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Secretary of the Board
National Energy Board
444 Seventh Avenue S.W.
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RE: *Draft Financial Viability and Financial Responsibility Guidelines*

ConocoPhillips Canada ("ConocoPhillips") greatly appreciates the National Energy Board's (NEB) efforts to provide guidance on the determination of applicants' financial viability and responsibility under the *Canada Oil and Gas Operations Act* (COGOA), and the opportunity to provide comments on the *Draft Financial Viability and Financial Responsibility Guidelines* (Draft Guidelines). In commenting on the Draft Guidelines, ConocoPhillips recognizes the NEB's broad discretion under section 27 of the COGOA. Given the NEB's broad discretion, the absence of other regulatory instruments addressing financial responsibility, and the fact that financial viability and responsibility are administrative matters under the COGOA, clear and appropriate guidelines are critical in providing transparency for stakeholders and regulatory fairness, clarity and certainty for applicants.

While the Draft Guidelines provide a new level of clarity about financial risk assessment and mitigation information the NEB will require from applicants for all activities under the COGOA, in ConocoPhillips' view, in their current form they do not completely achieve the goals identified above. ConocoPhillips' main reasons for this conclusion are that the Draft Guidelines:

1. as a result of the language of the definition of worst case scenario, make a pre-determination about the nature of the worst case scenario for every possible activity governed by the COGOA;

2. do not sufficiently distinguish between offshore and onshore operations and among the various kinds of possible offshore and onshore activities, wells and facilities;

3. contain no guidance on how potential discharge volumes are to be calculated, which is a critical element for determination of financial responsibility;

4. provide no information on the NEB's process for determining the amount of unfettered funding it may require, minimal information on the NEB's process for determination of the nature of the instruments that will be required to secure those funds, and no information on how the NEB will manage the:

    a. potential "overlap" of its security requirements with those of other regulators for the same activities, particularly for the onshore,
    b. the adjudication of claims potentially made to multiple regulatory authorities by those who may suffer losses from an event, and
    c. return of financial instruments;

5. require certain information that, in ConocoPhillips' opinion, is unnecessary, impossible to provide, or without precedent anywhere in the world.

ConocoPhillips submits that the Draft Guidelines must address the foregoing issues in order to accomplish the goals of transparency and regulatory fairness, clarity and certainty. To that end, the Company offers the following comments.

Definition of and Determining a Worst Case Scenario

The Draft Guidelines require a worst case scenario to be identified by the applicant for every COGOA regulated activity, and characterize a worst case scenario as a "severe event with extreme and significant effects and consequences". Therefore, assuming that "event" refers to a discharge of hydrocarbons (this is not entirely clear in the definition, though implied, perhaps, in the surrounding text of the Draft Guidelines) the Draft Guidelines apparently start with a pre-determination that all activities in all regions under COGOA can result in a discharge that is a "severe event with extreme and significant effects and consequences".

A pre-determination that every COGOA regulated activity has the potential to cause a "severe event that could have "extreme and significant effects and consequences" appears based on an assumption that "anything is possible". That assumption and the definition as drafted, could require an applicant to identify an event that, though it may be remotely possible, is either entirely improbable or so unlikely and remote that it could not justify serious consideration in planning. This is an approach that is fundamentally unfair and potentially and unnecessarily, highly misleading and alarming for stakeholders. Such an approach is contrary, too, to the way that "worst case scenario" has been addressed in practice under the *Inuvialuit Final Agreement*.

One approach to remedy this result of the current construction of the definition of the worst case scenario is for those activities where hydrocarbon reservoir discharges or hydrocarbon discharges from production or transportation facilities are not reasonably foreseeable to be explicitly excluded from the requirement to identify a worst case scenario. Alternatively, the worst case scenario should be re-defined in the Draft

Guidelines to align with the approach in the NEB's *Filing Requirements for Offshore Drilling in the Canadian Arctic* (Filing Requirements).
The Filing Requirements, in section 4.17a)1., define a worst case scenario in terms of "the estimated flow rate, total volumes of fluids, oil properties, and maximum duration of a potential blowout." In 4.18(5) of the Filing Requirements, the consequences of a worst case oil spill scenario are determined separately as a factor in the consideration of environmental effects. In other words, rather than attempting a "one size fits all" definition, the worst case scenario should be re-defined to focus upon the questions that need to be asked rather than attempt to account in a few words for an almost infinite range of potential events and outcomes. The worst case scenario should, instead, be determined in each case by clearly addressing the following questions:

1. Could the planned activity result in an uncontrolled discharge of reservoir fluid from a well or product from a facility?
2. If yes, what is the flow rate, how long would the discharge last and what is the volume of the discharge and the properties of the fluids?
3. What would be the potential costs to contain, clean up and compensate for damages caused by the discharge?

As the Draft Guidelines are currently drafted, it is likely that each applicant will apply a different process for answering these fundamental questions, potentially leading to varying results for roughly equivalent projects and scenarios. By focusing applicants on these questions and providing guidelines for answering them, the NEB might be better able to achieve consistency among approaches to worst case scenario identification and to make accurate distinctions among projects. One approach, which would also encourage a consistent approach from applicants, could be as follows.

An applicant would, for any case where a discharge is determined to be within the realm of reasonably foreseeable possibilities:

1. Assess the scenario for residual risk level on the basis of likelihood and severity.
2. Apply a likelihood and severity risk matrix to rank the risk level – High, Significant, Medium-High, Medium Low, Low, None.
3. Apply mitigation and reassess likelihood and severity.
4. Rank residual risk (Residual risks are considered to be risks that remain once all identified and proposed mitigation is considered/applied.). This may result in another round of mitigation and ranking.
5. Only where a residual risk is ranked Medium to High, apply a specific Spill Contingency Plan for the scenario; if mitigation is sufficient to reduce a Risk to Low, then no specific Contingency Plan would be needed.

Such an approach will also help to clarify the scope of the consultations the NEB is requiring in the Draft Guidelines. Consultation on the potential consequences of an unlikely and improbable event is of little value in setting the levels of financial responsibility. It must also be recognized that the determination of the volume of a potential discharge needs to be focused on an applicant's professional, expert opinion and consultation with subject matter experts. Most of these calculations and the factors

they include cannot be adequately addressed by lay persons. Further, many of the inputs used for the calculation of potential discharge volumes and related costs of containment and clean-up will be based on confidential information that is part of privileged filings with the NEB.

The advantages of this proposed approach to the definition of worst case scenario are that:

1. the Draft Guidelines and the Filing Requirements would be consistent;
2. there would not be a fundamentally unfair pre-determination that the worst case discharge of every activity would have "extreme and significant effects and consequences";
3. addressing the potential for discharge and potential volume, as provided for in the Filing Requirements, creates a rational and transparent basis for consultations on potential environmental effects and the adequacy of management systems, proposed prevention measures, mitigation, spill response plans, and spill response capability; and
4. this approach could also address some of ConocoPhillips' other concerns.

Differences among Operations, and Calculation of Discharge Volumes

A re-crafting of the definition of worst case scenario as suggested above, particularly by looking at the three questions on a case by case basis, would likely accommodate differences among types and locations of operations and facilities. A consistent, general approach need not be "one size fits all". A look at the approaches taken in other jurisdictions could provide further assistance in clarifying the processes for answering the questions related to a determination of a worst case scenario noted above. For example, clear guidance on questions 1 and 2 is provided in the United States' Codes of Federal Regulations, Title 30: Mineral Resources, Title 40: Protection of Environment and Title 49: Transportation.

The United States' Codes of Federal Regulations set out the parameters that need to be addressed in calculating a discharge volume and clearly account for the differences between onshore and offshore locations and among different types of wells and production, storage and transportation operations and facilities. The Draft Guidelines should incorporate or at least clearly provide for the application of similar criteria to establish a consistent and transparent basis for the calculation of discharges.

More broadly, based on its experience with operations in British Columbia, Alberta and Saskatchewan, ConocoPhillips suggests that before they are finalized, the Draft Guidelines take into account the general regulatory framework for onshore activities. In reviewing the Draft Guidelines, it becomes apparent that the engagement started with the Arctic Offshore Drilling Review needs to be expanded to include onshore activities under the COGOA before the Draft Guidelines can be completed. ConocoPhillips recommends that, pursuant to the *Cabinet Directive on Regulatory Management*, the regulatory framework for onshore activities be assessed to ensure that what the Draft Guidelines require will not impose unnecessary regulatory burdens in the Northwest

Territories and Nunavut, especially compared to other jurisdictions in Canada. This would require a review of the onshore regulatory framework, and ConocoPhillips would be happy to participate in such an assessment.

Financial Responsibility

ConocoPhillips respectfully submits that the Draft Guidelines' requirement for unfettered funds should explicitly align with the federal government's commitment to the "polluter pays" principle as set out in the June 2013 announcement on "Federal-Provincial Cooperation Modernizing Liability for Offshore Petroleum Drilling Operators".

In the background section of the Draft Guidelines, the NEB discusses the actions that an applicant would undertake to reduce the likelihood of a worst case scenario ("severe event") occurring and its consequences. Actions to respond to an event are also discussed. However, the Draft Guidelines are silent on how this information, which reduces the risk of potential consequences, is considered in determining the unfettered funds that the NEB requires an applicant to provide. The federal government in its backgrounder on the "Federal-Provincial Cooperation Modernizing Liability for Offshore Petroleum Drilling Operators" highlights provision for the absolute liability limit and the financial deposit (unfettered funds) to be reduced to reflect cases of demonstrably lower risk.

ConocoPhillips recommends that the NEB, applying the approach to identification of the worst case scenario outlined in the previous section, address the concern just noted by clarifying in Section 3, Required Cost Information, of the Draft Guidelines, that the steps outlined in that section under the headings:

1. Cost of Containing the Incident
2. Cost of Cleaning-up the Environment
3. Cost of Compensation

would apply only where a residual risk is ranked Medium to High. In addition, in developing all of those sections, the NEB should explicitly recognize and harmonize with existing, similar requirements under other applicable legislation.

The need for harmonization with other security requirements should also be recognized through providing information on how the NEB will manage the:

1. potential overlap of its security requirements, particularly for unfettered funds, with those of other regulators for the same activities, particularly for the onshore, and
2. adjudication of claims potentially made to multiple regulatory authorities by those who may suffer losses from an event.

These are critical issues for applicants and stakeholders for potential projects.

In addition, in the interests of completeness, transparency and fairness, the Draft Guidelines should clearly set out the NEB's policies on the handling and return of

financial instruments, especially letters of credit. A case by case approach is extremely problematic for companies in making their investment decisions, given the size of the financial instruments required.

In respect of other financial instruments discussed under subsection 6 iii) of the Draft Guidelines, ConocoPhillips recommends the inclusion of:

1. Self- Insurance: Self-insurance should be allowed as a method for meeting financial responsibility. For example, ConocoPhillips is larger than most insurers and has net assets with a carrying value of $47.9 billion at December 31, 2012 as audited by Ernst & Young LLP. The NEB could include a stipulation that a company is able to self-insure as long as the company has net assets greater than a certain level and an investment grade paper.

2. Surety Bonds: As set out in the U.S. Code of Federal Regulations Title 30: Mineral Resources, 553.20, surety bonds are accepted by the Bureau of Ocean Energy Management (BOEM) as a means of demonstrating oil spill financial responsibility. BOEM has expressed the view that there is more consistency with bonds and bonds are easier to monitor and offer better protection, as the surety will often perform the work versus writing a cheque. We note as well that section 27(2) of the COGOA expressly references indemnity bonds. For well qualified accounts such as ConocoPhillips, the surety industry will likely consider bonds for guaranteeing clean-up and remediation. Surety bonds will not likely cover compensation costs related to clean-up and remediation.

Unprecedented or Unnecessary Requirements

The Draft Guidelines set out proposed examples of compliance and requirements for which there is no clear goal or need identified. Several of these would, in ConocoPhillips' submission, impose unnecessary administrative and regulatory burdens. Other requirements do not appear to recognize the financial capabilities of the companies that currently hold resource rights in Canada's North and that have the capacity to finance and conduct exploration and production operations on them. Key examples of these are:

- Section 5. Affirmation of Worst Case Scenario Cost Estimates

  This requirement would be an administrative burden under the *Cabinet Directive for Regulatory Management*. As the cost estimates do not directly relate to management systems, safety, or environmental protection, it is unclear why the NEB would apply an onerous requirement that exceeds the management system requirement to identify a "person accountable" under the *Oil and Gas Drilling and Production Regulations* and to appoint an "accountable officer" under the *Onshore Pipeline Regulations.*

  ConocoPhillips recommends that this requirement be removed. If it is retained, the Draft Guidelines should clarify the unique circumstances under which this requirement would be justified.

- Section 6. To Demonstrate Coverage for Financial Viability

  The requirement for audited financial statements and the prohibition on the use or parent company financials is exceptionally problematic for some companies. Subsection 6. iii) Audited Financial Statements allows for the use of parent company financials if the parent company provided a guarantee. The requirement for ConocoPhillips Canada to provide audited financials is a major issue since ConocoPhillips Canada is not separately traded from its parent and separate audited financials are not prepared. Furthermore, ConocoPhillips Canada financial information is prepared using U.S. generally accepted accounting standards because it is a component of the parent company financial statements published annually.

  ConocoPhillips recommends that the use of parent company financials where the parent company provides a guarantee be accepted to demonstrate coverage for both financial viability and financial responsibility.

- 6 ii) Insurance

  - The estimated time required before payout occurs

    There are too many variables to accurately identify a time required before payout occurs. Typically, the insured pays the loss; then, after it is reasonably confident that all costs have been confirmed , a claim is submitted to the insurer. Adjusters then go through the documents submitted by the insured to verify the claim/expenses. Once the adjustment process is completed, a proof of loss is submitted to the insurer and the adjusted claim is payable pursuant to the Payment of Loss section of the policies.

    ConocoPhillips recomends that this requirement be removed, as there is no way to know in advance when insurers will pay.

  - The Board will be notified at least 60 days in advance if insurance will be cancelled or changed

    The standard notification in insurance policies is 30 days.

    ConocoPhillips recommends that the requirement be removed. If it is retained, it should be reduced to 14 days. Further, notice should only be required if the insurance is to be cancelled or materially changed.

  - The listing of all exclusions

ConocoPhillips recommends that this requirement be removed, as it is without precedent in Canada and internationally.

- <u>A review of all the combined insurance policies must be provided by an independent third party</u>

  It is unclear what third party the NEB would expect to be qualified to conduct this review. Further, given ConocoPhillips in-house expertise in this area and the clear importance to ConocoPhillips as insured of contracting with viable insurers, it is unclear how a review by any other party would add assurance to the NEB regarding the strength of any combined insurance policies.

  ConocoPhillips recommends that this requirement be removed as it is without precedent in Canada and internationally.

ConocoPhillips trusts this information will be of assistance in the review of the Draft Guidelines. If you have any questions on the submission, please feel free to contact me at 403-233-3139, or contact Scott Gedak at 403-260-2011.

Yours truly,

CONOCOPHILLIPS CANADA RESOURCES CORP.

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