities should be required before activity begins."<sup>252</sup> Adequate spill response should include a demonstration of industry's ability to retrieve spilled oil in broken or refreezing ice conditions during the transitional periods of spring and autumn. Purposely spilling a small amount of oil in representative conditions is worth the risk of minor contamination in order to prove the true extent of industry's spill response readiness. Allowing OCS development without such a demonstration means we are accepting substantial risk on the basis of a wish and a promise. As national policy, this is fundamentally irresponsible. A phased approach to a real-world demonstration could start with a laboratory prototype as a first step. NSB, Arctic Offshore Policy Positions on Oil and Gas Development (Attachment No. 4).

<sup>253</sup> 30 C.F.R. § 254.42(g)-(h) (In the past BOEMRE/MMS has relied on small-scale laboratory tests to evaluate the efficacy of response systems. This approach is problematic for a number of reasons. Information gleaned from small-scale laboratory and tank does not examine the major inefficiency present in arctic response – the inability to effectively encounter oil. Additionally, small-scale laboratory and tank tests, based on a single piece of equipment or an individual technology does not guarantee that the entire response system required to deploy that

BOEMRE could require changes in response equipment, procedures, or strategies as a result of lessons learned during the drills. To verify that Shell has sufficient equipment and personnel to respond to an October 31 spill and to identify appropriate changes in the spill response plan, BOEMRE should exercise its authority to conduct a drill in Camden Bay. The drill should use Shell's planned oil spill response equipment, and occur prior to Shell's Exploration Program. The drills should be conducted in November and December ice and weather conditions to examine whether Shell's proposed oil spill response equipment would be capable of cleaning up oil<sup>254</sup> in those conditions.

BOEMRE should coordinate the drill program with other state and federal agencies, and include NSB representatives. NSB also requests that BOEMRE provide an explanation of the staff resources expertise and qualifications of personnel that will be assigned to conduct and evaluate these drills, including any independent experts that will be hired by BOEMRE to assist. Independent experts hired to assist BOEMRE should be truly "independent."

It is critical to test oil spill response capability prior to BOEMRE's approval of Shell's EP because previous oil spill response drills in the Beaufort Sea have shown major flaws in oil spill response capability in arctic conditions.

An Exploration Plan that fails to demonstrate that the operator is planned and prepared to respond to an oil spill is inconsistent with requirements that the EP include a response plan. Because available information suggests that Shell's response plan is inadequate for spills occurring in October, Shell should be required to affirmatively verify its response plan through real world response drills. These drills should be conducted prior to BOEMRE's decision on the EP, or at a minimum satisfactory completion be made a condition of BOEMRE's EP approval. Unless the response tactics and recovery rates can be verified through drills and field tests, Shell's EP should be modified to (1) reflect more accurate recovery rates and (2) conduct activities only during seasons where response tactics are relatively effective.

## **XXII. Winter Oil Spill Response Scenario**

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technique will have the same functionality. For example, a tank test demonstrating that a skimmer will not clog until ice concentrations exceed 40 percent coverage does not mean that the full oil spill recovery system—vessels, boom, skimmer and storage barge—could operate safely or effectively up to that limit. Typically there is one or two weak links in the response systems that will reduce the efficiency of the entire system. For example, Shell may have a skimmer that has a high pump rate, but that is of little benefit if that skimmer cannot encounter the oil because the boom or ACS's aluminum bay class boats cannot withstand the ice conditions, or the oily waste collection hose clogs with ice. Real world drills and exercises are better for identifying problems in the response system).

<sup>254</sup> Because EPA will not allow Shell to intentionally spill oil to test equipment efficacy, Shell should identify alternative non-toxic materials to be used as a surrogate for demonstrating oil spill response efficacy.

Shell plans to operate until October 31, which could result in an oil spill of 480,000 bbls into the Beaufort Sea, requiring oil spill response to commence November 1 and continuing throughout the winter. Shell does not include a winter oil spill response scenario the ODPCP. Shell should be required to include a winter oil spill response scenario in its ODPCP or revise its ODPCP and EP to limit operations to the July- August timeframe, to allow time to cleanup oil in summer conditions.

Because oil spilled from Shell's OCS leases may impact state waters, Shell must demonstrate that it meets both State of Alaska (18 AAC 75) and Federal (30 CFR 254) oil spill prevention and response planning requirements. Shell is required by State of Alaska regulation to include a response scenario that demonstrates its ability to respond to the worst-case scenario<sup>255</sup> in the worst-case timeframe it could occur.<sup>256</sup> Additionally, the State of Alaska requires exploration operations to demonstrate that it can contain, control and cleanup a well blowout within 15 days, and provide a winter response scenario if oil spill response will occur in winter conditions.<sup>257</sup> The State of Alaska defines "typical winter environmental conditions"<sup>258</sup> as the period of time from November to April. A spill on October 31 would place oil in the sea in November requiring a winter scenario.

Shell only briefly addresses what it might do to clean up oil in the winter.<sup>259</sup> Shell theorizes that - if it is safe to place personnel on top of winter ice - it would attempt to recover oil by cutting trenches in the ice and pumping out the oil trapped under the ice. Ice mining tactics would be slow, inefficient and recover little oil during winter. Ice mining tactics have not

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<sup>255</sup> 18 AAC 75.445

<sup>256</sup> 18 AAC § 75.425(e)(1)(F) (requires: "a written description of a hypothetical spill incident and response that demonstrates a plan holder's ability to respond to a discharge of each applicable response planning standard volume within the required time frames using the resources described in the contingency plan and that identifies the spill location, time of year, and time of day, the source and cause of the spill, the quantity and type of oil spilled, the relevant environmental conditions, including weather, sea state, and visibility, the spill trajectory, and the expected timeline for response actions, describing response actions to be taken; the response scenario must be usable as a general guide for a discharge of any size, must describe the discharge containment, control, and cleanup actions to be taken, which clearly demonstrate the strategies and procedures adopted to conduct and maintain an effective response, and if the response scenario is for an exploration or production facility, must also meet the applicable requirements of (I) of this paragraph [emphasis added]."

<sup>257</sup> 18 AAC § 75.425(e)(1)(I) (requires: "a response scenario for an exploration or production facility – if the facility is an exploration or production facility, a response scenario that, in addition to complying with (F) of this paragraph, includes as part of the response strategies a summary of planned methods, equipment, logistics, and time frames proposed to be employed to control a well blowout within 15 days...a plan holder must provide a response scenario for a discharge of the applicable response planning standard volume under typical summer environmental conditions and typical winter environmental conditions [emphasis added]."

<sup>258</sup> 18 A.A.C. § 75.425(e)(1)(I)(iii) ("typical winter environmental conditions" means the average wind speeds and predominant wind directions as depicted by a wind rose, temperature, sea state, and other climactic and environmental conditions occurring during the period of November through April, based on National Weather Service data or local weather records of a duration sufficient to determine a reasonable average.").

<sup>259</sup> ODPCP at 3-34, 3-35. (Supplemental Information).

been tested and proven effective in the arctic for an oil spill response of this magnitude. The amount of oil that could be recovered using this method would be very small.

Oil spilled in ice-infested waters, and especially under the ice layer, is not only difficult to contain, it is very difficult to track and/or model.<sup>260</sup> Marine oil spill tracking and remote sensing technologies generally rely on air operations, which can be severely constrained by arctic environmental and logistical factors. Existing mathematical models cannot accurately predict the movement of oil on, under, or among offshore ice, although this is an area where considerable research and development remains ongoing.<sup>261</sup>

For oil that cannot be recovered using unproven ice-mining techniques, Shell suggests leaving oil in the sea over winter, to be dealt with the following spring.<sup>262</sup> Shell proposes:

“Should the location and removal of oil be impractical during the winter months, oil deposited beneath and trapped within the ice in this way could be dealt with (as described above) when it becomes naturally exposed in the spring/summer period.”

Oil trapped under ice may freeze and remain there, as it cannot evaporate. The oil will move with the ice until the spring melt and may ultimately be released a considerable distance from the spill site. This process has been referred to as “encapsulation” or an “oil-ice sandwich.”<sup>263</sup> Oil trapped under multi-year ice could remain in the marine environment for many years, up to a decade, and may not be released until it slowly migrates to the surface.<sup>264</sup> Overwintering or trapped oil will spread great distances and impact marine resources, subsistence resources and endangered species, and damage the coastlines of Native Allotments. And an oil spill trapped under ice cannot be tracked; Shell acknowledges that tracking oil trapped under ice and in thick ice is not currently possible, and that research is underway, but equipment is not yet available to do this work.<sup>265</sup>

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<sup>260</sup> WWF, Not So Fast: Some Progress in Spill Response, but US Still Ill-Prepared for Arctic Offshore Development A Review of U.S. Department of the Interior, Minerals Management Service’s (MMS) “Arctic Oil Spill Response Research and Development Program – A Decade of Achievement (Dec. 2009)..

<sup>261</sup> Pew Environment Group, Oil Spill Prevention and Response in the U.S. Arctic Ocean, Unexamined Risks, Unacceptable Consequences, prepared by Nuka Research and Planning Group, LLC., at Chapter 5.3.1. (Nov. 2010).

<sup>262</sup> Leaving oil in the sea over winter violates the State’s requirement to cleanup a well blowout of 480,000 bbls within 15 days.

<sup>263</sup> National Research Council (NRC). Oil in the Sea III: Inputs, Fates, and Effects. The National Academies Press. Washington, DC. (2003); Evers, Karl-Ulrich et al, State of the Art Report on Oil Weathering and on the Effectiveness of Response Alternatives, ARCOP (2004).

<sup>264</sup> Arctic Marine Assessment Programme (1998).

<sup>265</sup> ODPCP 3-35 (states: “Promising results of tests with ground-penetrating radar and other remote sensing systems could lead to the development and refinement of detection and tracking techniques for oil that is trapped deep within a thick ice layer (Dickins et al., 2006).” (emphasis added)).

Alaska law requires Shell demonstrate that it has access to enough equipment to meet the applicable response planning standards established under AS §46.04.030 and 18 A.A.C. §§75.430 - 18 AAC 75.445 using mechanical methods of oil control, containment, and cleanup.<sup>266</sup> The Plan does not provide any estimate of the oil that might be recovered using ice mining, nor does Shell demonstrate that it could use ice mining to cleanup a well blowout of 480,000 bbls within 15 days in winter conditions. Shell's oil spill plan states there are "proven" techniques for removal of oil from within or below ice;<sup>267</sup> however, Shell provides no peer reviewed scientific literature or field evidence to support such an assertion for the Beaufort Sea.

Shell should be required to include a credible winter oil spill response scenario in its ODPCP and demonstrate how it will cleanup a WCD spill occurring on October 31 in 15 days. If Shell's ODPCP only includes a summer oil spill response scenario, the ODPCP and EP should be revised to limit operations to the July-August timeframe, to allow time to cleanup oil in summer conditions.

### **XXIII. NSB Science Advisory Committee Recommendations to Mayor**

The ability to respond to an oil spill in periods of transitional ice is a significant concern given the response limitations discussed above. The North Slope Borough Science Advisory Committee (SAC), led by Dr. John Kelley, from the University of Alaska Fairbanks, undertook a study of measures to improve oil spill response in the nearshore Beaufort Sea. The SAC review was completed in May 2011, and the findings were published in a report entitled *Mechanical Oil Spill Response Technology and In Situ Burning Technology for Removal of Oil in the Near-shore Beaufort Sea During Periods of Spring Rotting Fast Ice, Spring Break-up Broken Ice and Fall Freeze-Up Ice*. The report is attached (Attachment No. 5).

The NSB SAC made 16 recommendations for improving oil spill response in the nearshore Beaufort Sea. Because Shell's proposed activities create a risk for an oil spill in the nearshore area of the Beaufort Sea, these recommendations are applicable. NSB requests that BOEMRE require modification of Shell's EP and ODPCP to address each recommendation listed below:

- 1. A Response Gap analysis should be completed for the nearshore Beaufort Sea area to statistically analyze current response limitations.** A "Response Gap" is the period of time when oil spill response is not possible (or is rendered so inefficient as to be futile) because one or more limiting factors prevent an effective response (eg. weather, sea ice, wave height, darkness, and extreme cold). An effective response requires the ability to locate

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<sup>266</sup> 18 AAC 75.445(g)(1).

<sup>267</sup> ODPCP at 1-31 ("Proven techniques for the removal (or mining) of oil from within or below ice (see ACS Tactics R-5, R-13, R-14, R-29, and R-31) may be feasible where it is safe to access and work on a stable ice layer.").

and track the oil, access to the spilled oil (equipment capable of transporting people and equipment to the spill site and supporting the response operations); environmental and oil spill conditions safe enough for people to operate response tools; and response tools that are effective for the type of oil spilled and the environmental conditions encountered. In the Arctic, there are a number of factors that limit response. To more thoroughly evaluate the response limits for the near-shore Beaufort Sea area, a Response Gap analysis should examine the combined impact of response limits identified in this report. The Response Gap analysis should identify the weakest link in the response chain. The analysis will provide a statistical assessment of the number of days that an oil spill response is not possible (or is rendered so inefficient as to be nearly useless).

2. **Improved oil spill prevention methods and seasonal operating restrictions should be instituted during periods when oil spill response is not possible.** Industry should ensure that its C-plan calls for the best available technology to improve oil spill response methods, including improved tank containment, pipeline design, leak detection systems, overfill alarms, blow-out preventers, subsurface safety valves, wellhead controls, etc. One of the most important prevention methods is to refrain from drilling during periods of broken ice and open water, when spilled oil would be very difficult to recover. This prevention method is specifically required in the NSB Municipal Code.
3. **Port infrastructure improvements are needed along the Beaufort Sea coast line.** There is insufficient port infrastructure along the Beaufort Sea coastline to support a large-scale oil spill response. Additional port infrastructure and equipment caches along the coastline will improve access and expedite response.
4. **Ice class tugs and barges must be added to the Beaufort Sea equipment inventory.** The ability to logistically access spilled oil and use either mechanical or *in situ* burning methods, is currently limited by the lack of ice class vessels. There are no ice breaking vessels or ice reinforced barges available in the nearshore Beaufort Sea at this time. The existing vessel inventory is not designed to operate in ice conditions over a few percent. The response fleet should include ice class tugs and barges to extend the oil spill response operating window and response effectiveness.

[Note: This recommendation only partially applies to Shell. Unlike, other North Slope operators, Shell has provided deeper draft ice breakers and ice classed vessels in its ODPCP. Where Shell can improve is to add shallow draft ice capable and ice class vessels to respond to a late season blowout. Once ACS's aluminum vessels are removed from the Beaufort Sea in early October, Shell has no nearshore and shoreline response vessels because its deeper draft ice class vessels cannot operate in the shallow waters.]

5. **More arctic-grade oleophilic brush skimmers should be added to the Beaufort Sea equipment inventory.** 2008-2009 SINTEF studies in Norway concluded that the LRB 150 Oleophilic Brush Skimmer is the best available technology. ACS reports that it has one LRB 150 skimmer in its inventory. Additional LRB 150 skimmers should be purchased for the ACS inventory in a number sufficient to respond to the largest oil spill volume in the Beaufort Sea.
6. **Skimming units that separate oil from ice are needed for ACS inventory.** A significant amount of ACS R&D funding was invested into developing the MORICE skimmer for use in higher ice concentrations but this skimmer is still not commercially available. SINTEF reports that other skimming units are commercially available and effective for separating oil from ice. ACS should purchase the best available units for its inventory to expand the response window.
7. **Exxon Valdez Oil Spill (EVOS) equipment in ACS's inventory should be replaced with new, improved equipment.** ACS's inventory includes a number of pieces of EVOS equipment. This equipment is now over 20 years old and should be replaced with new equipment that meets a best available technology standard. Any EVOS equipment that is retained should be tested to confirm that it is suitable and capable of performing its intended function.
8. **Field trials and experiments should be conducted in the Beaufort Sea.** Actual oil spill experiments and field trials are needed in the Beaufort Sea, with Beaufort Sea oil samples used to improve tactics, improve response equipment and train personnel. Testing of both surface release spills and subsurface released spills should be conducted.
9. **ACS inventory needs boom upgrades.** The ACS inventory should be improved to include ice-capable open water containment boom (e.g. Norlense) and other high tensile strength boom.
10. **ACS's personnel and equipment must be commensurate with its area of operation and responsibilities.** ACS's offshore response obligations were originally limited to the near-shore Beaufort Sea area due north of Prudhoe Bay, extending west towards Kuparuk and east towards Endicott. Today, ACS's sponsors have vastly expanded to include operators and operations much further east, west and north. Onshore response obligations have also expanded. While ACS's obligations and geographic area of responsibility has greatly increased, its personnel and equipment has not kept pace. ACS equipment must be maintained in a sufficient quantity to support all its needs. Equipment must be kept close to potential spill locations, or ACS must demonstrate that it has the logistic support to rapidly place it on spill location.

11. **ACS's tactic manual should be upgraded to include ice management equipment and tactics.** Nuka Research and Planning Group, LLC recommended ice management equipment and tactic improvements.<sup>268</sup> Details of these recommendations are in the SAC report attached.
12. **Oil Spill Response Plans should more accurately depict oil spill response limitations.** Oil spill response plans do not accurately depict equipment and human inefficiencies in arctic response conditions, and the inability to access oil because of safety, ice and logistical constraints. The information documented in this report, and the report gap analysis report recommended above, should be used to revise existing plans. A clear, concise description of human safety limitations (for response operations) should be included.
13. **Dispersants should not be used in the near-shore Beaufort Sea at this time.** There is insufficient human health, biologic and toxicological data to ensure dispersant use in the Arctic is safe. Dispersants do not remove oil from marine waters. Most of the near-shore Beaufort Sea area water depth is too shallow for dispersant use. Arctic dispersant formulations are still being developed, and are not effective in shallow waters. There are inadequate stockpiles of dispersants and logistical support on the North Slope to apply dispersants in the narrow window of applicability.
14. **Herding agents appear to be a promising tool but should not be used in the nearshore Beaufort Sea at this time.** There is insufficient human health, biologic and toxicological data to ensure herding agent use in the Arctic is safe. Herding agents show promise as a tool to thicken oil to a point where in situ burning may be possible. Additional research should continue.
15. **Additional equipment is needed to improve in situ burning capability.** Burn efficiencies exceeding 90% can be achieved if oil can be contained and thickened to ~5-6mm. However, burn efficiencies will be substantially lower for thin slicks, subsurface oil releases, and weathered crude oil. Tools are needed to identify and track pools of oil that are thick enough to burn to concentrate limited resources on the areas with the greatest potential for successful in situ burning. There are significant logistical, technical, and safety challenges that remain in tracking, accessing, and igniting oil slicks and recovering burn residues. It should be ensured that ice class vessels are added to the ACS inventory to improve access to spilled oil to initiate burns, and additional aircraft support equipped with ignition equipment is needed to increase the ability to simultaneously ignite a large number of burns, and sustain the burns.

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<sup>268</sup> Nuka Research & Planning Group, LLC. (2007). 2007. Oil spill response mechanical recovery systems for ice-infested waters: examination of technologies for the Alaska Beaufort Sea. Prepared for Alaska Department of Environmental Conservation, at 100 (Conservation. June 2007)..2007.

**16. Further research and development are needed in the following areas:**

- a. Toxicity testing on dispersants and herding agents is needed to verify safety for arctic species.
- b. Additional scientific studies are needed to better understand the toxicity of residual material left behind after a burn that cannot be recovered.
- c. Improved tools are needed to measure and map oil spill thickness to identify areas of pooled oil that may be thick enough to collect or burn. Multispectral aerial sensor technology and infrared detection tested in California is promising; however, arctic tests are needed.
- d. Improved tools are needed to detect and map oil among drifting broken ice and encapsulated in and under ice.
- e. Mechanical response tools are needed that are effective in spring broken ice and fall freeze-up conditions.
- f. Methods are needed to recover oil trapped under ice.
- g. Methods and tools are needed to respond to subsea spills.

For this EP and ODPCP, BOEMRE and Shell should address each recommendation made in the NSB SAC Report entitled *Mechanical Oil Spill Response Technology and In Situ Burning Technology for Removal of Oil in the Near-shore Beaufort Sea During Periods of Spring Rotting Fast Ice, Spring Break-up Broken Ice and Fall Freeze-Up Ice*.

**XXIV. Duration of Operations**

Shell requests approval to drill from July 10 to October 31, and temporarily suspend operations during the Nuiqsut (Cross Island) and Kaktovik subsistence bowhead whale hunts starting on approximately August 24.<sup>269</sup> The temporary suspension will continue until the whale hunting quota is achieved or the hunt is concluded. Shell plans to return to Camden Bay to resume activities after the subsistence bowhead whale hunts conclude.<sup>270</sup>

Shell's plans to continue drilling in Camden Bay in September and October are inadequately supported by Shell's EP and ODPCP. As detailed in these comments, Shell has not

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<sup>269</sup> EP at 2-5, EP at Section 6, EP at 12-2 ("Shell plans to voluntarily shut down exploration drilling operations on August 25 for the Nuiqsut (Cross Island) and Kaktovik subsistence bowhead whale hunts. During the suspension for the whale hunts the drilling fleet will leave the Camden Bay project area and move to an area north of latitude 71° 25'N and west of longitude 146° 4'W. Shell will return to resume activities after the subsistence bowhead whale hunts conclude.").

<sup>270</sup> EP at 2-5.

demonstrated that it can respond to a late season oil spill,<sup>271</sup> or operate its equipment in winter ice and storm conditions that may be encountered if a relief well or well capping and containment system is needed during the months of November and December to respond to a late October well blowout.<sup>272</sup> Nor has Shell built or tested an arctic well capping and containment system to control a well blowout.

BOEMRE has the authority to approve the EP with conditions<sup>273</sup>, or return the EP to Shell and require Shell to revise it to meet federal law and regulations.<sup>274</sup> BOEMRE should return Shell's EP for substantial modification.<sup>275</sup> If BOEMRE decides to approve Shell's EP, among other conditions, BOEMRE should limit drilling operations to July and August unless Shell has demonstrated it has planned for and is prepared to address a late season spill scenario. Otherwise, limiting drilling operations to the July and August timeframe will provide an opportunity to clean up an oil spill in September before encroaching ice and winter storms make cleanup impossible.

## **XXV. Biological Resources**

Shell's Exploration Plan (EP) for Camden Bay for 2012 contains a number of improvements over their previous plans. The decrease in discharge into the Beaufort Sea compared to previous plans and discontinuing exploratory drilling during the Kaktovik and Nuiqsut bowhead hunts during the fall season are noted improvements. Despite these improvements, however, Shell's plans will likely have substantial and significant impacts on the resources in the Beaufort Sea.

Throughout the exploration plan and appendices, Shell concludes that impacts will be negligible. Unfortunately, in most cases they do not have the data to support the claims but instead speculate about the impacts. The best available science shows that marine mammals, especially bowhead whales, may be deflected away from industrial activities and in some cases may be nearly excluded from an area within 20km of a drilling platform (Davies 1987; Hall et al. 1994: see Shell's EP for references). Shell is requesting in its Incidental Harassment Authorization application, permission to "take" up to ~5600 bowheads. This represents almost half of the population. The short-term effects on bowheads can be deflection, disturbance, or changes in behavior. No one has studied the long-term effects of industrial activities on bowheads. Despite their claims of negligible impacts, Shell also acknowledges (Appendix F,

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<sup>271</sup> A late season oil spill would be an oil spill that occurs in late October, spilling oil into the Beaufort Sea requiring oil spill clean-up in November and December, and likely beyond that date depending on the spill size, and weather conditions.

<sup>272</sup> 30 C.F.R. §254.

<sup>273</sup> 30 C.F.R. §250.233(b)(1).

<sup>274</sup> 30 C.F.R. §250.233(b)(2).

<sup>275</sup> 30 C.F.R. §250.233.

page 4-61) that for bowheads “it is not known whether impulsive sounds affect reproductive rate or distribution and habitat use in subsequent days or years.” This same statement is true for continuous sounds such as exploratory drilling. Given the lack of important information on long-term effects and the potential for “taking” almost half the bowhead population, extra care must be taken in evaluating impacts, both from the planned activity and from cumulative impacts. Additional effort should also be applied toward developing appropriate and effective mitigation measures.

In its documents, Shell has a tendency to reference summary articles to support conclusions or provide data instead of using the primary literature. This approach is a disservice to the public and decision makers. It makes it very difficult to evaluate claims made in the exploration plan or its appendices if the primary literature is not referenced. For example, in the Marine Mammal section of the Environmental Impact Assessment, there is a repeated use of Angliss and Outlaw (2008). This reference contains the Alaska marine mammal stock assessment reports. Angliss and Outlaw did not conduct research for this publication but summarized other people’s work. The original work should be referenced.

The cumulative impacts section is incomplete and inadequate. Shell only considers other activities that occur in the Alaskan Beaufort Sea and not the other areas where the biological resources travel, such as bowhead and beluga whales that also occur in the Canadian Beaufort, the Chukchi Sea, or the Bering Sea. A detailed description of activities is needed along with an adequate quantitative analysis.

#### Specific Comments

Section 5.0 “Biological, Physical and socioeconomic information”, Dunton et al. (2009) Report: This is an incomplete summary of the report. Most of the information given here is regarding the methods and even then it is unclear. For example, the section states: “One sample each was collected at 19 sites across the monitoring area to describe the spatial extent and the patterns of biota biomass and density in the.” This does say what kind of samples were collected and the amount of samples taken at the 19 sites. Further, there is no map showing the study area and sampling stations. And, there is no data table summarizing the objectives, results and conclusions from the report.

Given the small extent of the study area it is no surprise that Dunton et al. (2009) did not observe spatial trends in the biomass or density of the benthic organisms. Small scale studies are very likely to miss the patch size of the organisms that are being studied. In order to detect spatial trends the sampling grid should be larger than the area of the lease blocks.

Therefore, the conclusion that no spatial trends in biomass or density were observed is meaningless, given the scale in which the study was conducted.

Furthermore, this section states, “benthic communities have not been adversely affected by previously discharged mud and cuttings during drilling operations at the former Hammerhead prospect drill sites.” These operations were conducted in the 1980’s, to conclude that there were no adverse affects is not supported by the study. It would be more acceptable to state that: 1) benthic the communities may have been affected by the drilling operations but may have recovered in the last 25 years such that benthic community structure is similar to the one described in 1980; 2) the benthic communities may not have been affected by the drilling operations but there is no evidence to confirm that since no benthic data were collected in the area between the study area between the 1980’s and mid 2000’s.

Appendix C, Incidental Harassment Authorization Application (IHA): These do not reflect our full comments on Appendix C. Once the National Marine Fisheries Service requests comments on the final version of the application, we will comment more fully.

Pg. 1&2: Shell is asking to “take” ~5600 bowhead whales. This represents approximately one-third to one-half of the population. In Table 6-4, page 41, Shell suggests that the maximum number of bowheads that may be exposed to industrial sounds  $\geq 120$  dB may actually be ~11,150, almost the entire population. The impacts to bowheads may be substantial and significant. Additional data are needed on long-term impacts. Furthermore, it seems hard to justify “taking” either 5,600 or 11,150 bowheads through an IHA qualifies as a “small number” as required by the Marine Mammal Protection Act.

Pg. 30, penultimate paragraph: Shell is requesting “takes” only for sound. Because they will be discharging a large amount of cooling water and some muds and cuttings, and because bowheads (and possibly belugas) respond to smell and other substances humans introduce into the water or air, takes should also be evaluated and requested for discharges.

Pg. 31, 1<sup>st</sup> paragraph: Shell states that “...there is no specific information demonstrating that injurious takes would occur...”. This sentence implies that the burden is on someone else to show there was an injurious take. The burden should instead be placed on Shell to undertake a study to actually look for injurious takes. No study has yet been conducted on bowheads or belugas, despite some evidence that bowheads have possibly been struck and killed by vessels. Injuries may also have been sustained to

whale hearing, yet no data currently exist to evaluate hearing loss in whales. Better information is needed to support Shell's statement.

Pg. 31, 3<sup>rd</sup> paragraph: Shell states that "[t]here is no evidence that avoidance at received sound levels  $\geq 120$  dB or  $\geq 160$  dB would have significant biological effects on individual animals or that subtle changes to behavior or movements would 'rise to the level of taking according to guidance by NMFS (2001).' There are no data to support this statement and in fact Shell states in Appendix F, page 41 that for bowheads "it is not known whether impulsive sounds affect reproductive rate or distribution and habitat use in subsequent days or years." Available data show that bowheads deflect away from anthropogenic sounds. Instead, a precautionary approach should be used that assumes deflections may have significant effects until the weight of evidence suggests otherwise.

Pg. 34, last paragraph: Shell uses a point estimate of the population size to estimate the number of bowheads that may be exposed to industrial sounds. The population estimate includes confidence limits that are a better reflection of our state of knowledge about the size of the bowhead population. Those confidence intervals should also be used for estimating the number of bowheads that might be exposed to industrial sounds. A lower and upper estimate should be provided for a better assessment of the number of whales potentially impacted.

Pg. 49, Baleen Whales: This summary of the response of baleen whales to industrial sounds is not sufficient. Available studies indicated that the "zone of avoidance" of bowheads around a drill rig in Camden Bay was 15 to 25km (LGL and Greeneridge 1987), the deflection of bowheads away from the drill rig began at about 32km away (Brewer et al. 1993), and that bowheads were excluded from about 20km around a drill rig in Camden Bay (Hall et al. 1994, Davies 1997).

Pg. 63 and 64, Impacts on habitat: The IHA application does not evaluate the impacts from discharge. Recent studies have shown that bowheads can smell, contrary to conventional knowledge. Thus, bowheads can likely detect and avoid discharges. This issue should not be ignored but evaluated in the IHA application.

#### Appendix F, Environmental Impact Assessment:

Preface: Shell states that available studies show that there have been no long-term impacts on the Beaufort Sea environment from industrial activities. There are few studies to

support this conclusion, particularly with regards to bowhead whales. The available studies are short-term in nature. The bowhead population is growing but there are no data to suggest how the population may have responded in the absence of industrial activities. In the absence of industrial activities, the bowhead population may have grown more quickly. Furthermore, the increasing interest in the Arctic for not only oil and gas but also for transportation and commercial fishing in combination with climate change may cause future impacts to be substantial and significant. Past short-term impacts to subsistence hunting have been mitigated through the Conflict Avoidance Agreement between the Alaska Eskimo Whaling Commission and industry; however no data exist on longer-term impacts. Additional information is needed for long-term and cumulative impacts from industrial activities on subsistence resources.

Pg. 2-46: To estimate exposures of whales to industrial sounds from airguns, Shell is using a sound level of  $\geq 160$ dB. This is not sufficient and does not take into account the best available scientific data. Bowheads respond to impulsive sounds from airguns at sound levels below 160dB and possibly below 120dB. Using the 160dB level, multiplied by 1.5 as a safety factor, a distance of 18km from the airguns has been calculated by Shell. Bowheads within that zone would be exposed to  $\geq 160$ dB of impulsive sounds. Using the 120dB level, the distance would be almost twice as far at 34.5km. Using the 160dB threshold means that Shell is underestimating the number of whales that will be exposed to industrial sounds that are producing from their airgun array.

Pg. 2-52, Vessel Traffic, 1<sup>st</sup> bullet: Shell proposes to move the Kulluk or Discoverer through the Chukchi Sea on about July 1, 2012. Beluga hunters at Point Lay do not want to see the drilling rig or ship in the Chukchi Sea until July 15 or until the beluga hunt is completed. Transit of the vessels through the Chukchi Sea could cause the belugas to avoid the traditionally used coastal areas which would result in the loss of the availability of belugas for subsistence hunters at Point Lay. Regarding bowheads, reactions are variable, however Richardson and Malme (1993; p 691) reported: "Boat noise as low as 84 dB or 6 dB above ambient elicited strong avoidance of an approaching boat."

Pg. 2-52, 2<sup>nd</sup> bullet: Suspension of drilling in Camden Bay will occur on August 25 and Shell and the AEWC will agree on a location where the drill rig and support vessel will be moved to until the bowhead hunts at Kaktovik and Nuiqsut are completed. This is appropriate but others should be involved in the decision as well. Because belugas use the shelf break and deeper waters of the Beaufort Sea, moving the rig and other vessels to the shelf break may be helpful for bowheads but may negatively impact belugas.

Pg. 31, 3.1.1 to 3.1.5: Shell presents meteorological and ice data for the Beaufort Sea. This information is vital in many regards, including oil spill cleanup activities. Shell should be required to conduct an analysis of the percentage of time that environmental conditions (i.e., wind speed, temperature, ice cover, fog) might impede their ability to respond to an oil spill using their various approaches to cleanup. This information would help decision makers and the public understand the limitations in oil spill cleanup technologies and practices.

Pg. 3-49, Alcids: Short-tailed Shearwaters are not alcids. They are tubenoses or Procellariiforms.

Section 3.6, Coastal and Marine Birds: Shell needs to use the most recent data. References to Larned et al. 2007 occur throughout this section. More recent data, up to 2010, exist. Throughout this section, there is a failure to mention that many of the birds using the Beaufort Sea and potentially impacted by activities in Camden Bay migrate to Canada. Using the Larned data, even the most recent information, only provides data on the numbers of birds in northern Alaska and not those that may be nesting in Canada. The result is that decision makers and the public are left with the impression that fewer birds may be impacted than in reality. It also needs to be pointed out that a large percentage of some bird populations, such as Pacific Eiders, King Eiders, Yellow-billed Loons, etc., use the Beaufort Sea. In the event of a large oil spill, almost an entire population could be impacted.

Pg. 3-56, Waterfowl Abundance: Suydam et al. (2000) did not suggest that Common and King eider population declines could be due to hunting. They stated that causes of the decline were unknown.

Pg. 3-64, Harbor Porpoise: Shell states that harbor porpoise are “not migrating animals”. Harbor porpoises could not survive in the Beaufort Sea during the winter because of ice cover. Thus, the porpoises migrate from other locations to the Beaufort Sea.

Pg. 3-68, Beluga Whale: Shell mischaracterizes beluga hunting in North Slope communities. Belugas are hunted in Point Hope primarily in April and May. Belugas are hunted in Point Lay, Wainwright, Barrow, Nuiqsut and Kaktovik during open water periods, late June through August or early September.

Pg. 3-68, last paragraph: Contrary to Shell’s claim, there are many belugas in the Beaufort Sea during the summer. Belugas from the Chukchi Sea stock primarily summer along the

shelf break of the Beaufort Sea (Suydam et al. 2005). An oil spill in Camden Bay during the summer could impact belugas during the summer and the autumn.

Pg. 4-1, Environmental Impacts, 2<sup>nd</sup> paragraph: Shell states that minimal or negligible impacts are expected. This is probably a true statement but there are few supporting studies. They plan to drill four exploratory wells, discharge some muds and cuttings and cooling water, and introduce a substantial amount of industrial sounds into the water. Based on the best available data, there could be substantial and significant impacts to bowheads and possibly other marine mammals. Evaluation of environmental impacts should be conducted in as thorough a manner as possible including involvement with the public involvement.

Pg. 4-11: Shell concludes that the discharge of cooling water and other discharges will have a negligible effect on zooplankton, important food for some marine mammals. What data or studies are being used to support this claim? No references are provided. Additional data are needed on the impacts of cooling water on arctic zooplankton.

Pg. 4-22, penultimate paragraph: Shell notes that bird densities are low in the project area thus conclude that impacts to birds will be negligible. Unfortunately they do not take into account the birds migrating through the area. Large numbers of eiders, loons, and other birds move through the Beaufort Sea and could be impacted by activities in Camden Bay. A more thorough analysis of potential impacts to coastal and marine birds is needed.

Sections 4.1.8, Marine Mammals, and 4.1.9, Threatened and Endangered Species: There is a relatively thorough discussion about impacts from industrial sounds and activities on marine mammals throughout the world. Surprisingly there is little specific or detailed discussion or analysis of the impacts on bowheads in the Beaufort Sea. In its IHA application, Shell asks to “take” up to ~5600 bowheads. Even if the impacts are short-term, deflecting or disturbing so many bowheads could have substantial and significant impacts, yet there is no analysis of the impact of taking such a large proportion of the population. One is needed.

Pg. 4-56 and 57: Shell states that “no significant or lasting impacts to marine mammals are expected from sound energy that will be created by drilling and ice management activities in Camden Bay.” That conclusion is not supported by data. As mentioned previously, no long-term studies have been conducted on impacts from marine mammals due to industrial sounds in the Beaufort Sea. Short-term impacts have been

documented but information is needed about how those short-term impacts could contribute to longer-term impacts on individuals and the population. Shell points to previous NMFS conclusions that there will not be lasting impacts. Unfortunately, NMFS also makes that conclusion without the support of data. To protect the resources and the Inupiat who depend on them, a more precautionary approach is needed until information about longer-term impacts is available.

Section 4.2, Cumulative Impacts: This section is not sufficient for several reasons. Shell limits its discussion of human activities to the Alaskan Beaufort Sea. Many of resources, particularly the biological ones, are exposed to human activities in the Canadian Beaufort Sea, the US and Russian Chukchi Sea and the Bering Sea. A more appropriate and thorough cumulative impacts analysis is needed. Additionally, the “analysis” in this section is mostly speculation. A quantitative approach is needed to assess cumulative impacts on all resources. Based on a number of measures, the overall health status of BCB bowheads is thought to be “good” (i.e., increasing population, low disease rates); however the conclusion of Richardson and Malme (1993; p. 692) nearly two decades ago is still true: “In general, there is little information [for bowhead whales] about the cumulative and long-term consequences of repeated or continuous exposure to man-made noises.”

#### Reference:

Richardson and Malme (1993). Richardson, W.J., and Malme, C.I. 19 93. Man-made noise and behavioral responses. In: J.J. Burns, J.J Montague and Cowles, C.J. (eds.). The Bowhead Whale. Allen Press, Lawrence, Kansas.

#### Appendix D: Marine Mammal Monitoring and Mitigation Plan

Generally, Shell’s proposed Marine Mammal Monitoring and Mitigation Plan (4MP) includes the basic components recognized as appropriate tools for offshore monitoring of the effects of drilling activities on marine mammals. These components include: ship based observations by MMOs, structured aerial surveys, and acoustic monitoring. We are in support of Shell’s plan to estimate numbers of marine mammals exposed to noise within the 120 dB isopleth. We particularly appreciate the serious consideration of the degree of long-duration deflections of bowheads whales from industrial operations (e.g.; p. 11 bullets 4 and 5; *(4) to investigate potential deflection of bowhead whales during migration by documenting how far east of exploration drilling operations a deflection may occur, and where whales return to normal migration patterns west of the operations; and (5) to monitor the accessibility of bowhead whales to Inupiat hunters.*

An aspect that is absent is monitoring of the down-stream effect of drilling associated exhaust and in-water plumes on the migrating bowheads considering Inupiat traditional knowledge observations and recent work regarding bowhead olfactory sense.

p. D-16; 1<sup>st</sup> numbered bullet reads: *"Numbers of cetaceans observed within the area ensonified strongly by the exploration drilling operations.* For cetaceans, Shell will estimate the numbers of animals exposed to received rms levels of sounds exceeding 120, 160 dB and 180 dB re 1 µPa, as required by NMFS."

The NSB is pleased to see responsiveness to our concerns regarding quantitative estimates of the number of animals exposed to noise within the 120 dB zones.

p. D-24 and 25; Regarding analyses of deflections of migrating bowheads, the proposed design of the acoustic array and analysis of the data seems reasonable. We support their interpretation that acoustic data produces far greater sample sizes than aerial surveys but can be difficult to interpret. Shell also recognizes that bowheads in ensonified zones reduce call rates which complicates impact analyses. In that regard, we recommend that Shell modify their statement: *"Bowheads call frequently in fall, but there is some evidence that their calling rate may be reduced upon exposure to industrial sounds, complicating interpretation."* This statement should be changed to reflect the fact that there is strong evidence that bowheads modify calling rates in the presence of industrial sounds (Blackwell et al., various publications).

## **XXVI. Cooperation and Consultation with Local Governments**

OCSLA regulations require BOEMRE "to cooperate and consult" with local governments when establishing performance standards for lease operations.<sup>276</sup> NSB respectfully requests that, consistent with this legal obligation,, BOEMRE respond to this comment letter and explain what changes BOEMRE will require in response to NSB comments, or explain why certain comments are disregarded.

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<sup>276</sup> 30 C.F.R. §250.106(d).