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
4/13/2011
641180

Submission Methodology

Chevron Canada Limited ("Chevron") submitted its *AODR Submission Part 1: Briefing Document* to the National Energy Board ("NEB") on 1 April 2011. This document is *Part 2: Responses to NEB Calls for Information 1 and 2* and completes Chevron's submission to the NEB's Public Review of Arctic Safety and Environmental Offshore Drilling Requirements.

The sequence of responses within this submission follows the sequence of requests within Calls for Information 1 and 2. Where appropriate, cross-references have been added within provided responses to best include common elements between requests while minimizing duplication of text.

Call for Information 1: pages 2 – 69

Call for Information 2: pages 70 - 87

Call for Information No. 1

SCOPE ITEM #1 – POTENTIAL HAZARDS AND RISKS ASSOCIATED WITH ARCTIC OFFSHORE DRILLING, INCLUDING THREATS TO PUBLIC SAFETY, WORKER SAFETY AND THE ENVIRONMENT

1.1.1 *Management System*

Context: A management system is a systematic approach designed to identify, manage and reduce risks associated with a work or activity, including safety (e.g. public safety, worker safety, process safety, asset integrity) and environmental protection. It includes the necessary organizational structures, resources, accountabilities, policies and procedures to achieve that objective. Subsection 5(1) of the *Canada Oil and Gas Drilling and Production Regulations* (Drilling and Production Regulations) states:

> The applicant for an authorization shall develop an effective management system that integrates operations and technical systems with the management of financial and human resources to ensure compliance with the Act [*Canada Oil and Gas Operations Act* (COGOA)] and these Regulations.

Section 18 of the Drilling and Production Regulations requires that an operator (who is by definition the holder of the authorization) ensure that the management system in section 5 is implemented.

Request:

(a) How should a company prepare/intend to employ an effective management system that integrates operations and technical systems with the management of financial and human resources to ensure compliance with COGOA and the Drilling and Production Regulations, in the unique Arctic environment?

(b) Please discuss how a management system should be applied during each project phase (e.g. planning, design, commissioning, drilling, suspension, abandonment).

Responses to 1.1.1 (a) and 1.1.1 (b):

Chevron supports the responses provided by the Canadian Association of Petroleum Producers (“CAPP”) in this regard.

1.1.2 *Management System*

Context: Paragraph 5(2)(c) of the Drilling and Production Regulations requires that the management system include processes for identifying hazards and for evaluating and managing the associated risks. Subsection 5(4) of the Drilling and Production Regulations requires that the management system correspond to the size, nature and complexity of the operations and activities, hazards and risks associated with the operations. Paragraph 5(2)(f) of the Drilling and Production Regulations requires that the management system contain processes for internal reporting and analysis of hazards, minor injuries, incidents and near-misses and for taking corrective actions to prevent their recurrence.

Request:
(a) Describe the decision-making processes and basis for determining when risk assessments are conducted.
(b) Describe the internal structures, with accountabilities and responsibilities, for ensuring that required mitigation from risk assessments would be implemented in a timely fashion and that the actions taken achieve their original intent in the unique Arctic environment.
(c) Describe the process of hazard identification and risk assessment in the unique Arctic environment. What methods would be used? Identify any standards or guidelines that could be applicable to offshore drilling.
(d) Describe how a company prevents, detects, manages and mitigates hazards and the related risks associated with Arctic offshore drilling projects (from planning through abandonment).
(e) Describe how frequency and consequences of hazards [events] are determined and how risks are evaluated.
(f) How are risks for low frequency – high consequence events judged? What is the basis for deeming risks acceptable – particularly those associated with high consequence events?

Responses to 1.1.2 (a) to (f):

The Chevron Management System is known as the Operational Excellence Management System (OEMS) and it is a critical driver for business success and a key part of our enterprise execution strategy. Operational Excellence is defined as “the systematic management of process safety, personal safety and health, environment, reliability and efficiency to achieve world-class performance.”

Objectives of the OEMS are to:

- Achieve an incident- and injury-free workplace.
- Promote a healthy workforce and mitigate significant workplace health risks.
- Identify and mitigate environmental and process safety risks.
- Operate with industry-leading asset integrity and reliability.
- Efficiently use natural resources and assets.

As part of OEMS, Chevron has a standard corporate process for Risk Management. The purpose of the risk management process is to systematically and consistently identify and address health, environment, safety and asset risks related to all facilities and activities under Chevron operational control.

The objectives of the risk management process are to:

- Apply a standardized health, environment and safety (HES) risk assessment procedure across all Chevron facilities and activities to assess HES risks
- Periodically revalidate and maintain HES risk assessments
- Achieve closure of all identified HES risk-reduction action items
- Demonstrate continual improvement in the management of HES risks

Risk Management Process

The Risk Management Process contains an integrated set of tools used to identify, evaluate and take action on HES and certain asset risks. It is designed to help Management and Project Teams manage existing facility, activity and new project risks, logically and consistently. The Risk Management Process applies to drilling and completions activities.

Using the Risk Management hazard identification procedure enables proactive assessment of HES risks and guides management into determining appropriate risk reduction. The Risk Management hazard identification procedure is designed to incorporate enterprise best practices, lessons learned and external benchmarking as well as it aligns with ISO 14001 (Environmental Management System).

As part of this process Chevron has trained and qualified numerous risk practitioners. Critical to this process is to include the right people to conduct initial assessments of all of our worldwide operations. Chevron has formed a HES Risk Management Center of Excellence to provide centralized support of the HES Risk Management Process. The HES Risk Management Center of Excellence has oversight of and coordinates:

- Implementation and sustainability of the corporate HES Risk Management Process
- HES Risk Management organizational capability (resources, training, qualification etc)
- HES Risk Management Communities of Practice
- Risk Management procedures and tools and updates
- HES Risk Management quality assurance assistance

The Risk Management process follows a 5 step approach:

1. Sub-Procedure 1: Identify, Group and Prioritize
2. Sub-Procedure 2: Perform High Level Risk Assessment to Identify HES Risks and Determine Further Risk assessment needs
3. Sub-Procedure 3: Perform Targeted Detailed Risk Assessments
4. Sub-Procedure 4: Develop Risk Reduction Plan and Document Closure of Actions
5. Sub-Procedure 5: Periodically Revalidate Procedure

As part of Sub-Procedure 2, Chevron has established risk criteria for use in comprehensive risk assessments applied to existing facilities and new projects where there was a potential for a major accident. This business process is key to identifying and avoiding catastrophic events. Risk is based on the consequence and likelihood of an event. The key to effective risk assessments are in the answers to these questions:

- "What can go wrong?
- "What are the potential consequences?
- "What safeguards are in place and how reliable are they"?
- "What is the likelihood of the consequences occurring, given the safeguards in place?
- And finally, "What risk mitigation, if any, is needed"?

Risk and Uncertainty Management Standard (RUMS)

In Chevron's drilling operations, Chevron also has a specific process to address Risk and Uncertainty Management for the Subsurface (RUMS). This process is accompanied by a management of change process for our subsurface well designs.

RUMS is a process designed to ensure that technical, operational, HES and financial risks and uncertainties are identified and appropriately mitigated and managed. The objectives of this Standard include:

- Systematically and explicitly identifying key uncertainties and associated risks for a given project/well.

- Defining a risk and uncertainty assessment process that will be useful for optimizing well design alternatives and effectively avoiding, mitigating and managing risks.
- Applying risk and uncertainty management during well execution to ensure that the Value Based Well Objectives (VBWO) are achieved.
- Establishment of a risk assessment process that can be used in conjunction with the Management of Change (MOC) process to determine the acceptable level of risk under which the well can proceed.

The RUMS procedure requires a risk assessment be conducted on each offshore project or well. The risk assessment is conducted by multifunctional teams who are required to ensure that risk assessment recommendations are followed and have been closed out. The RUMS procedure establishes roles and responsibilities for visible leadership engagement and commitment to the procedure.

At the time Chevron commences planning an Arctic drilling program we would apply our Risk Management Process and RUMS taking into account the specific drilling program being planned and the unique challenges associated with the Arctic.

1.1.3 *Safety Culture*

Context: The successful implementation of a management system depends upon the actions of people within the organization. A company's safety culture may be defined as the product of individual and group values, attitudes, competencies and patterns of behavior that determine the level of commitment, the style and overall effectiveness of a company's safety oriented programs.

Request:

(a) Describe the commitments, policies, practices, and programs that support continuous improvement of a safety culture.

(b) How would you demonstrate that the current state of your organization's safety culture is appropriate for Arctic offshore activities?

Response to 1.1.3 (a):

Chevron supports the response provided by CAPP in this regard.

Response to 1.1.3 (b):

Chevron's vision is "to be recognized and admired by industry and the communities in which we operate as world-class in process safety, personal safety & health, environment, reliability and efficiency." Chevron is committed to the health and safety of our employees and contractors; and to continuing to work with the responsible departments and agencies in Canada to find ways to improve the safety and reliability of offshore oil and gas operations in Canada (refer to Section 1.1.2).

Chevron has developed a set of 10 Tenets of Operation, providing a foundation for establishing a culture of Operational Excellence (OE) at Chevron, that have been adopted as a fundamental "Code of Conduct" for our workforce's daily behavior that employees and contractor use and that supervisors and managers reinforce. They are a behavioral top ten list of lessons learned from incidents reviews. These Tenets emphasize high risk areas of our business. When not operating (behaving) in accordance to these Tenets, the probability of an event is increased.

The Tenets of Operation are based on two key Principles:

- Do it safely or not at all.
- There is always time to do it right.

The Ten Tenets of Operation are:

1. Always operate within design and environmental limits.
2. Always operate in a safe and controlled condition.
3. Always ensure safety devices are in place and functioning.
4. Always follow safe work practices and procedures.
5. Always meet or exceed customer's requirements.
6. Always maintain integrity of dedicated systems.
7. Always comply with all applicable rules and regulations.
8. Always address abnormal conditions.
9. Always follow written procedures for high risk or unusual situations.
10. Always involve the right people in decisions that affect procedures and equipment.

While the entire workforce is accountable for delivering OE performance, leadership is the single largest factor for success in OE. Leaders establish the vision and set objectives that challenge the organization to achieve world-class results. They direct the Management System Process, setting priorities and monitoring progress on plans that focus on the highest-impact items. Leaders visibly demonstrate their commitment through personal engagement with the workforce and by showing concern for the health and safety of every individual. They demonstrate the same commitment to protecting the environment and process safety risk mitigation. Leaders continually improve our OE culture by understanding the gaps and removing barriers to world-class OE performance. Leaders play an important role in setting expectations and reinforcing behaviors consistent with the Principles and Tenets.

Supplementing the key principles and Tenets is Stop Work Authority where all personnel are authorized with the responsibility of stopping any work that the worker is unsure about or feels may not be safe to continue, or poses a risk to the environment. Chevron's philosophy is that the health and safety of our workforce and the protection of the natural environment is a fundamental company value. This is in keeping with Canadian OH&S Act 45 (1)(a), 46 – The right to refuse unsafe Work. Communicating and reinforcing the expectations of Stop Work Authority and the Tenets of Operation is a critical component of project planning and execution including incorporating them into daily task planning meetings during operations.

Other operational preparations include management-led Incident Free Operations workshops attended by key onshore and offshore Chevron staff, service providers and the drilling contractor to ensure alignment of all parties around Chevron's core values of safety and environmental stewardship and setting out clear expectations around incident free operations, stakeholder engagement, communications and continuous improvement. It also ensures familiarization with our Key Principles, our Tenets of Operation and Stop Work Authority.

Chevron's Recent Lona O-55 well

The following example illustrates the recent application of Chevron's culture of Operational Excellence to a recent Canadian deepwater offshore drilling program. Chevron drilled the Lona O-55 exploration well approximately 430 kilometres northeast of St. John's, Newfoundland and Labrador, in a water depth of 2,600 metres between May and September of 2010. This was Chevron's second well in the Orphan Basin. Chevron implemented a number of OE components into this well program to ensure safe and incident-free operations, some of which include:

- As a part of our Operational Excellence program, Chevron evaluates the safety systems and safety cultures in place with every key company we work with. If a contractor does not meet our standards, we will not work with them. Prior to drilling Chevron's Lona O-55 well, we assessed all of our key Contractors to ensure they could meet our internal standards. If a Contractor could not meet our standards, they were not used.
- From February 8-10, 2010, Chevron management hosted a three-day safety leadership workshop in St. John's to reinforce Chevron's emphasis on conducting safe operations, involving all Orphan Basin project contractors, and observed by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).
- In April, Chevron held a Risk Assessment meeting facilitated by external peers from another Chevron deepwater drilling organization to review step-by-step well design and contingencies.
- On May 1st, prior to commencing operations and after taking possession of the drill ship, Chevron conducted two, seven-hour safety sessions, one for each of two crews on board the drill ship to deliver Chevron's commitment to an incident-free operation.
- During the drilling program we worked closely with the Rig Contractor to support and reinforce their safe operations, by providing our own HES Representatives onsite to work alongside the Rig Contractor's

safety staff. By working closely with the Rig Contractor, we achieved results that met both Chevron's and the Rig Contractors objectives.

- Prior to drilling into the potential hydrocarbon zone, Chevron conducted a second Emergency Response exercise to ensure that all the emergency protocols were in place and functioning. The C-NLOPB was a witness to this exercise.
- Near to the end of our well, we shut down the rig for 12 hours for a Safety Stand Up, and reinforce Chevron's safety principles and remind everyone not to be complacent towards the end of the well. We also took the opportunity for everyone to give us their feedback on how Chevron and our Rig Contractor performed with regards to safety.

These examples are only part of an extensive suite of measures designed to ensure that all parties involved in drilling planning and operations are fully aligned; that there are clearly defined roles and responsibilities; that risks are identified and appropriate control or mitigation plans are in place; that people are trained and competent, and that Chevron's core values of safety and environmental protection and expectations around incident free operations are understood and embraced.

Chevron would apply its safety culture, OEMS, Tenets of Operation and Incident Free Operation approach to any wells it drills within the Canadian Beaufort.

1.1.4 *Training and Competency*

Context: Trained and competent personnel are a key contributor to the prevention of incidents and response to incidents. The existing regulatory framework includes several requirements related to training and competency. COGOA requires an applicant for authorization to declare that the personnel to be employed in respect of equipment and installations are qualified and competent for their employment, and that personnel continue to be so qualified and competent for the duration of the authorized work or activity. The Drilling and Production Regulations require in:

- paragraph 19(1) that a sufficient number of trained and competent individuals are available to complete the authorized work or activities and to carry out any work or activity safely and without pollution;
- section 5, that the applicant's management system contain processes for ensuring that personnel are trained and competent to perform their duties (5 (2)(d)) and that there are arrangements for coordinating the management and operations of the proposed work or activity among the owner of the installation, the contractors, the operator and others, as applicable (5(2)(j)); and
- paragraph 72(a), that all personnel have, before assuming their duties, the necessary experience, training and qualifications and are able to conduct their duties safely, competently and in compliance with the Drilling and Production Regulations.

Request:
(a) Describe how the appropriate training and competencies would be identified for the positions needed for a drilling work or activity, from the planning phases through operations and abandonment. Describe the process for ensuring that personnel are trained and competent to perform their duties.
(b) Describe the arrangements that would be necessary between the holder of the authorization and others, such as the owner of the installation, contractors etc., to ensure that all personnel would be trained and competent for their duties and that an adequate number of personnel would be available.

Responses to 1.1.4 (a) and 1.1.4 (b):

Chevron supports the responses provided by CAPP in this regard.

1.1.5 *Accountabilities and Responsibilities*

Context: Under COGOA, the holder of the authorization (the operator) is responsible for ensuring that it carries out its work and activities in compliance with COGOA, the applicable regulations and the conditions set out in the approval/authorization. The purpose of the management system, as set out in subsection 5(1) of the Drilling and Production Regulations, is to ensure compliance with COGOA and those Regulations. Paragraph 5(2)(k) of the Drilling and Production Regulations requires that the management system contain the name and position of both the person accountable for the establishment and maintenance of the system and the person responsible for implementing it. Section 19 of the Drilling and Production Regulations requires that the operator take all reasonable precautions to ensure safety and environmental protection.

Request:

(a) Describe how the processes, accountabilities and responsibilities and arrangements in the management system would be used to achieve regulatory compliance, in the unique Arctic environment, including the requirements set out in section 19 of the Drilling and Production Regulations.

(b) What factors are considered in determining reasonableness?

Response to 1.1.5 (a):

Chevron supports the response provided by CAPP in this regard.

Response to 1.1.5 (b):

Chevron supports the response provided by CAPP in this regard. For additional discussion on determining reasonableness and application of the ALARP Principle *(As Low As Reasonably Practical)*, please refer to the *Chevron Canada Resources AODR Submission Part 1: Briefing Document,* and Section 1.5.1(c).

1.1.6 *Coordination of Activity*

Context: There are often several companies involved in an offshore drilling project, including the operator, a certifying authority, an owner of the installation and contractors. Under COGOA, the operator is responsible for ensuring that the work or activity is carried out in compliance with COGOA, the applicable regulations and the conditions set out in the approval/authorization. Paragraph 5(2)(j) of the Drilling and Production Regulations requires that the management system include the arrangements for coordinating the management and operations of the proposed work or activity among the owner of the installation, the contractors, the operator and others, as applicable.

Request:
(a) For an Arctic offshore drilling project, identify the various types of companies that would be involved from planning through abandonment, their roles and the timing of their participation.
(b) Describe the arrangements, including control, freedom to act, oversight and communications, that would be necessary between an operator and its contractors to ensure that work or activities carried out by others are in compliance with COGOA, the applicable regulations, and the conditions set out in the approval/authorization.

Response to 1.1.6 (a):

In addition to the Operator, many companies are involved in the drilling and abandonment of an offshore well. As an example, for Chevron's most recent deepwater well offshore Newfoundland and Labrador, Lona O-55, Chevron had over 100 contracts in place for various supplies and services. Some examples of such commonly contracted services include, but are not limited to:

- Rig supplier and operator – Supplies the Canadian Certified drilling rig vessel (Mobile Offshore Drilling Unit (MODU) or fixed platform rig) and the majority of the drilling equipment and personnel. Personnel will be trained to comply with all company and regulatory directives and policies relevant to operations in Arctic offshore environments
- Ice management fleet – Provides Canadian Certified ice class vessels and trained personnel to manage ice and perform support functions for each stage of the project.
- Drilling Fluid Services – Provides experienced personnel to design environmentally compatible drilling fluid systems to ensure safe and efficient drilling of each well. All products are screened for quality and efficacy.
- Cementing services – Provides cement and technical services associated with casing cementing and plugbacks. Only cementing companies with arctic experience and cold service products would be contracted.
- Directional Drilling Services – Provides downhole tools and personnel to plan and execute any directional drilling on the well.
- Logging and formation evaluation – Provides logging equipment, tools and trained personnel for logging and formation evaluation.
- Specialized equipment and tubular goods suppliers – Where specialized equipment or drilling operations are needed, specific service providers have tools and personnel on board to provide support.
- Aviation and transportation – Provides logistical support in moving personnel and supplies. Equipment and personnel to be trained and certified to operate in arctic conditions.
- Subsea Wellhead – Provides the hardware and personnel to service the hardware installations during the various stages of well construction.
- Coring – Provides the hardware and personnel to run the coring operation to recover samples of rock.
- Supply base – Vendor provides the facility and personnel to manage transportation of materials and people to and from the well location.
- ROV – Provides the remote operated vehicle(s) for subsea dive work and the personnel to operate the equipment.
- Solids controls and waste disposal – Provides the processing equipment and containers to separate solids from the drilling fluid along with the personnel to operate the units and to dispose of it as required.

- Spill equipment – Provides the booms, absorbent materials, spill lockers and first response personnel to operate the equipment in the event of a spill.

Support service contractors include, but are not limited to:

- Safety and medical services – Monitors safety programs and compliance, reports on safety statistics and incidents.
- Logistics and communications – Provides data and communication services for remote monitoring and operations support.
- Environmental monitoring – Provides observers and monitors associated with environmental studies and operations.
- Fuel – Provides fuel supply, storage and safe handling.
- Catering services – Supplies the rig personnel with food preparation and housekeeping services.

Exploration wells will be suspended or abandoned after drilling and evaluating the well, which will require additional support services.

Response to 1.1.6 (b):

Chevron supports the philosophy provided by the CAPP response in this regard. In addition, Chevron incorporates the philosophy into our operations by establishing the project management system, regulatory compliance requirements and responsibilities in various plans including the Safety Plan, Environmental Protection Plan, and Emergency Response plan. The contractor's work processes and procedures related to each plan are reviewed to ensure they meet Chevron's standards and the regulatory objectives, and to identify and rectify any gaps identified before work begins. Clearly, establishing respective levels of and responsibilities for control, freedom to act, oversight and communications is a key part of this planning process with contactors. The resulting arrangements are formalized in Bridging Documents which are signed off with each major contractor to ensure all parties are aware of, agree with and are prepared to take ownership of their portions of these arrangements. The various Plans are submitted to the regulator for review during the operations authorization process.

A number of steps are taken to assure the Management Plans and Bridging Plans commitments are followed through. The commitments made, including the regulatory requirements, are itemized, assigned, and communicated well ahead of beginning any operations. Some of the actions taken before and during operations with contractors to assure alignment on expectations, roles and responsibilities and compliance with regulatory requirements on Chevron's Lona O-55 deepwater exploration well were summarized in the response provided in 1.1.3(b).

Control systems are put in place to assure the commitments are met, and a combination of supervision, leadership visits, metrics tracking, inspections, and audits are used to verify the commitments are being met throughout the operation. The regulator will typically conduct its own monitoring, inspections and audits to confirm the operator's plans are being implemented as written, and to verify compliance with applicable regulations is being achieved.

SCOPE ITEM #4 – EFFECTIVENESS AND RELIABILITY OF AVAILABLE WELL CONTROL METHODS, INCLUDING CONSIDERATION OF EMERGING TECHNOLOGIES

1.4.1 *Well Control*

Context: Maintaining control of a well is essential for safety and protection of the environment. The issue of well control is of particular interest in relation to Arctic offshore drilling. Section 36 of the Drilling and Production Regulations states, in part, that:

> (1) The operator shall ensure that, during all well operations, reliably operating well control equipment is installed to control kicks, prevent blow-outs and safely carry out all well activities and operations, including drilling, completion and workover operations.
>
> (2) After setting the surface casing, the operator shall ensure that at least two independent and tested well barriers are in place during all well operations.
>
> (3) If a barrier fails, the operator shall ensure that no other activities, other than those intended to restore or replace the barrier, take place in the well.

In the Drilling and Production Regulations, a 'barrier' means any fluid, plug or seal that prevents gas or oil or any other fluid from flowing unintentionally from a well or from one formation into another formation. 'Well control' means the control of movement of fluids into or from a well. 'Fluid' means gas, liquid or a combination of the two. "Well operation" means the operation of drilling, completion, recompletion, intervention, re-entry, workover, suspension or abandonment of a well. The Arctic is a unique environment that would require additional safety and well control features and enhanced reliability of well control system for a successful drilling operation. New technology and innovative approaches may be needed to face the challenges of the Arctic offshore drilling environment.

Request:

(a) Describe the various types of barriers, as defined in the Drilling and Production Regulations that can be used during well operations, including drilling, completion and workover operations. Discuss the applicability and effectiveness, including the benefits and limitations of using these barriers in an Arctic environment.

(b) Describe the various types of available and emerging well control technologies that can be used during well operations.

(c) Provide a discussion of redundancy in relation to well control, including what it provides and how it is achieved.

(d) Discuss the applicability, effectiveness and reliability of well control equipment in an Arctic offshore environment, including how Arctic offshore drilling conditions are simulated while testing well control equipment.

(e) Describe the available and emerging well monitoring and detection technologies that could be applicable in the Arctic offshore drilling environment.

(f) Discuss how a company would determine that sufficient well control barriers would be in place for the life of a well to prevent well control failure, including during drilling with only a diverter system, drilling with a blow-out preventer, and while using a wireline.

(g) How would a company address the risk of a blow-out outside of the well casing? Also please provide a discussion of the methods and processes that would be used to verify the effectiveness of the annulus barriers.

(h) How would training and competency requirements be determined for well control related positions, including the competency assurance process?

Responses to 1.4.1 (a) and 1.4.1 (b):

Well control technologies are applied both in the prevention of loss of well control and after a kick. Barrier management is key to well control. The use of a particular well control method depends on the operational condition of the well and the effectiveness of the method in that situation. Re-establishment of a primary and/or secondary barrier is the objective of the well control method.

Hydrostatic control using weighted fluid is the primary barrier while drilling. In the event of a kick or uncontrolled flow, higher density fluid is placed into the wellbore by either circulation (preferred) or bull heading where wellbore fluids are forced back into the flowing formation.

Mechanical barriers can be implemented which will separate the source of potential flow from the drilling rig. Examples of mechanical barriers include casing, cement, packers and plugs, which may be placed in the well at desired intervals to segregate pressure and fluid sources.

Mechanical well control devices include Blow Out Preventers (BOP) which terminate flow from the pipe, well bore, or annular space using rams and sealing elements.

These are proven barriers and well control methods for floating drilling operations. In general, Arctic offshore drilling does not alter the applicability or effectiveness of these proven methods, as unique subsea characteristics, such as permafrost are managed as outlined in Section 1.5.1(a) and 1.5.1(b). As discussed in the Briefing Document, unique attributes of Arctic offshore drilling that can potentially have an impact on well control operations are vessel station-keeping, planned disconnects and late season disconnects. These challenges will be addressed the risk assessment of any future drilling program, and through the associated Ice Alert procedures.

Although previous drilling programs have demonstrated industry can safely drill in the Arctic offshore while protecting the environment, Chevron and industry continue efforts to enhance this performance. This includes new technologies being developed in BOPs to enhance well control capability and redundancy. Chevron, is actively jointly developing an Alternative Well Kill System (AWKS) with Cameron International, which is an enhanced BOP system designed to simultaneously shear and seal on an increased range of drilling tubular and casing, while also providing a redundant simultaneous shear-seal BOP (refer to *Chevron Canada Resources AODR Submission Part 1: Briefing Document)*. Also under development for use in the Gulf of Mexico is a purpose built secondary capping mechanism for potential deployment in the event of a subsea well blowout.

In relation to emerging well control technologies, Chevron supports the response provided by CAPP in this regard.

Response to 1.4.1 (c):

Redundancy is built into the well control systems in terms of equipment and well integrity management. For well integrity, the well configuration at each step of the drilling, completion, and abandonment process is examined for redundancy in well barriers. The relationship of the well control barriers is considered when developing the well design, and redundancy is maintained at all times during normal operation. Contingency planning for the loss of one barrier is considered, and procedures are developed to correct the situation at each stage.

For individual well control devices that are critical safety systems, there will be redundancy built into the equipment to ensure operation. For example the BOP has multiple methods of activation:

1. Manual- a manual switch is located in the rig control room and the toolpusher’s office
2. Deadman – triggers upon loss of control signal, loss of power from the rig or upon an unplanned riser disconnect
3. Remote Operated Vehicle (ROV) - an ROV activates the BOP via a hydraulic hot stab and by pumping hydraulic fluid
4. Acoustic – a sound signal is transmitted from the rig, a marine vessel or ROV to trigger the BOP control module.

The activation systems have full redundancy for power sources and control modules. The BOP itself is designed as a redundant system with duplicate shear rams and multiple annular preventers capable of shutting in a well regardless of the well operation and tubular configuration. Deepwater wells in the Arctic will carry a spare BOP to guard against the case where it may not be possible to retrieve the main BOP stack due to poor ice conditions.

Response to 1.4.1 (d):

While the met-ocean conditions in the Arctic are significantly different than the Gulf of Mexico, the subsea conditions in deepwater environments are very similar for temperature and pressure. Subea well control equipment for deepwater operations can be expected to meet the required conditions for the Arctic offshore and function reliably under these conditions. Any well control equipment on the floating drilling unit would be designed for the ambient temperatures, and would consider equipment location, enclosures, heat management, and freeze protection.

Response to 1.4.1 (e):

Measurement and monitoring are part of the Chevron OE management process to ensure both efficient operation and hazard identification. All projects undergo a hazard identification and assessment evaluation which identifies the necessary monitoring processes and tools for safe operation. As stated previously, the Arctic does not introduce any subsurface drilling operations that are different relative to other floating drilling operations, so all of the normal well monitoring and detection systems would be used. When supported by the appropriate equipment maintenance programs, training and competencies programs and well control procedures, these systems are accurate and reliable.

Many of the existing monitoring systems are automated for trending and alarm to detect unusual operating conditions. Existing well monitoring systems include: surface mud volume and circulation measurement, fluid pressures on string and well annuli, and mud weight and gas content. Downhole measurement of formation parameters (logging while drilling) also provides information on well geological conditions. Pore pressures can be inferred from log analysis, measured from reservoir in situ logs, and lastly, during drilling in some circumstances, to calibrate geological models. Directional hole measurements while drilling ensure the well subsurface location is on target.

Emerging well monitoring systems include the use of remote real time data transmission to a central site to improve communication and collaborative problem solving of operational issues. Other technologies being developed by service companies, such as downhole seismic, will be evaluated at the time of well drilling.

Response to 1.4.1 (f):

Chevron has standard Corporate Well Control Policies that governs the design and use of well control equipment and procedures. Deviation from this policy must be justified through the robust OE Management of Change (MOC) process, which includes a Subsurface Management of Change standard. Deviations require that sound engineering judgment be documented, risks identified and mitigated, and management approval granted before being implemented.

Critical well designs go through a peer review process for all phases. Chevron conducts internal peer assists during the planning phase of all our wells. This formal approach to reviewing well design and execution of drilling, completion and abandonment is carried out by subsurface, drilling and completion professionals not associated with the project to ensure objective review.

During the life of a well there are three phases of well control application. At the time the well is designed, the barriers and casing setting depths are determined. Geological parameters are monitored during drilling to evaluate well integrity and the configuration of the well can be modified if required. A diverter is part of the riser system when drilling with a subsea BOP system. It is used to divert gas from the rig floor should gas inadvertently enter the riser prior to closure of the BOPs and is not considered a well control device.

The first phase of the well drilling is to set the conductor and surface casing. Shallow hazard data is assessed using high resolution 3D seismic or dedicated shallow geohazard surveys and the top hole location selected to avoid them.

After the surface casing is set, the BOP is secured to the wellhead and rotary drilling is used from this depth onward. All operations from this point will have two barriers in place. As a minimum, there will be the hydrostatic fluid control and the BOP. Intermediate casing strings are cemented in place to isolate uphole formations and manage the mud weight against formation fracture pressure. During wireline logging the well is in a stable condition with full hydrostatic control plus the BOP is capable of cutting the wireline and sealing the well. The open hole section is then plugged back with cement or the final casing string is cemented in place. Cased hole production testing may be performed through tubing to testing facilities.

When the well is permanently abandoned, cement plugs and mechanical packers isolate zones of potential flow. The casing strings and barriers are tested for integrity. Kill weight fluid is left in the wellbore between the mechanical barriers, and a corrosion cap is left to protect the top of the wellhead at mudline.

Corporate policy requires that barrier integrity is maintained through the stages of the well life by correct design, testing and maintenance. When there is the potential for flow, two or more barriers are in place to insure well integrity.

Response to 1.4.1 (g):

Blowouts that occur outside of casing are caused by failure of barriers. Well integrity for the annular space between the casing or liner and the borehole is managed in the same way as barriers for wellhead integrity. At the well design stage the casing strings, mechanical seals, and cement placement are configured such that each barrier can be reliably installed and tested. Exploratory wells will have a sufficient safety factor to allow for all anticipated conditions. Development wells have the benefit of known conditions and are designed for the producing life of the field. Operational safeguards are put in place to monitor and prevent casing wear while drilling and tripping. Should wear occur, additional casing strings are available for installation.

Cementing programs are monitored for quality assurance on slurry design and actual cement properties in the field. Program data is recorded to verify that cement placement is according to design. Annular barriers are tested at each installation stage to ensure reliability. Pressure tests are performed, and cement bond logs can be run for verification of well integrity. Chevron has an in-house cement lab for quality control and cement testing.

Response to 1.4.1 (h):

Well control training standards are set by industry committees and regulatory statutes, establishing competency requirements. Chevron requires continuous training and the certifications necessary for qualified drilling personnel. Certification covers procedures to manage unusual circumstances and the means to verify that contractors involved in drilling wells possess the skills necessary to execute well control.

Chevron Well Supervisors are required to satisfactorily complete an International Association of Drilling Contractors (IADC) WellCap Course each 2 years as a condition of employment, in addition to any regulatory required courses. Well Control certifications are required by Chevron for all offshore positions of driller and higher. Competency assurance is accomplished via auditing training records of the contract drilling personnel. On-the-job competency is maintained through performance evaluation of rig crews during well control drills, trip drills and choke drills. Chevron also operates an in-house well control school for training of employees worldwide. These training programs meet or exceed American Petroleum Institute's recommendations for well control and conform to the IADC's WellCAP criteria.

Chevron provides its own, in-house well control training to ensure that everyone within our drilling operations is proven competent against the same high standards. Our philosophy is that well control is at the very heart of well design.

SCOPE ITEM #5 – STATE OF PREPAREDNESS TO RESPOND TO DRILLING ACCIDENTS, SPILLS AND MALFUNCTIONS, INCLUDING CONSIDERATION OF CONTINGENCY PLANNING REQUIREMENTS, EMERGENCY RESPONSE PLANNING REQUIREMENTS, INFRASTRUCTURE, EQUIPMENT, SUPPLIES AND TRAINING NEEDS

1.5.1 *State of Preparedness*

Context: The Gulf of Mexico BP Deepwater Horizon well accident and spill occurred in 2010, where well control measures reportedly failed (nature of the accident), and resulted in worker deaths and a significant oil spill for up to three months (magnitude of the accident). The Board is calling for available information that addresses the state of industry preparedness in the event of a similar scenario occurring in Canadian Arctic waters. In particular, responses to this call for information should address industry's state of preparedness to respond to drilling accidents and spills, including consideration of contingency planning requirements, emergency response planning requirements, and response infrastructure, equipment, supplies and training needs. Based on offshore oil and gas rights issued by Indian and Northern Affairs Canada since 2007, the oil and gas industry's current interest is focused in the western Arctic in the Beaufort Sea, northwest of Tuktoyaktuk, Northwest Territories. The Exploration Licences issued are along the continental shelf with water depths ranging from about 100 m to over 1000 m. An example of an emerging area of interest in the eastern Arctic is the Davis Strait where two wells were recently drilled in Greenland Arctic waters, east of the Canada-Greenland international boundary. There have been no Exploration Licences issued by Indian and Northern Affairs Canada for this area. The Drilling and Production Regulations require that each applicant for an authorization to drill a well is required to have an effective management system that includes processes to:

- identify hazards;
- evaluate and manage associated risks;
- ensure that personnel are trained and competent to perform their duties; and
- ensure and maintain the integrity of all facilities, structures, installations, support craft and equipment necessary to ensure safety, and environmental protection, and that includes, the arrangements for coordinating the management and operations of the proposed work or activity among the owner of the installation, the contractors, the operator and others, as applicable.

The Drilling and Production Regulations also require that each application for an authorization be accompanied by contingency plans for the proposed work or activity, including emergency response procedures.

Request:

Consider a scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the western Arctic during late summer. Consider a second scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the eastern Arctic area during late summer. Based on the above scenario for the western Arctic, and then separately for the scenario for the eastern Arctic, with references to key supporting reports where appropriate, please provide a description of:

(a) the types of hazards which could result in an accident of this nature and how the risks would be effectively managed to mitigate the impacts;

(b) likelihood of encountering the hazards identified in (a);

(c) the ecosystem, human health, wildlife harvesting, cultural, traditional use and economic valued components and community infrastructure that would likely be at risk from the consequences of the oil, mechanical recovery, chemical dispersion, in situ burning methods and the response and cleanup operations, and how the risks would be effectively managed to mitigate the impacts;

(d) the likely emergency and cleanup response structure, including the command structure and the subsidiary general structure (operations section, planning section, logistics section, etc., or other appropriate structure), the chain of command, and the number of company personnel, government departments and agencies, contract persons, community volunteers and other personnel or volunteers that could be involved in each identified structural section;

(e) the types and quantities of spill containment equipment and materials that might be brought to bear and their predicted effectiveness;

(f) the types and quantities of response and cleanup equipment and materials for mechanical recovery, chemical dispersion and in situ burning methods that might be brought to bear and their predicted effectiveness;

(g) the existing and likely proposed supporting infrastructure and the geographic or community locations of that infrastructure;
(h) the key oceanographic, climatic and ecosystem differences compared to the Gulf of Mexico, including currents, bathymetry, ice cover, weather, seasonal variation, available ambient daylight, etc.;
(i) the expected characteristics of the type of oil and the volume that could be released in each Canadian scenario compared to the oil spilled in the Gulf of Mexico event. Discuss how and why the factors listed below, and other relevant factors would affect the estimates:

- **depth to the oil reservoir,**
- **geologic parameters such as the most likely sedimentary type and facies,**
- **reservoir parameters such as porosity, permeability, pressure and volume,**
- **analysis of local or regional oil from seeps or well tests,**
- **diameter of the drilled hole, casing string and riser pipe, and**
- **physical environmental parameters that would affect the rate of oil flow or degrade its characteristics such as the water depth and temperature, currents, ice cover, prevailing winds and air temperatures;**

(j) the differences of each Canadian scenario compared to the Gulf of Mexico and how these would affect safety and the impacts to environmental and socio-economic valued components;
(k) the arrangements that would be necessary ahead of time to ensure the quickest possible response and how long it would take industry to mobilize and deploy the appropriate resources to respond;
(l) identify the likely sources or countries for the resources described in (k);
(m) how long it would take to regain well control given for the above Arctic scenarios and operating environment, i.e., ice conditions, lack of daylight and possible weather conditions;
(n) the steps to be taken to gain a full understanding of the well control situation;
(o) the volume of oil that could be released and the volume of oil recovered until well control is regained and the likely impact and residual impact on the environment and northern communities;
(p) how long it could take to cleanup a spill of the magnitude of each scenario, taking into consideration the late summer and longer time frame, the likely climatic and oceanographic conditions, response infrastructure, equipment, supplies and trained responders; and
(q) the training needs of, and likely training plan for, company personnel, contractors, community volunteers and other personnel or volunteer responders.

Response to 1.5.1:

Introduction and Background: State of Preparedness Scenario
NEB requested that the Company consider a major oil discharge scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the western Arctic during late summer. As Chevron has recently been awarded EL460 in the Canadian Beaufort Sea within the western Arctic, this is the focus of our response. As we do not have an active lease position in the eastern Arctic, we have not adequately assessed all of the elements identified in this CFI Request to develop a similar scenario for the eastern Arctic. However, should exploration be considered in the eastern Arctic at some point in the future, an eastern Arctic state of preparedness scenario would be broadly similar in the overall approach to oil spill response. Differences in how response strategies are implemented in different locations may be related to the proposed well program, water depth, ice conditions, and logistics, as well as other variables.

In response to the components specified in 1.5.1 and 2.7.1, Chevron developed a scenario based on a subsea blowout occurring at the seabed on October 15. This choice of date was predicated on the fact that this timing is compatible with historical approvals for drilling in the 1980's up to September 25 with two ten-day extensions possible thereafter. The *Chevron Canada Resources AODR Submission Part 1: Briefing Document* provides discussion regarding the historical context for establishing such scenario parameters. In keeping with the objectives to explore industry's capabilities of dealing with a spill when significant ice cover is present, it was decided that a mid-October start to the scenario would lead to a representative mix of conditions progressing from open water through freeze-up and then into a period of substantial new and young ice coverage. The Beaufort Sea scenario is developed in detail for a Beaufort Sea location corresponding to Chevron's recently awarded EL460 in water depths ranging from 800 – 1,700 m (Figure 1).

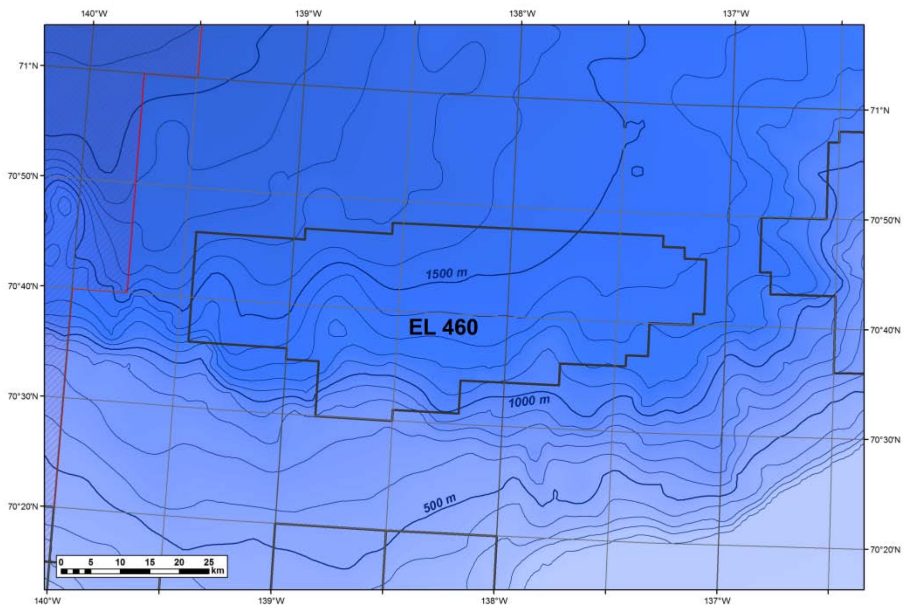


Figure 1: Bathymetry over Block EL 460 in the western Canadian Beaufort Sea.

Oil spill response is demanding under any circumstances, and Arctic conditions impose additional challenges. At the same time, unique aspects of the Arctic environment such as the natural containment provided by the ice itself and the extended daylight during much of the exploration drilling window can work to the responders' advantage. For example, experience with experimental spills and field trials shows that the behavior of oil spills at low temperatures and in ice can enhance spill response and act to mitigate environmental impacts in many situations. On the other hand, some notable Arctic response challenges related to the behavior of oil in ice and offshore 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.

Hundreds of studies, laboratory and basin experiments and field trials have examined all aspects of oil spill preparedness, oil spill behavior and options for spill response in an Arctic marine environment. Our understanding of the characteristics of oil spills in the presence of ice is at a very high level, based on 40 years of active research, principally in the US, Canada and Scandinavia. Chevron continues to play a leading role in the design and execution of large-scale joint industry programs aimed at further improving the state of knowledge in this area, including the development of new Arctic response technologies.

There are limitations to relying on mechanical containment and recovery systems to deal with large spills in the Arctic offshore. Large-scale applications of burning and dispersants are the most effective means of achieving an acceptable level of oil removal from the marine environment in a scenario being considered hypothetically in this discussion. Burning is particularly effective under Arctic conditions where sea ice provides natural containment and increases the window of opportunity for oil to remain relatively fresh and in thick films. The use of dispersants to help mitigate the effects of a spill in open water is well proven in large spills, including the recent Macondo incident. Recent research and field test programs demonstrate that dispersants have the potential to become an effective countermeasure in a number of Arctic situations.

Responses to 1.5.1 (a) and 1.5.1 (b):

Known hazards exist within the Arctic, some of which are unique. Preparation for the unique hazards begins with identification of the likelihood and significance in each drilling location at the time of well design as part of the risk assessment processes.

Permafrost – certain locations of the Arctic have permafrost. Permafrost only occurs above the Risk Threshold Depth. Permafrost location and thickness data are available for the Beaufort Sea region based on existing studies and maps. At the time of well design the management of the permafrost zone would be assessed by design and selection of the drilling fluids, mud coolers, and appropriate casing setting depths. Cement design would consider wellbore integrity through the permafrost and would feature low heat of hydration cements to minimize the impact of the cement curing and the associated heat transfer on the permafrost. A properly designed wellbore will not be compromised by permafrost. Permafrost as a drilling hazard would not contribute to a blowout.

Hydrates – shallow gas hydrates exist in certain locations. Intercepting a hydrate lens can cause a release of gas as the drilling fluids melt the nearby hydrates. Gas evolution from the hydrates adjacent to the wellbore will only continue as long as heat is supplied by the drilling fluids. Management of hydrate gas evolution will be through heat and flow control to the hydrates until a casing string can be cemented across the hazard zone. Hydrates are only present at shallow depths and cold temperatures, above any hydrocarbon bearing zones.

Shallow Gas – Limited pockets of shallow gas can exist above the Risk Threshold Depth in the upper formations in the Beaufort. Geophysical and geological information at the specific well location can identify zones which are likely to contain shallow gas, and the hazard may be avoided by selecting a suitable well surface location. Any shallow gas deposits encountered without a diverter or BOP on the well head will be small and of limited consequence. The gas flow would quickly diminish and normal drilling operations would continue. Once the wellbore reaches the Risk Threshold Depth, casing string design and placement would be in place as a barrier from shallow gas pockets. Presence of shallow gas would not contribute to the risk of a blowout and would not be capable of a sustained release.

Abnormal Pore Pressure – Exploration wells in relatively unexplored basins have greater uncertainty in terms of the pore pressure gradients through the hydrocarbon bearing formations, relative to regions with more offset well data. Using geophysical data and offset wells, the pore pressure gradients can be predicted. Periodic measurement of the porous formations using wireline tools can be used to verify the pore pressure gradient against forecasts. To manage this, mud weights are adjusted accordingly.

Formation Fracture Gradient – Formation fracture gradients are predicted using geophysical and geological data, rock mechanics from basin wide studies and offset wells. Mud weight programs are tailored to anticipated fracture gradients. In the event of excessive mud loss or lost circulation zones, the normal drilling contingency plans are enacted. Casing setting depths are adjusted as required for the pore pressure and fracture gradients encountered on the well.

Ice Features – Ice features that may be encountered during drilling are managed through an established Ice Alert system (refer to *Chevron Canada Resources AODR Briefing Document*). As outlined in the *Chevron AODR Briefing Document*, the Ice Alert procedures incorporate consideration of both Ice and Drilling Hazards. Ice Alert scenarios and disconnect frequency would be considered when designing and selecting the subsea equipment for use in the Arctic. As addressed earlier, redundancy and reliability are key factors in this decision. Between Ice Alert Secure Times and well integrity operational awareness, the emergency disconnects would be minimized and other disconnects would be through planned procedures.

For a hazard involving a severe ice feature to contribute to a blowout, a series of already very low probability events from other geological hazards and compromised well integrity would need to occur simultaneously with exceeding the ice management capacity built into the Ice Alert system. As indicated, future drilling operations would be designed to guard against these types of failures. In the process of developing a future drilling program, project engineers will have acquired necessary data on the ice environment in the vicinity of the proposed drill site, including such ice features as multi-year floes, ridges and hummock fields as well as the much more remote occurrence of ice island fragments.

As drilling proceeds into heavier pack ice conditions, or in the presence of significant ice features, the Secure Time (ST) component of the Ice Alert procedures is increased in duration to allow a reliable, safe disconnect process. The increase in the duration of the Secure time (ST) would take account of current well conditions and the time required for their safe suspension; and the time to safely secure and disconnect the well ahead of the impending ice conditions.

Generally speaking, hazard identification and contingency plans are formulated through Chevron's Operational Excellence Management System (OEMS) processes, including Risk and Uncertainty Management Process (RUMS), well basis of design, Management of Change process (MOC), and through the Safety Plan, Environmental Protection Plan, Emergency Response Plan, Oil Spill Response Plan, and our Ice Management Plan. To have an incident of the magnitude discussed within this scenario, numerous management system elements would have to be bypassed in addition to the failure of mechanical barriers. Hazards are specific to the proposed well location and are identified for mitigation and avoidance through the well design and execution process.

Response to 1.5.1 (c):

The regulatory process that applies to the permitting of any new exploration drilling program in the Canadian Beaufort Sea includes the requirement for a proponent to submit an Environmental Assessment (EA) of the proposed project for review and approval by the applicable regulatory bodies. The EA will identify Valued Components that may be affected by an oil spill and its response activities, including residual hydrocarbons left in the environment after utilizing methods to recover and remove the oil (also refer to section 2.3.1). The Valued Components and the degree of risk will vary with the location, timing and nature of the spill.

The primary means of effectively managing risks to mitigate any impacts include:

1. Reduce the frequency or likelihood of an event to As Low as Reasonably Practical (the ALARP principal) through rigorous management systems, processes, procedures, standards, well design, equipment selection and well control.
2. Reduce the consequences of an event using the same principal, by having systems and resources on site to stop the discharge in the shortest possible time and by having proven response techniques and strategies that can be deployed expediently to maximize recovery and removal of any oil, thereby reducing impacts to valued components and the marine environment, and
3. Monitor long-term impacts and apply the best available restoration practices to ensure that the health of the ecosystem is returned as much as practical to its pre-spill state.

Response to 1.5.1(d):

Chevron utilizes a tiered approach to emergency response consistent with industry best practices. The aspects of the emergency response structure outlined within request 1.5.1(d) are typically provided within the Emergency Response Plans and Oil Spill Response Plans prepared in support of a drilling application.

Chevron Canada's Emergency Response organization is manned by Chevron company employees and contractors based in Canada. This team can be supplemented by Chevron's Worldwide Emergency Response Functional and Regional Teams as well as contractor resources located outside Canada (refer to Section 1.6.2(d)). Response to major incidents may require use of expertise and resources beyond that of the project team operations personnel. The Functional and Regional Teams are comprised of approximately 200 employees who are trained in various aspects of emergency response and are available 24/7 to respond to a major incident. Team members represent a range of skill sets associated with spill and other incident response. They are medically-cleared, trained in the incident command system, and participate in regular exercises to maintain their skills. Three to four Corporate sponsored exercises are held annually at varying locations to test the ability of these teams and line organizations to respond to a major event. Response plans are updated to capture learning from these exercises. Our Worldwide Emergency Response Team includes senior responders trained in the key command and general staff positions and experts in thirteen "functions" including communications, documentation, environment, facilities, finance, human resources, insurance and claims, law, public affairs, purchasing, security, safety, fire and health, and transportation. Chevron also maintains contracts with a wide range of spill response experts and organizations which can provide support in areas including: incident management, wildlife management, oil spill and air dispersion modeling, toxicology, chemistry, fire fighting, communications, shipping and salvage.

Chevron Worldwide Emergency Response Team members are on-call to fill and provide backup for key spill response and cleanup management positions. The team is a select group of about 30 experienced and highly trained individuals from the spill response organizations of the various operating companies. Operating companies may activate one or as many people they feel they need for the response. When activated, team members will report to, and work directly for the operating company handling the incident.

In addition to Chevron's internal response structure summarized above, a number of Federal government departments and agencies (NEB Chief Conservation Officer, Canadian Coast Guard (CCG), Environment Canada, Fisheries and Oceans, Territorial Agencies (Yukon and NWT), Inuvialuit Game Council (IGC), contract personnel, community volunteers and other personnel or volunteers could be involved in many different aspects of the response (wildlife rescue and rehabilitation, community liaison and volunteer training coordination, shoreline clean up assessment, etc.).

The role of the Federal Government in a major Tier 3 incident is currently defined under the Marine Oil Spill Preparedness and Response Regime administered by Transport Canada (http://www.tc.gc.ca/eng/marinesafety/oep-ers-regime-menu-1780.htm). To quote material from this site: "One of the most important programs that fall under the mandate of Environmental Response Systems is Canada's Marine Oil Spill Preparedness and Response Regime. Transport Canada is the lead federal regulatory agency responsible for regime, which was established in 1995 and is built on a partnership between government and industry. Within the framework of the regime, Transport Canada sets the guidelines and regulatory structure for the preparedness and response to marine oil spills. Transport Canada ensures that the appropriate level of preparedness is available to respond to marine oil pollution incidents in Canada of up to 10,000 tonnes within prescribed time standards and operating environments. The Regime is built on the principle of cascading resources, which means that in the event of a spill, the resources of a specific area can be supplemented with those from other regions (geographic areas) or from our international partners, as needed."

Response to 1.5.1 (e):

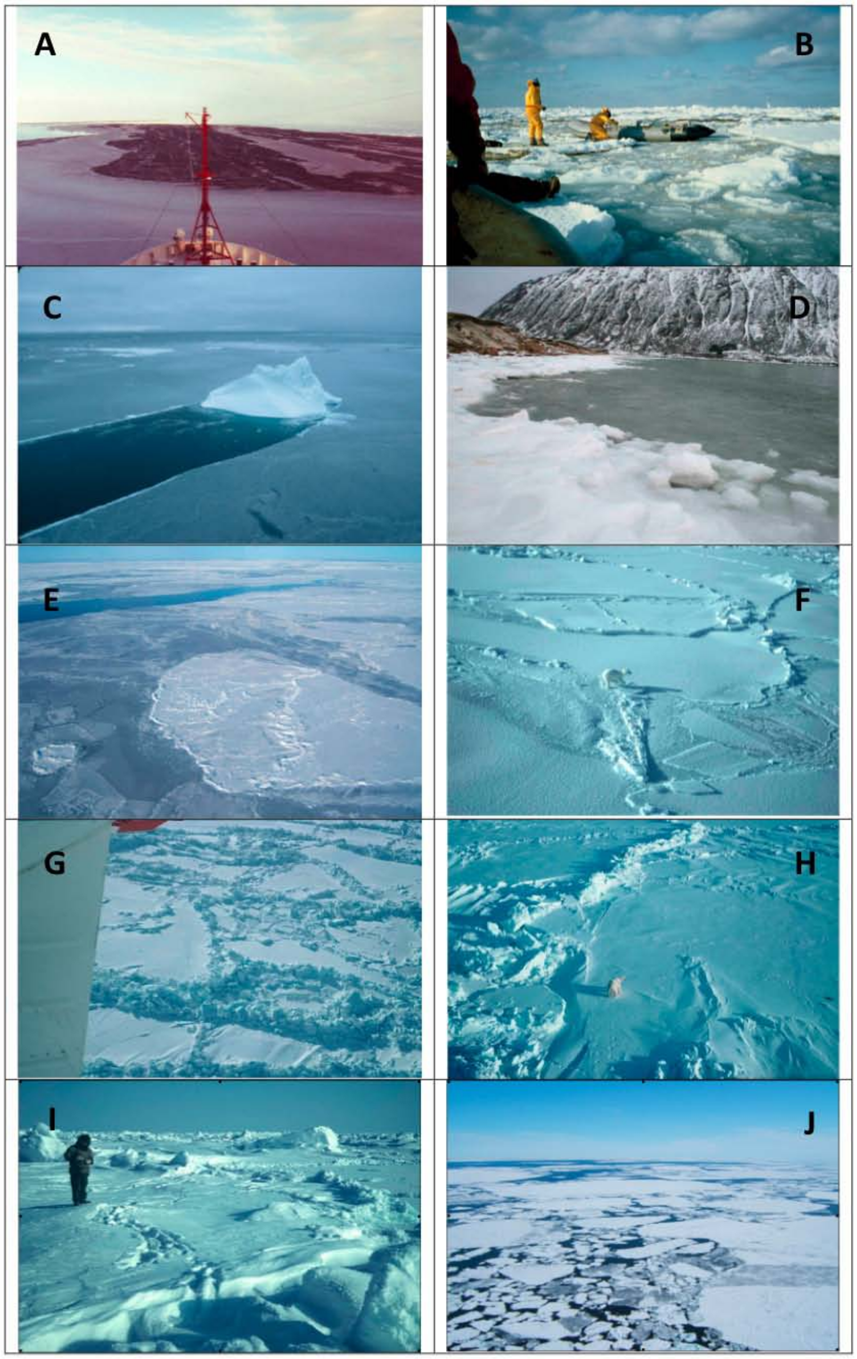
The following discussion covers the key aspects of the spill scenario called for under CFI 1.5.1 (e) and 2.7.1 (a) focusing on the specific requests therein. Each spill response strategy or option is addressed in terms of the state of knowledge surrounding their Arctic applicability in both open water and ice, and particular aspects governing their proposed implementation in support of any future exploration drilling programs in the Canadian Beaufort deep water offshore. This discussion assumes that an Oil Spill Response Plan (OSRP) would always be implemented in parallel with and/or addition to the application of a pre-engineered solution to *stop the flow of hydrocarbons and safely secure the well within the same operating season* (refer to *Chevron Canada Resources AODR Submission Part 1: Briefing Document).* Various credible spill response technologies are discussed for illustrative purposes within the context of this CFI, recognizing that any proposed drilling program would develop and identify a specific OSRP as part of the development application.

Background information is provided here on the fundamental aspects of ice regimes (freeze-up and break-up, ice types, and ice drift) expected in the vicinity of drilling locations within EL 460 during the scenario period October 15-31 when, in the unlikely event of a well control incident, oil could be released prior to completion of a successful capping operation (refer to *Chevron Canada Resources AODR Submission Part 1: Briefing Document).* Knowledge of the expected ice environment and variability in conditions is important to appreciate the potential benefits and drawbacks of using a particular strategy or combination of strategies at any given time and set of circumstances.

Ice Conditions
Some of the most common and important ice forms discussed below are defined by the Canadian Ice Service Ice Glossary (http://www.ec.gc.ca/glaces-ice/default.asp?lang=En&n=501D72C1-1), and are shown in Figure 2, corresponding to the following terms:

A Grease ice at freeze-up
B Slush and pancake ice
C Grey ice with an iceberg wake
D Freeze-up along the coast with an ice foot forming
E Mix of grey, grey-white and thin first-year
F Thin first-year ice with a young bear
G New rubble and ridging in thin first-year ice
H Consolidated thick first-year pack ice
I Surface of a multi-year (old) floe
J Open drift ice 6/10 with small to big floes (20 to 2000 meters)

Figure 2: Ice Forms (Photo credits: D. Dickins; except (D) - E. Owens)



There is considerable seasonal variability of the ice coverage from year to year as demonstrated in Fig. 3 for a location at 70.67N, 138.33W where water depths are ~1400m, representative of Chevron's recently awarded EL460. The figure shows the ice concentration present between July and November for all ice types. In recent years, 2004-2008, the area was ice free by early to mid August. As shown, drift ice may remain longer in some years than in others and there may be ice intrusions from the north. Fall freeze up typically begins by mid-October with ice concentrations increasing quickly over the block in years 2004 and 2005. Fig. 4 shows the appearance of grease ice in October.

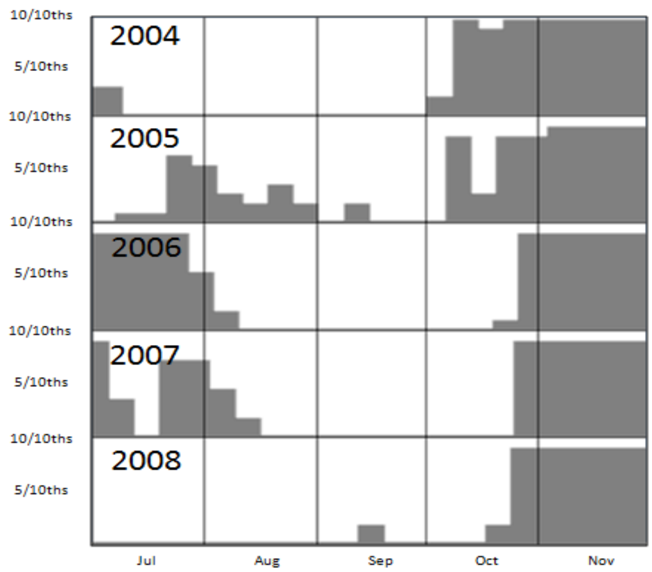


Figure 3: Summer ice concentrations, July to November for recent years. Source: Canadian Ice Service Data

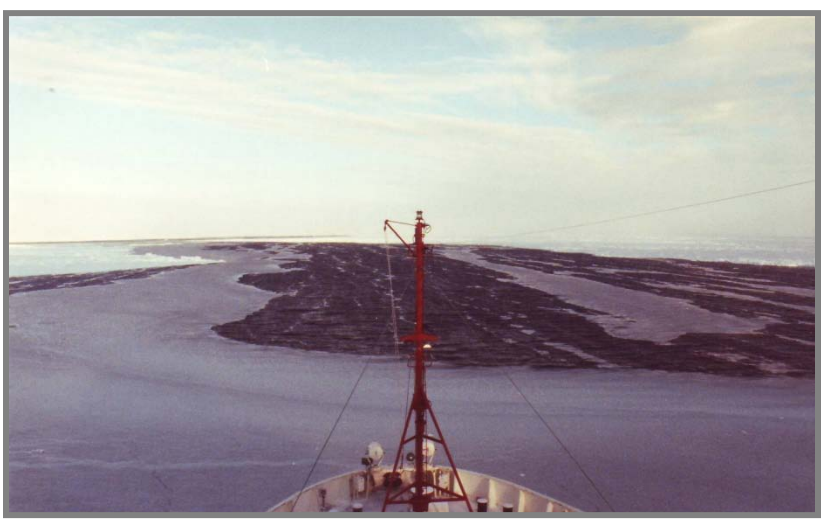


Figure 4: Icebreaker proceeding through grease ice in late October in the Northwest Passage. Photo: D. Dickins

Both first year ice and old ice (comprised of second-year and multi-year) are observed in the Beaufort Sea. First year ice has not undergone a melt season while old ice includes the presence of second and multi-year ice formations that have survived one or more melt seasons. Multi-year ice (two or more years old) will usually be thicker and have a much higher breaking strength when compared to first year ice. It may be heavily ridged creating a hummocked topography. Like ice concentrations, the likelihood of observing old ice varies between seasons. The probability of old ice intrusions tends to increase in the summer season due to relative lack of surrounding ice to confine an individual ice floe's movement.

Using upward-looking sonar data from mooring site #2 (71°N, 133°45W - Department of Fisheries and Oceans Institute of Ocean Sciences (IOS), the ice cover during our scenario period, October 15-31, was classified for 6 years, 1998, 1999, 2000, 2003, 2005, and 2006, based on ice thickness according to the categories shown in the bar graph legend in Fig. 5. The graph shows the average percentage of time each type of ice was present over the 6 years of data. In most years the dominant ice forms in the last half of October are a mix of new and young ice (generally less than 30 cm level thickness). Leads and open areas are still common at this time and can typically make up 10 to 30% of the surface area.

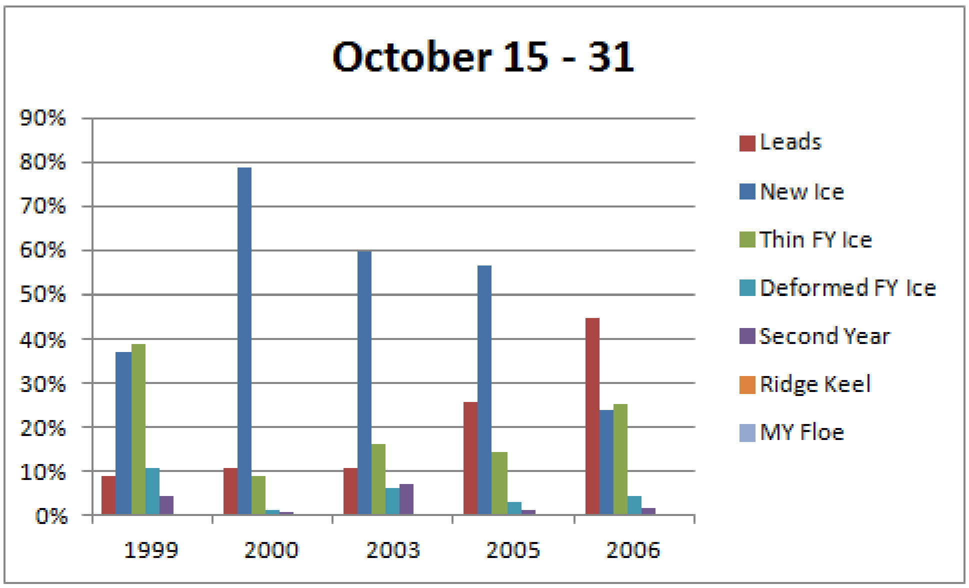


Figure 5: Variability in ice composition during the scenario period.

The same data set used to define the different ice forms likely to be present in the last half of October was also used to derive a probability distribution of ice velocities shown in Fig. 6. The data demonstrates that the ice is relatively mobile soon after freeze-up with median velocities in the order of 30 cm/s. As the pack ice thickens and becomes more consolidated with time, movements gradually decrease and the frequency and duration of periods with close to static conditions increase.

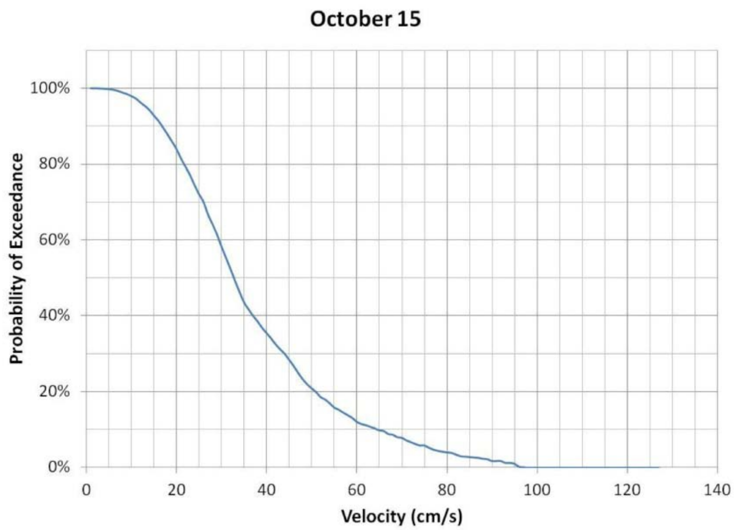


Figure 6: Chart showing the ice velocity probability of exceedence for period of time between October 15th and 31st. This chart includes data from five years: 1999, 2000, 2003, 2005 and 2006. Source: H. Melling, Institute of Ocean Sciences

Overview: Key aspects of a spill response under Arctic conditions
Oil spill response is demanding under any circumstances, and Arctic conditions impose additional challenges. At the same time, unique aspects of the Arctic environment such as the natural containment provided by the ice itself and the extended daylight during much of the exploration drilling window can work to the responders' advantage. Experience with experimental spills and field trials shows that the behavior of oil spills at low temperatures and in ice can enhance spill response and act to mitigate environmental impacts in many situations. (Dickins, 2011). For example:

- Low air and water temperatures coupled with the presence of ice generally lead to much greater oil equilibrium thicknesses, related to reduced spreading rates and smaller contaminated areas. This behavior supports effective burning.
- Evaporation rates are reduced in cold temperatures and ice. As a result the lighter and more volatile components remain for a longer time, thereby enhancing the ease with which the oil can be ignited and dispersed.
- The wind and sea conditions in many Arctic areas are considerably less severe than most open ocean environments, facilitating marine operations. The regional presence of ice dampens wave action and often limits the fetch over which winds might otherwise create larger fully developed waves. This can lead to calmer seas that increase the containment ability of fire resistant booms in open water and very open ice.
- When ice concentrations preclude the effective use of traditional containment booms, the ice itself often serves as a natural barrier to the spread of oil. The natural containment of wind-herded oil against ice edges leads to thicker oil films that enhance the effectiveness of burning.
- With high ice concentrations (7/10 or more) most of the spilled oil (especially from a subsea blowout) would rapidly become immobilized and encapsulated within the ice.
- Oil encapsulated within the ice is isolated from any weathering processes (evaporation, dispersion, emulsification). The fresh condition of the oil when exposed at a later date enhances the chances for effective combustion.

- The fringe of fast ice common off most Arctic shorelines by mid-October acts as an impermeable barrier and prevents oil spilled offshore at freeze-up from entering and contaminating sensitive coastal areas for an extended period of time (up to 9 months in the Beaufort Sea)

On the other hand, some notable Arctic response challenges related to the behavior of oil in ice and offshore operating conditions include:

- Difficulty in accessing oil trapped on or under ice especially offshore in moving pack leads to consideration of an option to track the oiled ice through the winter and access the oil that naturally surfaces through the ice in the spring before break-up.
- Low encounter rates and recovery volumes associated with using independent skimmers to access oil trapped within the ice leads to a reliance on in situ burning to rapidly remove oil contained in isolated, thick pools.
- Significantly reduced effectiveness for conventional containment and recovery systems in any measurable ice concentration (over 10% coverage) leads to reliance on different strategies such as in situ burning with and without herding agents and dispersants (both chemical and oily mineral aggregates (OMA)).
- The combination of extended periods of darkness or twilight for much of the winter and the potential for very low temperatures favor response strategies that either delay direct intervention to the spring when working and flying conditions are more favorable (burning) or rely on immediate intervention at the wellhead to eliminate threats to the environment without risks to worker health and safety (e.g. subsea injection).

In addition to the challenge of dealing with the often dynamic and changing ice environment, the logistics supply chain must also be considered when developing effective response plans for Arctic operations (Ref. discussion below under 1.5.1(g)). The remoteness of any hypothetical Beaufort Sea spill location dictates the selection of environmentally appropriate strategies and technologies that maximize the use of limited infrastructure: for example, techniques such as in-situ burning and dispersants. In contrast to traditional methods of containment and recovery, neither of these options results in massive volumes of oily waste: a significant problem in terms of both temporary offshore storage and safe disposal in the Beaufort region.

The following sections summarize the state of the art and the Arctic applicability of the three response options most often considered when planning a response to any large offshore spill: mechanical, burning and dispersants. Of the three, dispersants are relatively new in terms of an Arctic application, although not in worldwide experience. There is often widespread reluctance to approve large-scale dispersant use, based largely on a lack of understanding of the actual process involved, eventual fate and highly localized toxicity levels. Recent experiences in the Macondo incident shows that, given the alternatives of escalating shoreline impacts and lasting impacts of surface spills seriously affecting marine life, dispersants may be the preferred option to mitigating environmental effects - ultimately removing a high percentage of oil from the water column through enhanced biodegradation. For this reason, the discussion pertaining to dispersants is expanded over the other two response options, in an effort to address a number of key concerns and possible misconceptions related to their use.

A key reference work providing the basis the discussion of response options is SL Ross et al. (2010) – Beaufort Sea Oil Spills State of Knowledge Review and Identification of Key Issues prepared for the Environmental Studies Research Funds (ESRF). These funds are financed from levies on the oil and gas industry and administered by Natural Resources Canada.

Response Options: Containment and Recovery

Containment and recovery (C&R) is generally regarded as the preferred response strategy for responding to marine oil spills in open water, and is mandated as the primary technique in many jurisdictions through regulation (e.g. Alaska). However, there are significant limitations to relying on mechanical containment and recovery systems for large spills at sea in most parts of the world, and these limitations become even more critical in the Arctic. For any large spill in open water, the oil usually spreads rapidly to form a thin layer on the water surface. Substantial lengths of containment boom managed by large numbers of vessels are then required to concentrate these thin oil slicks for recovery. High capacity skimmers used in this application recover significant quantities of water along with the oil. Emulsification can increase the volume of oily liquid recovered by four to ten times, resulting in massive storage and disposal requirements (ESRF 2010). Even with close to unlimited marine resources, such as were deployed on the Macondo spill, the end result in terms of % of spill volume mechanically recovered is often very low (i.e. less than 10%). Regardless of the overall outcome, any reliance on mechanical recovery becomes even more problematic when even small amounts of drift ice (as little as 10% coverage) interferes with the flow of oil to the skimmers and results in even lower recovery rates.

As a result of these constraints, response to a large marine spill in an Arctic region is unlikely to rely primarily upon containment and recovery. Depending on conditions at the time, mechanical systems such as over-the-side brush/bucket skimmers may continue to be used to deal with smaller spills such as isolated pockets of oil trapped between ice floes and in leads (Fig. 7).

Figure 7: Over the side recovery with a Lamor brush/bucket from the icebreaker *Hilje* during an accidental spill in the Gulf of Finland, April 2003. Photo: *Helsingen Sanomat* - Juhani Niiranen

Response Options: In situ Burning (ISB)

The use of in-situ burning (ISB) as a spill response technique is not new, having been researched and employed in one form or another at a variety of oil spills since the late 1960s including limited use during the *Exxon Valdez* and extensive use during the recent Macondo incident. In-situ burning is especially suited for use in ice conditions, and much of the early research and development on in-situ burning focused on its use for spills on and under solid sea ice, demonstrated effectively through large-scale experimental spills in the Beaufort Sea in 1975 and 1980. More recently, the research has addressed burning spills in pack ice of various concentrations and especially in slush and brash ice. In general, the technique has proved to be very effective for thick oil spills in high ice concentrations and has been used successfully to remove oil resulting from pipeline, storage tank and ship accidents in ice-covered waters in Alaska, Canada and Scandinavia (SL Ross et al., 2010).

In the early 1990's, at the time of the last environmental review of an exploration drilling program in the pack ice zone, the *Kulluk* Drilling Permit Application, it was assumed that there was no safe, practical way to conduct sustained clean-up operations through the winter months in a dynamic ice area. At that time, the primary approach put forward to remove the residual oil left after dispersion (natural and induced) and evaporation and mechanical clean up was through a large-scale aerial ignition program in the spring following the blowout. This approach is still valid today and forms one of the primary options for dealing with a subsea blowout in the present scenario. Our current state of knowledge regarding burning oil under Arctic conditions is summarized below from SL Ross et al. (2010).

Figure 8: Burning oil among ice collected in a fire resistant boom during the 2009 SINTEF Oil in Ice Joint Industry Project (Chevron was a participant) in the Norwegian Barents Sea. The percentage of the oil removed through in situ burning ranged from 89 to 98%. Photo: Potter (SL Ross) in Sorstrom et al. 2010

Basic Burn Research

In the 1990s, research on ISB processes focused on the burning of water-in-oil emulsions. The basic conclusions of this research carried out in Alaska, Canada and Norway were that:

- For most crude oils, emulsified water contents in excess of 25% preclude ignition (some very light crudes that do not form stable emulsions can be ignited with water contents up to 60%).
- The burn rate and efficiency for emulsions decline with increasing water content.
- Wave action makes ignition of emulsified slicks more challenging, slows in-situ burning rates, and increases the thickness of residue that remains when the slick extinguishes naturally.
- The presence of ice pieces in the slick does not significantly reduce emulsion burning rates or efficiencies.
- The maximum wind speed for successful ignition is 10 m/s.

In the early 2000s, a research program was carried out to determine the effects of slush and frazil ice (fine spicules or plates of ice suspended in the water) on the 'Rules of Thumb' for in-situ burning (Buist et al., 2003a). The following rules were proposed based on the experiments:

- The minimum ignitable thickness for fresh crude oil on brash or frazil ice is 1 to 2 mm, or approximately twice that on water.
- The burn rate of thin (3 to 5mm) slicks on frazil ice is approximately half the rate for the same size of slick on water, and the burn rate of these slicks on brash ice is approximately ¼ the rate on water.
- The residue remaining for thin (3 to 5 mm) slicks burned on water is 1 mm; on quiescent frazil or brash ice it is approximately 1.5 mm; and on frazil or brash ice in waves it is approximately 2 mm.

<u>Potential Environmental Effects Related to In Situ Burning</u>
In the 1990s there was a concerted research effort to determine the potential environmental impacts (primarily from the smoke plume and burn residue) of in-situ burning. Work by Canadian and US teams greatly advanced the understanding of what was contained in the smoke from an in-situ oil fire on water and how to predict its downwind impacts on the environment (Fingas et al. 1995, Ross et al., 1996, McGrattan et al. 1995).

The burn residue (the unburned oil remaining on the water surface when the fire extinguishes naturally) was also studied in the 1990s. A component of the ESTS research was to determine the aquatic toxicity of the burn residue (Daykin et al. 1994 and Blenkinsopp et al. 1997) while an industry-funded research program examined the likelihood of burn residue sinking as it cooled after the fire went out (Buist et al. 1995, SL Ross 1998). Bioassays showed very little or no acute toxicity to marine life in salt water for either the weathered oil or the burn residue. These findings of little or no impact were validated with further studies by Gulec and Holdway (1999).

Chevron's scenario is based on an Amauligak-like crude with an API of 27.4° (refer to Section 1.5.1(i)). Residues from an efficient burn of this oil or equivalent with a starting thickness of 10-mm (characteristic of wind-herded oil on ice melt pools in the spring) will not be dense enough to sink, even in fresh water (Buist et al. 1995).

A final component of the research on in-situ burning impacts was to determine the overall mass balance of polynuclear aromatic hydrocarbons (PAHs) consumed and created by in-situ burning Important findings were that PAHs in oil are largely consumed by combustion. During the Newfoundland Oil Burning Experiment (NOBE; August 1993), PAH concentrations were much less in the plume and in particulate precipitation at ground level than they were in the starting oil (Fingas et al. 2001).

Technology developments to enhance burning in spill response
One of the first technological developments to occur since large-scale ISB was considered in previous Beaufort scenarios was a new formulation for Helitorch fuel to improve the ignition of emulsified and hard-to-light slicks (Guenette and Sveum 1995). Following the successful test burn at the *Exxon Valdez* spill (Allen, 1990) considerable effort went into refining fire boom technology and developing new fire-resistant and fireproof boom designs (including the use of water cooling) for improved durability and handling (e.g., Allen 1999). As a direct result of these fire boom development efforts, two fire boom test protocols were developed, and eventually adopted by the American Society for Testing and Materials (ASTM F2152 - Standard Guide for In-situ Burning of Spilled Oil: Fire-Resistant Boom – ASTM 1999).

In-situ burning is an oil spill response option particularly suited to remote ice-covered waters. The key to effective in-situ burning is thick oil slicks. Concentrated pack ice can enable in-situ burning by keeping slicks thick (Buist and

Dickins 1987). However, in very open drift ice conditions, oil spills can rapidly spread to become too thin to ignite. Fire booms can collect and keep slicks thick in open water; however, even light ice conditions make using booms challenging if not impossible (Bronson et al. 2002). Potter and Buist (2010) report the highly effective burning of oil within small ice pieces and brash collected within a fire-resistant boom during the 2009 field experiments in the Norwegian Barents Sea (Figure 8).

A multi-year joint industry project was initiated in 2004 to study oil-herding chemicals as an alternative to booms for thickening slicks in drift ice conditions for in-situ burning. Small-scale laboratory experiments were followed by mid-scale testing in large basins (e.g. Buist et al. 2007). The cold-water herder formulation used in these experiments proved effective in significantly contracting oil slicks in brash and slush ice concentrations of up to 70% ice coverage. Herded slicks in excess of 3-mm thickness, the minimum required for ignition of weathered crude oil on water, were routinely achieved. Herded slicks were ignited and burned at air temperatures as low as minus 17°C. The burn efficiencies measured for the herded slicks were only slightly less than the theoretical maximums achievable for equivalent-sized, mechanically contained slicks on open water. The concept of using herding agents to burn free-drifting slicks in pack ice was successfully field tested for the first time in 2008 as part of a the Joint Industry Program on Oil Spill Contingency for Arctic and Ice-Covered Waters organized by SINTEF in Norway (Buist et al., 2010). Burn removal effectiveness in that test was estimated to be in the order of 90%. The residue floated readily and was recovered manually from the water surface and ice edges.

Decision-making Guidelines

The short-lived smoke plume emitted by a burning oil slick on water has always been the main ISB concern to the public and regulators. Low concentrations of smoke particles at ground or sea level can persist for a few miles downwind of an ISB. The smoke is unsightly, but smoke particulates and gases, are quickly diluted to far below levels of concern as referenced above.

Numerous agencies, primarily in the US, have established guidelines for the safe implementation of burning as a countermeasure. US National Institute of Standards and Technology (NIST), NOAA and Environment Canada have computer models that can be used to predict safe distances for downwind smoke concentrations. In 1994, the Alaska Regional Response Team (ARRT) incorporated In-situ Burning Guidelines for Alaska into its Unified Response Plan. They were the first Arctic area to formally consider ISB as a response to oil spills and their guidelines are considered the most fully developed to date (AART 2008). American Society of Testing and Materials (ASTM) began developing standards associated with in-situ burning in the late 1990 (ASTM 2009). The U.S. Coast Guard produced an operations manual for in-situ burning (Buist et al. 2003c) that details all the considerations and steps to be taken for open water in-situ burning with fire booms (Buist et al. 2003b).

<u>Application of ISB in Chevron's NEB AODR Beaufort Scenario</u>

The operational application of burning is fully mature with a number of recognized guidelines and procedures to ensure the safety of personnel on site and any nearby crews.

As requested by the NEB, Chevron's response to a "Macondo equivalent" scenario in late summer would utilize in situ burning in a variety of ways to deal with surfacing oil in a mix of open water and ice:

1. Large-scale burning in open water and in very open ice cover with the latest generation of fire-resistant booms as successfully deployed during the Macondo incident prior to freeze-up.

2. Burning by using herding agents to thicken free floating oil in open drift ice where booms are not practical and there is insufficient natural containment provided by the ice to create opportunities for naturally wind-herded pools.
3. Burns of opportunity, igniting any thick wind-herded oil pools that may appear in openings within high concentrations of pack ice throughout the winter. This would be accomplished by tracking the oiled ice movements with closely spaced GPS buoys and monitoring surface conditions on a regular basis from ships and helicopters.
4. A renewed and much larger-scale focus on targeted burning of wind-herded oil on surface ice melt-pools during the following spring and early summer (April to June).

In open water, the oil would rapidly spread to a film thickness too thin to support ignition, maintain combustion and achieve a significant removal efficiency (2-3 millimetres required as a minimum). In this case, a number of fire-resistant boom systems would be maintained a safe distance from the discharge point into the prevailing oil drift. Each system would comprise boom towed by a single vessel separated from one boom end by a towline. The other end of the boom would be held in position by a paravane, a system developed in Sweden that is now accepted as proven means of towing boom with half the number of vessels. A typical operational cycle could see collecting and thickening oil within the fire booms over an ~3 hour period, towing off to one side outside the slick, igniting and burning for an hour, and reentering the oil for another cycle of collection. Given the 11-12 hours of daylight available during late October, an estimated 3 collection and burn cycles could be completed for each vessel/boom system in a working day, weather and ice permitting.

This type of operation could continue as long as the ice coverage is less than ~10%. In intermediate ice concentrations (1-5/10) herding agents (basically non-toxic surfactants) can be applied at very small dose rates to create much thicker oil slicks that can be effectively ignited and burned at high efficiencies (over 80% for individual burns), without the need for fireproof booms (see previous discussion of state of knowledge in this area).

In higher ice concentrations (over 50% coverage), a portion of the surfacing oil will still rise to lie in leads and openings within the new ice cover. Even with initially thin films, this oil will be rapidly herded by wind to collect against ice edges in thicknesses capable of supporting efficient combustion. These isolated pools can be ignited with a helitorch or hand-held igniters deposited from a small boat. Both of these procedures have been used previously in large-scale experiments in the Beaufort Sea, Norway and off the Canadian East Coast (see Fig. 9).

Figure 9: Aerial view of burning oil in a mix of pack ice and slush off Cape Breton Island in 1986. Photo: R. Belore in SL Ross and DF Dickins (1986)

Eventually, as the new ice cover expands in coverage and begins to consolidate, in the absence of any intervention at the discharge point (see discussion re: dispersants as follows) most of the oil will surface under the ice as thin films. This oil will remain trapped under the new or young ice and become quickly encapsulated as a distinct layer by new ice growth. A small volume (in the order of 5%) could remain exposed in leads and openings often present in the drifting pack during winter. By monitoring the track of the oiled ice through the winter and conducting frequent surveillance (helicopter, fixed wing and/or drones) it will be possible to identify possible targets for burning as the opportunity presents itself (Fig. 9).

The encapsulated oil is isolated from the normal weathering processes. Because the majority of the hypothetical oil would be trapped under thin ice in October, it will naturally migrate to the surface or be exposed through surface melt very early in the ice deterioration process. Solar heating of the oil layer near the ice surface could cause the oil to become exposed on surface melt pools as early as late April. Continued oil exposure will occur in May and almost all of the oil would be available on the surface in early June. At this stage, wind acting on the surface of the melt pools effectively thickens the oil films against the edges of the melt pools. The resulting scattered pools of oil typically up to 10 mm thick, can then be ignited from the air with helicopters and produce highly effective removal rates in excess of 90% for individual burns. A portion of the oil will remain unignitable through a combination of too thin films, or too small melt pools to provide a realistic target for an igniter. The principal of burning oil in this manner was proven in large-scale experiments carried out in the Beaufort Sea in the mid 1970’s (Norcor, 1975) and again in the during the Dome Petroleum simulated blowout under ice (Dickins and Buist, 1981) (Fig. 10).

Figure 10: Burning oil on melt pools with igniters dropped from a helicopter during a simulated blowout under ice in McKinley Bay NWT. Source: Dickins and Buist (1981)

In summary, burning is particularly effective under Arctic conditions where sea ice provides natural containment and increases the window of opportunity for oil to remain relatively fresh and in thick films. There is no other response strategy that has the potential for such high effectiveness (over 90% in individual burns) while necessitating minimal resources. Some key points associated with the use of in situ burning include:

- Recent technology developments include better fire-resistant boom and the use of herding agents in conjunction with burning.
- The helitorch system of delivering ignition to the oil pools remains the best aerial option in terms of proven performance and certification by both Transport Canada and the FAA.
- With an extensive database and decades of experience successfully burning oil in different ice environments as well as offshore in a large-scale blowout situation (Macondo 2010), in-situ burning should be considered as a proven, primary technique rather than as often labeled, an "alternative" strategy (this point applies equally as well to the issue of dispersants – see discussion following).
- Proven decision-making tools exist to aid an incident commander in determining the safety and likely efficacy of approving a burn operation.

Response Options: Dispersant Use

The use of dispersants to help mitigate the effects of a spill in open water is an accepted practice in many parts of the world, for example Europe, including the UK and France. Recent research and field test programs over the past ten years have focused on investigating the applicability of dispersants to an Arctic spill in an area of dynamic pack ice cover, conditions once thought to be out of bounds for dispersant consideration due to a lack of naturally induced mixing energy. The results to date have been largely positive and demonstrate that dispersants have the potential to be a very effective countermeasure in a number of Arctic situations. However, aerial and surface applications have drawbacks in being able to treat a significant portion of the spill at the optimal dispersant to oil (DOR) ratios needed to initiate effective and sustained dispersion.

Experiences with the recent Macondo spill have now demonstrated the potential for large-scale subsea dispersant injection as a promising new approach to deep-water blowout spill mitigation that could far exceed the effectiveness that can be achieved by aerial application. A dedicated rapid response system for subsea injection using available pre-deployed equipment and resources could operate without being directly affected by ice conditions at the surface or other response constraints such as imposed by temperature and weather extremes and lack of daylight.

A further development based on Oily Mineral Aggregates (OMA), (developed through research at the Centre for Offshore Oil, Gas and Energy Research, Fisheries and Oceans Canada, Dartmouth together with the Canadian Coast Guard Quebec region) could overcome many of the objections related to the use of chemical dispersants while at the same time utilizing natural substances such as Bentonite clay materials, stockpiled on site as an integral part of an exploration program. Chevron continues to investigate this technology as a potential key component of a program in the Beaufort Sea.

The Use of Dispersants in the Arctic

In the absence of any reliable means of recovering a major portion of a large spill mechanically, dispersants provide a potential option to significantly reduce the amount of oil that will either surface into open water prior to freeze-up or surface beneath the ice after freeze-up. As discussed above, ISB in the spring is a potential strategy for dealing with a portion of the oil trapped within the ice. However, dispersants offer an ability to prevent most of the oil from surfacing at the source and to provide for rapid biodegradation of a large percentage of the spill. These potential attributes provide strong reasons to seriously examine and consider the large-scale application of dispersants throughout a deepwater Beaufort Sea blowout.

Objections to the use of dispersants under Arctic conditions are typically based on concerns about their effectiveness related to the lack of wave energy in the presence of ice and cold water. Recent research results and field tests demonstrate that there are no technical or scientific obstacles to the use of dispersants in the Beaufort Sea. The following points modified from SL Ross et al., 2010 review what can be said in response to these concerns from our current state of knowledge.

Dispersant Effectiveness (DE) in Cold Water

There is a general misconception that cold temperatures inhibit dispersant effectiveness. Colder temperatures do increase the viscosity of the spilled oil and dispersant product, but as long as the oil viscosity does not exceed 20,000 to 40,000 cP and the pour point of the oil is lower than the ambient water temperature (as is the case with crudes generally found in Beaufort Sea discoveries to date) dispersants have been shown to be effective. Conventional dispersants have been formulated to be relatively non-viscous in cold temperatures and can be successfully applied in cold weather as in the 2009 Norwegian oil in ice field experiment (Daling et al. 2010).

Presence of Ice

Ice may affect a surface-based dispersant operation primarily through its influence on the mixing energy available to generate and then diffuse small oil droplets once the dispersant has been applied. The presence of broken ice in concentrations above 30 to 50% significantly dampens the wave field and changes the surface mixing conditions. Research over the past six years has shown that ice generates sufficient localized energy through its mechanical grinding and pumping actions as it rises and falls and interacts even in a dampened wave field to disperse chemically treated oil (Owens and Belore 2004). The surface application of dispersants to oil present at ice edges in leads or between ice floes is now considered to be a viable countermeasures option under some circumstances, depending on the ice conditions and prevailing environmental conditions.

In a complete ice cover (>95% coverage) situation there is clearly insufficient natural mixing energy to generate oil dispersion once dispersant is applied; in that case, most of the oil from a subsea release will be trapped under the ice and consequently become inaccessible to a surface spraying operation from vessels or aircraft. Tank tests in

Finland demonstrated that an icebreaker propeller could provide sufficient energy to create lasting dispersion of any exposed oil, even in close pack ice (Nedwed et al., 2007). Tests in 2009 in Norway demonstrated that the mechanical energy provided by a ship's propeller could be used to both expose trapped oil for dispersant application and to shear the treated oil into a fine oil cloud that will diffuse throughout the water column and potentially remain in suspension (Daling et al., 2010). Other researchers have found similar results, using the turbulence from a ship's propeller or from fire monitors, for example in an experimental spill in the Gulf of St. Lawrence carried out by Fisheries and Oceans Canada and the Canadian Coast Guard and using OMA, a natural clay-based dispersant (Lee et al., 2009).

Additional research is needed to fully assess the range of conditions and oil types where surface application of dispersants to oil in ice might be viable. Regardless of its technical potential, this specific aspect of dispersant use is viewed as a supplemental tool much like using over-the-side mechanical systems to recover isolated oil pools trapped among ice. These surface-based approaches are limited by the ability to access only a small percentage of the spill as discussed below. The greatest potential benefits from using dispersants with a large release volumes represented by a Macondo-like incident rely on introducing the dispersant where it can be most effective at the lowest possible dispersant to oil ratios (DORs).

Application Systems

The remote location of the Beaufort Sea dictates that careful pre-planning and preparations be made in order to launch either a large-scale surface-based dispersant operation or a sustained injection of dispersant and/or OMA subsea. If proposed by the Operator and approved by the NEB, an appropriate dispersant stockpile, dispersant spraying or injection systems, and suitable vessels or aircraft will need to be identified and secured as part of the drilling program. On a positive note, the largest stockpile of dispersants in North America is located in Anchorage, Alaska, a relatively short distance from the Canadian Beaufort Sea. Subsea injection would make use of dispersants and/or OMA in place onboard a dedicated support vessel (not on the rig) and specially engineered delivery systems designed as an integral part of the well design. With all the necessary resources on site, subsea injection could then commence once conditions are appropriate.

Surface application of dispersants uses a variety of platforms including boats, helicopters, and fixed-wing aircraft. In order to deal with the large potential slick area resulting from a Macondo-scale incident, surface dispersant delivery would need to rely heavily on airborne delivery. While providing rapid coverage over broad ocean areas large aircraft are less adept at hitting discrete slicks and patches or windrows as might be found in a partial ice-covered environment. Part of the dispersant applied in a high-volume airborne delivery system such as the Lockheed C-130 Hercules Airborne Dispersant Delivery System (ADDS) pack is often wasted because of the extreme difficulty in achieving an optimal dispersant to oil ratio (DOR) when the slick is comprised of thin and thick portions. This problem with fixed-wing aircraft becomes more acute in dealing with discrete slicks and patches in a mix of ice and open water. At some point, as the coverage of new ice after freeze-up rapidly increases (Fig. 11), the continued aerial application of dispersants can no longer be justified and further dispersant use at the surface will need to rely on vessel spray systems (see following).

Figure 11: Aerial dispersant application systems. Photos: A. Allen

A recent innovation in this area developed in Norway and tested in the SINTEF JIP experiments in 2009, addresses the problem of targeting delivery for isolated oil pockets trapped among pack ice in leads and between floes. The device is an articulated spray arm, similar to those used for aircraft de-icing operations. The arm provides up to tens of metres reach from the side of the application ship, and the series of nozzles on the arm provide more accurate delivery of the dispersant to the target areas. The prototype device was tested in laboratory experiments, and then used successfully in the 2009 tests in dense pack ice in the Barents Sea (Daling et al., 2010). Any of these spot application processes, relying on the artificial introduction of mixing energy will of necessity be most applicable to small areas where the oil is visible in leads and openings. Soon after freeze-up, the majority of the oil released will be trapped under the rapidly forming new ice and be unavailable for dispersion from the surface.

As a means of overcoming the known limitations of surface dispersant application systems, Chevron proposes to consider the use of subsea injection, the only countermeasure that can operate independent of surface constraints such as darkness, strong winds, and cold temperatures. Subsea injection of dispersant at the point where the wellbore fluids exited the well (riser) was applied for the first time on a large scale in the Macondo spill. Evidence from a variety of expert observers, before and after aerial observations and underwater sonar profiles of the oil plume, point to a potentially high degree of effectiveness, with a significant percentage of the oil volume being converted to drop sizes below 100 microns, the threshold where the oil essentially remains suspended for a long enough period to become biodegraded before it can rise to the surface. In the Macondo incident, subsea injection systems and procedures were developed on an ad hoc basis in response to the actual situation day by day. In any future Beaufort application, fully engineered and tested delivery systems would be considered.

The issue of estimating dispersant effectiveness during the Macondo incident (both subsea and surface) was controversial, even among the experts and peer reviewers (NOAA Oil Budget calculator). In the end, the compromise used was to estimate that for every volume of dispersant injected subsea, an average of 40 volumes of oil were permanently dispersed into the water column at depth. The range of uncertainty assigned to this expert "guess" was from 20 to 90 gallons of oil permanently dispersed for each gallon of dispersant injected. Tests conducted at a number of laboratories during the Macondo incident demonstrated clearly that with the highly efficient mixing of dispersant and oil possible through subsea injection, close to complete dispersion is likely to occur at much lower DORs than considered feasible in aerial or ship-based applications – in the range of 1:100 or greater rather than the traditional 1:20 “rule of thumb”.

At this stage, there are a multitude of opinions and theories regarding the efficacy and environmental acceptability of applying dispersants at the unprecedented scale experienced in the response to Macondo (18,000 bbl subsea and 25,000 bbl at the surface). However it appears clear that without this level of dispersant application together with multiple *in-situ* burns, the impacts to the surrounding coastline and associated marine and bird life could have been much more severe - according to a recognized world expert in shoreline assessment and clean-up following large spills (Owens, pers. Comm.).

If utilized in any future Beaufort Sea drilling operation, any dispersant injection systems would be designed, tested, proven, and approved by regulators before being installed as an integral part of the well design. Dispersant would be introduced directly into the well bore or flowing well stream. The necessary stockpile of approved dispersants (chemical and/or OMA) could be available on site or elsewhere suitable and consistent with timely application, such as stored on a support vessel independent from the exploration rig.

Degradation of Dispersed Oil in Arctic Environments

Microbial degradation of petroleum hydrocarbons can be one of the most important processes for removing spilled crude oil from marine environments. Degradation of crude oil by natural assemblages of microorganisms in marine waters has been demonstrated repeatedly both during spills and in experiments. Oil degrading microorganisms (ODM) are widely distributed through the worlds’ oceans from the tropics to the arctic. Of particular interest here is that ODM have been found in marine waters in numerous arctic locations.

NewFields and University of Alaska Fairbanks Institute of Northern Engineering (INE) are conducting research on the biodegradation and biological effects of physically and chemically dispersed petroleum on Arctic species under Arctic conditions at the BARC facility in Barrow, Alaska. Interim findings publicly presented in a memorandum (Newfields, 2010) are reported for these two research areas and include:

<u>Toxicology</u>

- Preliminary data analysis suggests that Arctic species demonstrate similar or slightly less sensitivity to petroleum than has been reported in tests with temperate species.
- Additional testing of the dispersant Corexit 9500 on the Arctic copepod, compared to previous tests with a temperate copepod (*Eurytoma affinis*) indicates that the Arctic copepod is less sensitive in dispersant-only tests and that the toxicity of the dispersant occurs at concentrations that are much higher than the recommended use concentrations.

<u>Biodegradation</u>

- Biodegradation of physically and chemically dispersed petroleum was examined using Arctic waters at -1.0 °C and at +2.0 °C and their indigenous microbes. Two experimental respirometry runs under cold Arctic conditions demonstrate that Arctic microbes are capable of degrading hydrocarbons (<60% removal of total petroleum, saturate and polynuclear aromatic hydrocarbons over the experimental period of 56 days). This is a critically important finding in view of opinions still held in many quarters to the effect that degradation of hydrocarbons will not occur in cold Arctic water at a significant rate.

Net Environmental Benefit Analysis and Planning

Dispersants provide potential environmental protection from spilled oil by dispersing oil slicks into the water column, where they can be more quickly diluted and degraded. As such, dispersants can reduce immediate and long-term risks posed by spills to species on the sea surface, while possibly increasing short-term risks to organisms in the upper water column at certain times of the year. Decisions about dispersant use involve making choices between risks posed by the untreated spills and those posed by the dispersed spill, that is, deciding whether dispersants offer a net environmental benefit. Dispersing oil spills has been shown to offer clear net environmental benefits in many operational areas of North America. (SL Ross et al., 2010).

In Canada, guidance for dispersant use is contained in Environment Canada (1984), "Guidelines on the Use and Acceptability of Oil Spill Dispersants." That document stipulates that dispersants must be used in situations where "adverse impacts associated with chemical dispersion are less than those without chemical dispersion." The guidelines provide no guidance as to how 'adverse impacts' are to be estimated. However, they do specify information to be provided to Environment Canada concerning dispersant products that might be used in spill response operations in Canadian waters. Environment Canada has considered revising its operating procedures, but has yet to formally publish these changes or submit them for review by the Canadian environmental and spill response community.

A number of region-specific dispersant net environmental benefit studies have been completed in recent years in areas such as the Newfoundland Grand Banks (S.L. Ross 2007) and Southern California (Trudel et al. 2003).

In order to facilitate quick decision-making during a spill, regulatory agencies in many parts of the world have established systems for expediting decisions regarding dispersant use. This may include establishing dispersant pre-approval zones or conditions, or developing tools to assist in the decision process. One such system was developed for the Southern Beaufort Sea area in the 1980s (Trudel 1988). There is no reason to believe that some form of pre-approval process could not succeed today with all parties involved in the Regional Environmental Emergency Team (REET) – Inuvialuit Game Council (IGC), Territorial Governments, Environment Canada, CCG and so on.

Use of Oil-Mineral Aggregates (OMA)

In recent years, the Department of Fisheries and Oceans together with the Canadian Coast Guard has been researching the concept of adding mineral fines to oil spills in ice in the St. Lawrence River Estuary, then subjecting the treated slick to the prop wash from icebreakers in order to promote dispersion of the spills and enhance their biodegradation (Lee et. al, 2011 (draft in progress), Lee et al. 2009).

Many research studies have shown that physically dispersed oil droplets aggregate readily with suspended particulate matter (SPM), such as clay minerals or organic matter, to form oil-SPM aggregates (OSA), also called OMA. When OMA forms, the dense mineral fines (2.5 to 3.5 times denser than most oils) adhering to the oil droplets will reduce the overall buoyancy, retarding their rise to the surface, promoting their dispersion throughout the water column at low concentrations, and ultimately enhancing their biodegradation by natural bacteria. Preventing the surfacing of the droplets under the ice over a subsea blowout could provide a significant environmental benefit.

Studies for the Canadian Coast Guard conducted in a large basin in 2006 demonstrated that OMAs formed instantly in both slush ice and broken ice. A mixing time varying between 20 and 30 minutes was sufficient to disperse about 50% of the spilled oil. In January 2008, with help from the Canadian Coast Guard icebreaker *Martha Black*, the theory of using an icebreaker's propeller to create OMA was tested in real ice conditions (Lee et al. 2009). Several experimental spills of about 200 litres of fuel oil were carried out in the St. Lawrence River near Matane, Québec. Chalk fines were mixed with seawater and sprayed onto the spilled oil, while the propeller of the icebreaker was used to mix the slurry with the oil and disperse the mixture. Visual observations confirmed that the oil was physically dispersed into the water column and that it did not resurface, as was the case in the tests without treatment by addition of mineral particles. Additional laboratory, tank testing, and fieldwork will be required to further develop this potentially promising countermeasure both as surface applications with a partial ice cover and possibly in the form of subsea injection.

Responses to 1.5.1 (f) and 2.7.1 (b):

The components identified within Request 1.5.1(f) and 2.7.1(b) would be addressed within the Emergency Response Plans and Oil Spill Contingency Plans prepared in support of a drilling application. Chevron's approach to oil spill contingency is based on having initial key resources (booms, ignition systems, dispersant) at or near site and capable of being quickly mobilized thus reducing the impact of equipment or personnel mobilization to the region (See related discussions under CFI 1.5.1 (g) and (j)). Response times to initiate the principal countermeasure strategies will be rapid once the two immediate priorities are dealt with following an incident: eliminating any further risks to human health and safety, and making every effort to secure the integrity and continued survival of the drilling rig.

Response to 1.5.1 (g):

The general lack of infrastructure in most Arctic regions and more distant offshore locations of potential future drilling targets dictates the need for an increased in-field self-sufficiency of operating systems to provide the most effective response to any accidental spill. Depending on the severity of the incident, a global response effort should always be considered, utilizing any resource available that can aid the overall long-term response effort. A combination of a highly effective marine support fleet with the effective use any applicable regional infrastructure will form the basis of a robust oil spill response plan (OSRP).

The choice of response techniques is strongly influenced by the ability to support a given strategy in terms of logistics (refer to earlier discussion under the Overview response to 1.1.1(e) and 2.7.1 (a)).. These challenges when applied to the Beaufort region mean that techniques requiring less marine support and generating less waste are favored over conventional containment and recovery. The following brief discussion summarizes the known logistical infrastructure existing today in the Beaufort Sea/Mackenzie Delta area.

General Overview

The major logistical centers in the Beaufort Sea / Mackenzie Delta region are linked to two of its major settlements, Inuvik and Tuktoyaktuk, that both have summer marine access, shore facilities, seasonal road access and established airports.

The Dempster Highway connects the North Klondike Highway in the area of Dawson Creek with Inuvik (this road is out of service for two periods during freeze-up and break-up). A seasonal winter ice road connects Inuvik with Tuktoyaktuk (approximately 195 km). Longer coastal ice roads were routinely built in the past (70's) to move heavy loads, for example to the McKinley Bay anchorage and marine base and to the anchorage in Herschel Basin off the Yukon Coast.

Tuktoyaktuk located on the north coast of the Mackenzie Delta, is closest to the Canadian Beaufort Sea offshore exploration areas. Historically, Tuktoyaktuk was used as a logistical base to support oil and gas activities in the 1970's and 80's, while Inuvik, with its year-round road access and scheduled jet passenger and airfreight service acted a major logistical hub for the area. Several other DEW line sites and camps, remnants of the cold war and previous exploration activities are located along the Yukon Coast, within the Delta and along Tuktoyaktuk Peninsula. Some of these sites could potentially be utilized as an intermediate storage, and helicopter staging/fueling centers to support an emergency spill response operation. The current condition of many of the abandoned airstrips may not support fixed wing aircraft operations without surveys and upgrading.

Aviation Infrastructure

Given the location of EL 460, Chevron will be investigating a suitable location from which to mobilize rotary wing and/or fixed wing aircraft.

Inuvik: The Inuvik Mike Zubko Airport (YEB) is a modern facility operated by the Government of NWT (Ministry of Transport) and is located 14 km from Inuvik. It has regular scheduled commercial flights from Calgary, Edmonton and Yellowknife. The airport has a 6000 ft (1829 m) paved runway that can accommodate IFR approaches, as well as terminal and cargo handling tools and equipment to unload large cargo airplanes. The runway can receive Lockheed C-130 Hercules and Boeing 737 class aircraft.

Tuktoyaktuk: The Tuktoyaktuk James Gruben Airport (YUB) is a year round airport with a gravel 5000 ft (1524 m) runway. Regular flights into Tuktoyaktuk airport come almost entirely from Inuvik and tend to be small regional commuter type aircraft operating under VFR flight rules.
There is a small passenger terminal and limited airport service. In an emergency, the runway could possibly receive a Lockheed C-130 Hercules (operated by CAF) or the L382 (civilian equivalent) and Boeing 737-200 series (with gravel kit), contingent on approval of runway conditions and the availability of suitable crash-rescue services.

Other airstrips: There are numerous other airstrip locations from previous industry activity that would be investigated for suitability when planning a potential offshore exploration drilling program.

Marine Infrastructure

Vessels and Sealift Operations

Existing marine equipment currently in the area is limited in capability and generally designed for close inshore operations.

In terms of routine summer resupply of heavy cargoes, the areas of the Mackenzie Delta and Beaufort Sea coast are serviced by a limited number of marine providers, with the most significant being Northern Transportation Company (NTCL). Marine fleets of most other operators in the area are dominated by river and inshore trading tugs and barges. An “Over the top” sealift from Vancouver via Point Barrow is available during the open water season, by a 15,000 tonne barge and tug system. Limited river barge operations continue to take place between Hay River and Inuvik while normal barge operations continue between Tuktoyaktuk and Inuvik. This is accomplished with a large number of deck and fuel barges ranging from 500 to 15,000 tons lift capacity, assisted by a variety of tugs. All of the marine equipment in the river operation is typically demobilized back to Hay River in late September.

Bases/Staging/Accommodation

Subject to marine vessel draft restrictions, potential marine bases for future emergency operations could include Tuktoyaktuk and McKinley Bay. Inuvik and Swimming Point are both located within the Delta and accessible only by shallow draft inshore barges and tugs.

Tuktoyaktuk Base camp is fully equipped with docks, warehouses, fuel storage (20 million liter capacity) as well as hotel services for 280 people. The camp has not been operated on a continuous basis in recent years, but could be reopened on short notice to support an emergency response operation. A major constraint in term of accessing the facilities in Tuktoyaktuk is the approach channel draft limitation. Vessel's draft cannot exceed 3 to 4 meters depending on wind direction and tide. Typically, the ice management fleet associated with deepwater operations will have deeper draft of approximately 8-9 m.

The McKinley Bay anchorage and the associated dredge spoil island offers a staging area and safe anchorage that can be accessed by deeper- draft vessels (up to 9m). Unfortunately, McKinley Bay is isolated with no year-round road access and no operational airstrip. It could be possible, as in the past, to construct an ice road to connect the anchorage with Inuvik and Tuktoyaktuk for a few months in the winter.

Responses to 1.5.1 (h), 2.7.1 (d) and 2.7.1 (e):

Table 1 summarizes some of key oceanographic and climatic differences between the Gulf of Mexico and the Beaufort Sea. In terms of bathymetry both regions encompass a broad range of water depths including large areas of shallow coastal areas and extensive river deltas (Mississippi, Mackenzie). The EL460 block acquired by Chevron in 2010 covers water depths from ~800 m in the south to 1700 m in the north. Approximately 20% of the Gulf of Mexico involves water depths greater than 3,000 m.

Table 1: Beaufort Sea vs. Gulf of Mexico Comparisons: mid to late October reference time period except as noted

PARAMETER	BEAUFORT	GULF OF MEXICO
DAYLIGHT	Inuvik: 11 hours	Galveston: 11 hours
DAYLIGHT June/December	24/0 hours	14/9 hours
OCTOBER DAILY TEMPERATURES (Min/Avg/Max)	Tuktoyaktuk: -10.9°C/-8.3°C/-5.6°C	Galveston: 20°C/27°C/31°C
ICE CONDITIONS	Open Water to 10/10ths ice concentrations	N/A
HURRICANES	N/A	Hurricane Season: Aug. – Nov.
STORM SURGE	Tuktoyaktuk Harbour: 0.5m (Large); 3.1 m (Extreme)	Extremes during major hurricanes (Ike, Katrina, Opal) 6.1 to 8.5 m
TIDES	Negligible (~ 0.1 m)	1.4 m tidal variation (typ Oct)
ICING	May occur	N/A
WIND SPEED	12.6 knots (mean) 38 knots (extreme)	14 knots (mean) >60 knots (extreme), 120+ hurricane
SIGNIFICANT WAVE HEIGHTS	1.5 m (Mean) 4 m (Extreme)	6-8 m non hurricane (Extreme) 11 m hurricane (Extreme)
CURRENT SYSTEMS	Beaufort Sea Gyre	Loop Current within Gulf Basin exits through Florida Strait forming Gulf Stream

Table data sources: Wind and Wave Heights for Beaufort: http://www.oceanweather.net/MSC50WaveAtlas/
Storm Surge: http://www.nhc.noaa.gov/ssurge/ssurge_overview.shtml
Tides and Currents US: http://tidesandcurrents.noaa.gov/gmap3/

The cold temperatures of the Arctic for much of the year place additional demands on both personnel and equipment. Personnel must be equipped with appropriate weather gear and Personal Protective Equipment (PPE) to deal with Arctic conditions. These are elements of incident response that are well known to the industry from decades of Arctic experience both on-land and offshore. Equipment would be housed according to suitability to Arctic operations, and adapted where necessary to deal with extreme cold temperatures that may be encountered in use or in storage. Indeed, adapting to the extremes of the local climatic conditions is a key part of response planning worldwide, whether it be -40°C in the Beaufort or +40°C in an equatorial region. Responder safety and response effectiveness during reduced daylight hours during winter months would be managed accordingly.

There is a vast amount of experience with marine crews operating for extended periods under Arctic conditions, winter and summer. In planning any Beaufort exploration program, Chevron would combine its in-house expertise through the Chevron Arctic Center with its corporate capability and the experience with local knowledge and involve people in the region who have great familiarity with operating in extreme climates. Response strategies are predicated on involving minimum exposure of personnel to severe environmental conditions. For example, primary strategies during freeze-up may involve a scenario such as subsea injection and ISB with limited requirements for any extended outdoor work. A primary strategy during break-up involves aerial ignition with IFR long-range helicopters based on icebreakers and operating during a period with close to 24-hour daylight under moderate temperatures.

Response to 1.5.1 (i):

The expected characteristics of the type of oil and the volume that could be released in a Beaufort Sea scenario will depend on a wide range of factors including those itemized in the CFI. These factors are specific to each drilling location and in the case of proposed future wells in offshore areas such as EL460, are either not publicly available or require further site investigations to determine. However, it is possible to use general information contained within public reports such as the one issued by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, as a basis for comparing deep water Gulf of Mexico exploration wells to a range of expected reservoir characteristics and drilling system designs applicable to the Western Beaufort Sea deepwater offshore area.

Looking at several key parameters it can be seen that there are features of anticipated Beaufort deep water exploration well design can be viewed as beneficial in terms of potentially reducing the size and/or rate of any major release, assuming Amauligak reservoir properties. For example:

- Less drilled depth from the mudline to target formation results in lower pore pressures within the reservoir.
- Lower porosity and permeability results in faster pressure depletion and higher drawdown (less flow).

Comparisons of other parameters such as geology (geothermal profile and sedimentary type), and drilling configuration (borehole size, riser size, and casing sizes) could result in neutral to positive outcomes for a Beaufort well depending on the specific well design.

In an overall comparison of the well parameters most likely to influence the severity of the release, a Beaufort exploration well appears to have many more neutral to positive outcomes than negative, using the Macondo well as a baseline example.

As a general statement, the type of oil that could be released is very site specific. The expected variation in the oil quality and its effect on a spill scenario can be taken into account in the well and incident response planning process prior to permit application. The volume of oil that could be released is again site specific and highly situation specific depending on the state of the wellbore at the time of the incident. The range of factors that would be used in estimating the volume of oil spilled would be the best available at the time including contingent planning for the required response capabilities to respond to the potential volumes. The blowout rate used for contingency planning purposes is jointly developed by the regulator and operator as part of the worst case scenario process as referenced in the Inuvialuit Final Agreement.

Basic weathering processes that applied to the spill in the Gulf of Mexico will also be experienced in a Beaufort Sea scenario: natural dispersion, dissolution, evaporation, and emulsification. The rates of these processes and ultimate oil fate will depend to a large extent on the actual oil properties, water depths, prevailing oceanographic conditions (primarily sea state and water temperature), surface atmospheric conditions (primarily wind speed and air temperature), extent of ice coverage and discharge conditions such as Gas Oil Ratio and discharge site. All of these variables, with the exception of ice, influenced the behavior of the oil released during the Macondo incident. Even with the relatively cold air temperatures anticipated in late October offshore in the Beaufort compared to the GOM (-8°C vs. +27°C) a substantial percentage of the surface slick would evaporate in a matter of hours. Natural dispersion on the surface during open water would be expected to occur at a similar rate during open water in the Beaufort as the GOM (for an equivalent sea state and oil viscosity).

In terms of oil behavior, both the Macondo well and Chevron's EL460 block are in deepwater well in excess of that required to encourage substantial gas hydrate formation (generally 800-900 m). In the absence of free gas driving a broad range of droplet sizes rapidly to the surface, oil from a deep-water blowout rises much more slowly. This permits a segregation of droplet sizes such that droplets of 100 microns or less will remain in suspension, leaving only the larger droplets to rise to surface. Depending on the surface water velocity and/or ice motion a deep water blowout can lead to substantial initial oil film thickness. This can be a positive aspect in terms of oil encounter rates needed for effective containment and collection for ISB for example.

Response to 1.5.1 (j):

Ice formation is a key feature of the Beaufort Sea late summer environment that will greatly affect the degree of environmental impact anticipated in any scenario where the spill occurs close to freeze-up in mid-October. By late September/early October a fringe of new fast ice will begin forming along much of the shoreline and by mid to late October, the shoreline will generally be protected from direct oiling by a band of ice extending out some distance from shore. Safety issues in offshore Arctic marine operations relate mostly to the risks of exposing workers to extreme temperatures for extended periods. These risks are mitigated by implementing response measures that involve minimal outside work – for example in situ burning from the air or subsea direct injection of dispersants/OMA. Please also refer to the responses provided for 1.5.1(h), 2.7.1(d) and 2.7.1 (e) for further discussion in this regard.

The Macondo response involved deploying hundreds of small vessels and many thousands of volunteers in potentially hazardous conditions dealing with hundreds of miles of oil boom under severe operating conditions of extreme heat and humidity. In contrast, this offshore scenario developed by Chevron for the Beaufort relies on a core group of highly trained marine and drilling specialists fully trained and equipped to work safely under the full range of Arctic temperatures expected. Any potential impact from oil spill response activities associated with a proposed offshore drilling project in the Beaufort Sea would be identified and assessed through the Environmental Assessment process.

Responses to 1.5.1 (k) and 1.5.1 (l):

The infrastructure and supporting systems (e.g., igniters, fire-resistant boom, dispersant, and tracking buoys) required to deal with a Tier 3 (major) incident in the deepwater offshore Beaufort will be sourced in advance and maintained in proximity throughout the exploration program as required to initiate the primary countermeasures strategies, in situ burning, subsea dispersant/OMA injection and oil tracking as soon as the site is cleared in terms of crew safety, rig integrity and subsea integrity (riser and BOP). See Section 1.4.1 for more discussion of well control activities under way as a prerequisite and in parallel with OSR. Agreements would be put in place as part of the drilling program oil spill contingency plan to provide for rapid deployment of airborne dispersant systems to work during any open water period preceding freeze-up. These high-volume delivery systems are kept in readiness to mount on several C-130's worldwide including in the UK (e.g. OSRL) and Alaska (e.g. Lynden). Positioning time to arrive in the Beaufort would depend on the originating point and flight times (typ. 5 to 24 hours). The first priority will always be safety of human life followed by well containment. Intensive response operations would be initiated only after evacuation, and rescue was executed successfully.

Responses to 1.5.1 (m) and 1.5.1 (n):

The basis for the scenario development is discussed in detail in Section 1.4.1 and within the *Chevron Canada*

Resources AODR Submission Part 1: Briefing Document, and based on a maximum spill duration of 10-14 days.

Response to 1.5.1 (o):

The final oil volume released could depend on a broad range of variables including geological and fluid properties, casing diameter, well depth and pressures, and the condition of subsea systems following the incident. Assuming a fixed flow rate, a major factor determining the release volume is the duration of the blowout. Chevron's approach to limiting this duration to every extent possible is described in the *Chevron Canada Resources AODR Submission Part 1: Briefing Document*. During the limited period of substantive oil discharge a range of OSR strategies will be employed to remove a significant percentage of the oil volume from the marine environment. These strategies are discussed within CFI 1.5.1(e) and 2.7.1 (a).

Response to 1.5.1 (p):

Clean-up efforts are initially focused on the near field response activities in the vicinity of the drill site while the release is underway. This operation lasting several weeks is followed by monitoring and tracking, looking for opportunities to remove any exposed oil during the winter, using a mix of dispersants, burning and limited mechanical recovery from icebreaking support vessels. This operation could continue for approximately six months from November to late April, at which point the oil trapped under the ice after freeze-up could become exposed in sufficient volumes and thicknesses to provide targets for aerial ignition.

Extensive helicopter-based ISB activities could extend into early July, at which point any oil still remaining would be dealt with at sea through controlled dispersant application (both ship-based and aerial). Deployment of booms at that stage (either for skimming or burning) is unlikely to be effective given the low oil concentrations and highly separated and fragmented thin slicks and sheens. At that point, any remaining response would focus on monitoring to direct countermeasures at oil which could threaten wildlife concentrations on the surface.

Response to 1.5.1 (q):

As part of any oil spill response plan called for under the approvals process for an exploration drilling program, the company would establish a training plan for all personnel that could be called on to participate in a response operation, both summer and winter. This may involve training local residents in assisting with any prestaging of equipment and participating in drills to handle the necessary equipment. At the time of a drilling permit application for an exploration drilling program, a complete training program would be developed as part of the oil spill response contingency plan. This would take into account the possible need to manage and train local and/or outside volunteers to cover all aspects of the response operation, offshore and onshore, through the full drilling season.

References

Alaska Regional Response Team, 2008. In-Situ Burning Guidelines for Alaska: Revision 1. Appendix II, Annex F, in The Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases.

Allen, A.A., 1999. New Tools and Techniques for Controlled In-Situ Burning. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 22, Vol. 2, pp 613-628. Environment Canada, Ottawa.

Allen, A.A., 1990. Contained Controlled Burning of Spilled Oil During the *Exxon Valdez* Oil Spill. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 13, pp 305-313. Environment Canada, Ottawa.

Arctic Report Card 2010 (www.arctic.noaa.gov/reportcard/)

ASTM, 2009. Annual Book of ASTM standards. American Society for Testing and Materials. West Conshohocken, PA.

Blenkinsopp, S.A., Sergy, G.A., Doe, K.G., Wohlgeschaffen, G.D., Li, K. and Fingas, M.F., 1997. Evaluation of the Toxicity of the Weathered Crude Oil Used at the Newfoundland Offshore Burn Experiment (NOBE) and the Resultant Burn Residue. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 20a: 677-684. Environment Canada, Ottawa.

Bronson, M.T., McAdams, F. and McHale, J., 2002. Mini Barge Shuttle Speeds in Ice. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 25, Vol. 2, pp 1367-1369. Environment Canada, Ottawa.

Buist, I., Potter, S., Sørstrøm, S.E. 2010. Barents Sea Field Test of Herder to Thicken Oil for *In Situ* Burning in Drift Ice. Proceedings 33rd Arctic and Marine Oilspill Program Technical Seminar, Halifax NS.

Buist, I., Potter, S., Nedwed, T. and Mullin, J., 2007. Field Research On Using Oil Herding Surfactants to Thicken Oil Slicks in Pack Ice for In-Situ Burning. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No 30, Vol. 1, pp 403-425. Environment Canada, Ottawa.

Buist, I., Dickins, D., Majors, L., Linderman, K., Mullin, J., Owens, C. 2003a. Tests to Determine the Limits to In Situ Burning in Brash and Frazil Ice. Proceedings 26th Arctic and Marine Oil Spill Program Technical Seminar, Vancouver.

Buist, I., T. Coe, D. Jensen, S. Potter, L. Anderson, K. Bitting and K. Hansen. 2003b. In-SituBurn Operations Manual. U. S. Coast Guard Research and Development Center Report CG-D-06-03, Groton, CT.

Buist, I.A., S.L. Ross, B.K. Trudel, E. Taylor, T.G. Campbell, P.A. Westphal, M.R. Myers, G.S. Ronzio, A.A. Allen and A.B. Nordvik. 1994. The Science, Technology and Effects of Controlled Burning of Oil Spills at Sea. MSRC Technical Report Series 94-013, Marine Spill Response Corporation, Washington, DC, 382 p.

Buist, I.A., Trudel, B.K., Morrison, J. and Aurand, D.V., 1995. Laboratory Studies of the Physical Properties of In-Situ Burn Residues. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 18, Vol. 2, pp 1027-1051. Environment Canada, Ottawa.

Buist, I., and D. Dickins, 1987. Experimental Spills of Crude Oil in Pack Ice. Proceedings of the 1987 International Oil Spill Conference, American Petroleum Institute, Washington.

Canatec Associates. Ice 06 Proprietary Database based on Canadian Ice Service ice charts.

Daling, P., Brandvik, P.J., Leirvik, F., Holumsnes, A., and C. Rasmussen. 2010. Development and field testing of a flexible system for application of dispersants to oil spills in ice. Proceedings 33rd Arctic and Marine Oilspill

Program Technical Seminar, Halifax NS, pp 787-814.

Daykin, M., Ga. Sergy, D. Aurand, G. Shigenaka, Z. Wang and A. Tang, 1994. Aquatic Toxicity Resulting from In-Situ Burning of Oil-on-Water. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 17b: 1165-1193. Environment Canada, Ottawa.

Dickins, D.F. 2011. Behavior of Oil Spills in Ice and Implications for Spill Response. Proceedings Arctic Technology Conference, Houston.

Dickins, D., Brandvik, P.J., Bradford, J., Faksness, L.-G., Liberty, L., Daniloff, R. 2008. Svalbard 2006 Experimental Oil Spill Under Ice: Remote Sensing, Oil Weathering Under Arctic Conditions and Assessment of Oil Removal by In-situ Burning. Proceedings 2008 International Oil Spill Conference, Savannah, Georgia.

Dickins, D.F., Buist, I.A. 1981. Oil and Gas Under Sea Ice Study: Vols. I&2. Prepared by Dome Petroleum Ltd. for COOSRA, Report CV-1, Calgary, AB, Canada (also published in Proceedings 1981 Oil Spill Conference, Atlanta GA).

Federal Interagency Solutions Group. Nov 2010. Oil Budget Calculator – Deepwater Horizon. Report to the National Incident Command (NIS).

Fingas, M.F., P. Lambert, Z. Wang, K. Li, F. Ackerman, M. Goldthorp, R. Turpin, P. Campagna, R. Nadeau and R. Hiltabrand, 2001. Studies of Emissions from Oil Fires. Proceedings of the Arctic and Marine Oil Spill Program Technical Seminar No. 24a:767-823. Environment Canada, Ottawa.

Fingas, M.F., G. Halley, F. Ackerman, R. Nelson, M.C. Bissonnette, N. Laroche, Z. Wang, P. Lambert, K. Li, P. Jokuty, G. Sergy, W. Halley, J. Latour, R. Galarneau, B. Ryan, P.R. Campagna, R.D. Turpin, E.J. Tennyson, J. Mullin, L. Hannon, D. Aurand and R. Hiltabrand, 1995b. The Newfoundland offshore burn experiment. Proceedings 1995 International Oil Spill Conference, pp 123-132. American Petroleum Institute. Washington, D.C.

Gulec, I. and D.A. Holdway, 1999. The Toxicity of Laboratory Burned Oil to the Amphipod *Allorchestes Compressa* and the Snail *Polinices Conicus*. Spill Science & Tech., V. 5, pp. 135-139.

Lee, K.Z., B. Robinson, P. Kepkay, B. Doyon and M. Blouin. 2010. A field evaluation of dispersion treatment efficacy of oil spill on ice-infested waters by enhancing formation of oil-mineral aggregates. Draft manuscript produced by Centre for Offshore Oil, Gas and Energy Research, Fisheries and Oceans Canada, Dartmouth, NS and Canadian Coast Guard, Quebec City, QB.

Lee, K. Z. Li, B. Robinson, P. Kepkay, X. Ma, S. Cobanli, T. King, M. Blouin and B. Doyon, 2009. In-situ Remediation of Oil Spills in Ice-Infected Waters: Oil Dispersion by Enhancing Formation of Oil-Mineral Aggregates. Proceedings of Interspill 2009. Marseille, May 12 to 14.

McGrattan, K.B., Walton, W.D., Putorti, A.D., Twilley, W.H., McElroy, J. and Evans, D.D., 1995. Smoke Plume Trajectory from In-Situ Burning of Crude Oil in Alaska – Field Experiments. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 18, Vol. 2, pp 901-913. Environment Canada, Ottawa.

Newfields and University of Alaska. 2010. Memorandum - Joint Industry Program to Evaluate the Effects of Dispersed Oil on Cold Water Environments of the Beaufort and Chukchi Seas.

Norcor. 1975. The Interaction of Crude Oil with Arctic Sea Ice. Beaufort Sea Project Technical Report No. 27, Canadian Department of Environment, Victoria, BC, Canada.

Owens, C. and Belore, R., 2004. Dispersant Effectiveness Testing in Cold Water and Brash Ice. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 27, Vol. 2, pp 819-841. Environment Canada, Ottawa.

Potter, S. and I. Buist. 2010. *In-situ* Burning in Arctic and Ice-covered Waters: Tests of fire-resistant booms in low concentrations of drift ice. Proceedings 33rd Arctic and Marine Oilspill Program Technical Seminar, Halifax NS, pp 743-754.

Preli, T., A.A. Allen and D. Glenn. 2011. Development of High Speed Aerial Ignition Techniques for In Situ Burning. Proceedings Arctic Technology Conference, Houston.

Ross, J. L., R. J. Ferek and P. V. Hobbs. 1996. Particle and Gas Emission from an In-Situ Burn of Crude Oil on the Ocean. Journal of the Air and Waste Management Association: 46 251-259.

Trudel, K., S. Ross, R. Belore, S. Buffington, G. Rainey, C. Ogawa and D. Panzer, 2003. Technical Assessment of Using Dispersants on Marine Oil Spills in the U.S. Gulf of Mexico and California. Proceedings of the 2003 International Oil Spill Conference. American Petroleum Institute, Washington.

Trudel, B.K., 1988. Guide to Dispersant-Use Decision Making for Oil Spills in the Canadian Southern Beaufort Sea. Environmental Studies Research Funds, Publication No. 092, 227 pp.

Nedwed, Tim, Gerard P. Canevari, James R. Clark and Randy Belore, 2008. New Dispersant Delivered as a Gel. Proceedings of the 2008 International Oil Spill Conference, American Petroleum Institute, Washington.

Nedwed, T., Spring, W., Belore, R. and Blanchet, D., 2007. Basin-Scale Testing of ASD Icebreaker Enhanced Chemical Dispersion of Oil Spills. Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 30, Vol. 1, pp 151-160. Environment Canada, Ottawa.

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. Calgary. 126p.

SL Ross Environmental Research Ltd., 2007. Net Environmental Benefit Analysis of Dispersants for Cleaning Oil Spills from Production Platforms on the Newfoundland Grand Banks. Report prepared for the Canadian Association of Petroleum Producers, Calgary.

S.L. Ross Environmental Research, 1998. Identification of Oils That Produce Non-Buoyant In-Situ Burning Residues and Methods for Their Recovery. American Petroleum Institute and the Texas General Land Office, Washington, DC, 50 pp.

SL Ross Environmental Research Ltd. and DF Dickins Associates Ltd. 1987. Field Research Spills to Investigate the Physical and Chemical Fate of Oil in Pack Ice. ESRF Report No. 062. Ottawa. 118p.

Sørstrøm, S.E., P.-J. Brandvik, P.J., Buist, I., Daling, P., Dickins, D., Faksness, L.-G., Potter, S., Rasmussen, J.F., Singsaas, I.. 2010. Joint Industry Program on Oil Spill Contingency for Arctic and Ice-covered Waters: Summary Report. Oil in Ice JIP Report No. 32, SINTEF, Trondheim, Norway.

SCOPE ITEM #6 – EFFECTIVENESS AND RELIABILITY OF OPTIONS FOR REGAINING WELL CONTROL, INCLUDING RELIEF WELLS

1.6.1 *Relief Wells, Including Same Season Relief Well Capability*

Context: Paragraph 5(1)(b) of COGOA requires that companies obtain a project-specific authorization for a proposed work or activity. Paragraph 6(j) of the Drilling and Production Regulations states that the application for authorization shall be accompanied by: contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection . . .

In the Drilling and Production Regulations, the onus is on the operator to develop the contingency plans appropriate for its proposed project, taking into account anticipated hazards and risks, and identifying appropriate equipment, procedures and personnel. A relief well is one contingency measure employed to respond to loss of well control. In Arctic offshore the NEB has a policy that the operator demonstrate within its contingency plan relief well capability to kill an out of control well during the same drilling season. This is referred to as same season relief well capability (SSRW). The Drilling and Production Regulations require that the contingency plans accompany the application for an authorization. The NEB considers the adequacy of the plans on a project by project basis at the application stage. The plans can also be considered during any environmental assessment process conducted for the proposed project.

Request:

In identifying the measures to be included in contingency plans, describe:

(a) how, at the project planning stage, reasonably foreseeable events would be identified for offshore wells in the Arctic. Describe how loss of well control is considered in this evaluation;

(b) what methods and options are available to meet the same season relief well capability and what factors need to be considered to ensure that this is achieved;

(c) the effectiveness of these methods and options identified in response to (b) and under what circumstances encountered in the Arctic they would not be effective;

(d) how measures to *prevent* loss of well control, as well as other methods to regain well control, would be considered in making the decision to use any of the methods and options identified in response to (b);

(e) a typical sequence of response measures to regain control of a well, and identify where the drilling of a relief well would fit within this sequence;

(f) what factors are considered when determining when to initiate the drilling of a relief well; and

(g) what would be required for a relief well to be completed within the season that the loss of well control occurred considering a range of water and drilling depths.

Response to 1.6.1 (a):

In addition to the Drilling and Production Regulations, Chevron's well planning worldwide is governed by our Operational Excellence Well Design and Construction Process which mandates a range of procedures and standards to identify, mitigate and manage risk, to ensure that the planning process is rigorous and operations are carried out safely and with care for the environment.

Chevron conducts internal peer assists during the planning phase of all our wells. This is a formal approach to review well design and execution of drilling, completion and abandonment carried out by subsurface, drilling and completion professionals not associated with the project to ensure objective review.

In terms of a loss of well control, the preparation of an Oil Spill Contingency Plan requires the Operator to address this issue at the project planning stage prior to receiving drilling program approval. The Operator develops a loss of well control operating philosophy and then generates a Contingency Plan to address such loss of well control.

Chevron's key objectives in such a Contingency Plan are how to regain well control, stop the flow of hydrocarbons, and reduce the duration of a spill, thus mitigating the impact on the environment.

Please also refer to Sections 1.1.2, 1.4.1 and 1.10.1(b) for discussion of how reasonably foreseeable events would be identified for offshore wells in the Arctic, where a key focus of the overall well planning process is to prevent a loss of well control from occurring. As outlined within these Sections, the various Chevron processes applicable to the identification of reasonably forseeable events include, but are not limited to:

- Risk Uncertainty Management System (RUMS)
- Single Well Chevron Project Development & Execution Process
- Subsurface Management of Change
- Well Examination and Verification
- Incident Free Operations Plan
- Peer reviews

Response to 1.6.1 (b):

Chevron supports the response provided by CAPP in this regard.

Response to 1.6.1 (c):

The methods and options discussed here include use of a technology such as the Chevron AWKS; a relief well; or pre-engineered alternatives to a relief well such as a capping BOP.

Relief Wells
The effectiveness of a relief well drilled from a floating rig in the Canadian Beaufort Sea will be largely governed by:

- when it occurs in the drilling season;
- the well depth and complexity;
- the ice conditions expected throughout the relief well operating period; and
- the station-keeping parameters of the drillship and the number, capability and ice class of the marine support vessels.

As discussed within the *Chevron Canada Resources AODR Submission Part 1: Briefing Document*, a relief well operation may comprise many Secure Time (ST) operations as defined in the Ice Alert procedures section. Thus, as pack ice concentrations and severity increase, especially in the scenario of a late season blow-out, drilling efficiency will likely decrease for a given number and capability of ice management vessels and drillship.

The conditions under which SSRW is no longer a viable option have been provided within the *Chevron Canada Resources AODR Submission Part 1: Briefing Document;* and the Chevron Submission to the *National Energy Board Policy Hearing for Same Season Relief Well Capability for Drilling in the Beaufort Sea (March 22nd 2010),* which indicate that when the original well takes more than one operating season to drill, the ability to meet the SSRW requirement is likely in question.

Capping BOP or Alternate Pre-engineered System
Chevron has evaluated other well secure options for use in the deeper water regions of the Beaufort Sea, and the use of a capping BOP or alternative appears applicable. Unlike the relief well option, most of the time associated with the deployment of such a system does not require the tight continuous station-keeping requirements that are necessary in the drilling mode. The capping BOP connection and well shut-off operation involves connecting to the original drilling BOP on the seafloor and could take place as quickly as hours, or as long as several days. With appropriate levels of ice management support, this operation can be performed at almost any time of the year on the Canadian Beaufort Slope unlike the relief well option. In significant levels of pack ice cover, allowances should be made to wait for an appropriate window when the completion of such an operation has the highest degree of reliability.

Response to 1.6.1 (d):

As discussed previously, both Chevron's project planning management system and the regulatory process require Chevron to develop a loss of well control operating plan. Such a plan addresses well control; methods to regain well control in the unlikely event that such should occur; and measures to minimize the size and impact of any resultant spill. An example of such an approach is outlined in the *Chevron Canada Resources AODR Submission Part 1: Briefing Document* under the section titled *A Goal Based Approach to Same Season Relief Well (SSRW) Capability*. This example illustrates an all encompassing approach that addresses both risk and consequence in a logical and pre-engineered manner.

Response to 1.6.1 (e):

Chevron's preliminary determination is that a relief well is not the best primary intervention option available. A relief well by its very nature will likely result in a larger spill than would occur through the use of a capping BOP or alternate pre-engineered system. A late season relief well will be subject to station-keeping inefficiencies imposed upon it through the application of the Ice Alert Procedures.

A restatement of the SSRW capability requirement goal allows a two-step well secure option, namely:

1. Stop the flow and secure the well
2. Treat the well kill as a separate operation

Such a restatement of the SSRW goal allows the use of a capping BOP or alternate pre-engineered system which provides the following benefits:

- A shorter duration of uncontrolled flow and reduced volume of released hydrocarbons
- A lower Secure Time and higher reliability operation
- Increased operating window to undertake the well kill operation
- With the well secured with a capping BOP or alternate pre-engineered system installed there are many other forms of direct well intervention available that may not require a relief well to kill the well

Such a goal based approach urges a focus on minimizing the duration of the uncontrolled flow. Well design, equipment and procedures that allow operators to reduce the well flow duration to levels significantly less than would be the case for a relief well represent a major step forward in terms of safety, conservation of the resource and protection of the environment. For further discussion in this regard, please refer to the section of the *Chevron Canada Resources AODR Submission Part 1: Briefing Document* titled *A Goal Based Approach to Same Season Relief Well (SSRW) Capability.*

Response to 1.6.1 (f):

As discussed, Chevron feels that a relief well is not the best primary well intervention method. Use of a capping BOP or alternate pre-engineered system may preclude the need for a relief well completely. While a relief well may be required as part of an overall contingency plan, in general it should only be completed after the hydrocarbon flow has been stopped, the well safely secured, and all of the direct well kill intervention methods attempted without success.

Response to 1.6.1 (g):

The duration and ability to drill a relief well is primarily related to drilling depth, complexity, and ice conditions, not water depth. The ability to drill and complete a relief well within, for example, the winter drilling season, is related to the station-keeping capability of the drill system. This, in turn is related to the station-keeping capability of the drillship, whether moored or dynamically positioned, and the effectiveness of the ice management system.

Theoretically, if the capability of both of these components is increased it will substantially increase the drilling season, albeit at likely reduced operational effectiveness.

Fundamentally, as stated in the *Chevron Canada Resources AODR Submission Part 1: Briefing Document*, a relief well may potentially result in a much larger spill than would occur through the use of the latest technology, equipment and procedures in a pre-engineered form, such as via the use of a capping BOP or alternate pre-engineered system. For these reasons, Chevron strongly supports the redefinition of the underlying goal to the SSRW requirement, as outlined in the *Chevron Canada Resources AODR Submission Part 1: Briefing Document*, thus removing the necessity to utilize a relief well as primary means of the stopping the flow and safely securing the well.

1.6.2 *Regaining Well Control*

Context: Regaining well control is essential for safety and protection of the environment. Subsection 6(j) of the Drilling and Production Regulations requires applicants for an authorization to provide: contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection... Section 19 of the Drilling and Production Regulations requires that: operators take all reasonable precautions to ensure safety and environmental protection… An operator is, by definition, the holder of the authorization and operating licence. Section 38 of the Drilling and Production Regulations states that: If the well control is lost or if safety, environmental protection or resource conservation is at risk, the operator shall ensure that any action necessary to rectify the situation is taken without delay, despite any condition to the contrary in the well approval. Loss of well control may include blow-out at surface, an uncontrolled underground flow of fluids from one formation into another, releasing of fluids at the seafloor or any other loss of well control.

Request:

(a) What criteria would be used to select the appropriate contingency measure to regain well control during Arctic offshore well operations?

(b) What would be the feasible methods to intervene to regain control of a well in the Arctic offshore and why?

(c) For each measure described in (b), describe the sequence in which these measures would be implemented and the time it would take to implement each of these measures.

(d) How would operations and resources, including equipment and trained personnel, be integrated within the management system to address reliability and effectiveness of emergency response plans?

(e) What lessons have been learned from the Gulf of Mexico BP Deepwater Horizon incident for regaining well control that could be applied in the Arctic?

(f) What emerging technologies for regaining well control in Arctic offshore drilling operations are expected to become available, in the next three to five years, and how would the effectiveness and reliability of these technologies be evaluated?

Response to 1.6.2 (a):

The methods used to regain well control in the Arctic are not different from the methods used in other deepwater offshore locations. The criteria used to select a well control method would depend on the nature and severity of the situation. Important considerations in the early stages of a blowout include ensuring personnel safety, minimizing damage to the well, structures, and environment, and preventing any escalation of the situation:

1. Safety of personnel – the priority in securing the well would be to deal with the potential exposure of personnel and not increase the hazard during intervention operations.
2. Protection of the environment – consideration would be given to securing the well as quickly as possible to reduce the volume and duration of the release.
3. Conservation – the method selected would consider the potential for long term effects on the recovery of the resource.

Well control scenarios are evaluated during the risk and uncertainty management process, and the appropriate mitigation measures and contingencies developed. These would include:

- procedures,
- equipment selection,
- training and competency requirements, and
- control measures to reduce the likelihood or escalation in a well control incident.

Response to 1.6.2 (b):

This would depend on the circumstances of the situation encountered. As discussed within the *Chevron Canada Resources AODR Submission Part 1: Briefing Document,* and within the response provided for CFI 1.4.1, the well control methods used in the Arctic are the same as conventional drilling operations. Conventional drilling methods include circulating or pumping high density mud into the well, placement of additional mechanical barriers, and activation of the BOP. New methods are being developed for well control including the AWKS and a capping BOP stack installed after a well control incident.

Response to 1.6.2 (c):

The methods used to regain well control in the Arctic are not different from the methods used in other deepwater offshore locations. Some methods are more amenable to station keeping in ice conditions, but the operating season window would place a priority on methods that can be accomplished reliably within the remaining window. During the planning of the well, a risk assessment would be completed to determine the appropriate well design, equipment selection, contingencies plans and procedures, training and competency requirements, with an emphasis relative to the expected Arctic conditions. Included in this planning is the redundancy and backup of the essential capabilities to carry out any planned well intervention, even in the case where the drill ship may be disabled.

In general order of application, the following methods for regaining well control would typically be used including, but not be limited to:

1. Re-establishment of hydrostatic control through circulation placement of heavier fluid in the wellbore using the drill string. Duration: hours, no release.
2. Re-establishment of hydrostatic control through bullheading or displacement through the choke and kill lines. Duration: hours, no release.
3. Through pipe intervention to reduce inflow and then re-establish hydrostatic control. Duration - approximately 1 day, no release.
4. Activate the BOP. Duration: minutes, no release.
5. In the event of BOP failure and blowout, placement of a capping BOP stack or alternate pre-engineered system on to the well using the drill ship. Same well intervention procedures would follow. Duration: 3 to 5 days, release of approximately 3 to 4 days.
6. In the event of the disabling of the drill ship, placement of a capping stack with BOP by the auxiliary support vessel/nearby drillship. Same well intervention procedures would follow. Duration: 10 to 15 days (inclusive of ice and weather downtime), release of 10 to 15 days.

These control methods would be implemented with equipment, personnel, and material readily available at the time the well is drilling. Subsequent to stopping the well flow, if the well cannot be killed and permanently abandoned due to equipment limitations or seasonal restrictions, then at a minimum the well will be safely secured for abandonment the following season.

Response to 1.6.2 (d):

Chevron Canada’s Emergency Response Organization is manned by Chevron company employees and contractors based in Canada. This team can be supplemented by Chevron’s World Wide Emergency Response, Functional, and Regional Teams as well as contractor resources located inside and outside Canada.

Chevron’s Emergency Management process is based on the Incident Command System (ICS). Under ICS, five major functions have been identified that serve as the foundation of the organization -- Command, Operations, Planning, Logistics, and Finance. Under ICS, the Command Staff is composed of Officers and the General Staff consists of Section Chiefs.

Prior to being granted an operating authorization, appropriate plans necessary to address the ability to respond to an emergency are developed. These plans are developed with the goal that preventing incidents is the first priority, and then outlines what steps will be engaged in the event of an incident.

An emergency response plan, oil spill response plan and a well blow-out contingency plan are all separate plans that are prepared, reviewed and submitted for approvals. Well control training and certification is also ensured prior to commencing any drilling programs.

Emergency Response Plan
The emergency response plan sets out to provide clear and concise guidance for emergency support actions to be taken under all emergency scenarios that could reasonably be expected to occur during the drilling program.

Procedures to ensure the Local Emergency Operations Centre (LEOC – the center from where the emergency will be managed) is appropriately staffed as soon as possible after the occurrence of an emergency and that all necessary support (i.e., technical, media, family, regulatory liaison, logistics, etc.) is provided to the facility or location experiencing the emergency are set out in the emergency response plan.

Blow-out contingency plan (BCP)
Procedures for handling emergencies are absolutely essential to ensure the protection of life, property, and the environment. This document describes the procedures that are followed if a well control emergency was encountered during operations. The primary focus of the BCP is to:

- Prevent further damage or injury while adequate equipment and personnel are being mobilized
- Reduce response time for a major well control intervention project by proactively identifying the equipment needed and sources for the equipment
- Reduce overall event time by determining and planning for critical issues in advance

Oil Spill Response Plan (OSRP)
The oil spill response plan is developed to ensure that Chevron maintains the capability for an immediate response to an oil spill incident occurring during drilling operations. This includes the equipment available and the necessary contractual agreements in place with oil spill response corporations.

Well Control
Chevron believes in a proactive approach to well control and considers it the foundation of our drilling and completion activities. Well control is approached with the mindset that all of our employees and contractors must be made aware of their role as well as the impact of a failure to execute well control effectively. The Company has established a Drilling and Completions Training Center in Houston Texas that has provided well control schools and expertise support for the past 40 years. Also formed within Chevron is a subsea blow-out preventer specialist team who provide support to Chevron drilling and completion activities worldwide.

Personnel
Chevron has recognized the importance of drilling superintendents, drill site managers (DSM's) and field drilling engineers (FDE's) in our operations. Our goal is to continue to grow capacity of our front line leaders as they are critical to the success of our operations. Competent on-site leadership is important and having strong technical and operational knowledge in the field is critical to preventing incidents.

Within Chevron drilling and completion there are two networks: The Drilling Network and Completion Network. Both networks are highly effective discussion networks that serve to share knowledge across a very wide cross section of our organization, including topics of well control, well design, equipment etc. as well as health, environment and safety. These networks have helped with incorporating various best practices and lessons learned into well design and operating practices.

Management System Standards
Risk and Uncertainty Management (RUMS) and Management of Change (MOC) are two methods utilized within Chevron drilling and completion when conducting well planning (refer to Section 1.1.2 and 1.10.1(b)). These are methods developed to ensure wells are designed to maintain well control and must consider all possible outcomes

during the life of the well. These methods were also developed with the goal of ensuring wells have sufficient tested barriers in place before removal of the rig's safety systems.

Stop Work Authority (SWA)
Before engaging in any drilling activity, Chevron ensures that all crews understand and practice their roles in a well control situation. The basic philosophy is – "When in doubt, shut the well in". If there is a potential well control situation or an emergency, there may not be time to stop and write down the plan. Everyone involved with operations has responsibility for shutting down any operation if there is any concern. Personnel are encouraged to exercise stop work authority at any time without asking for permission and without fear of repercussion. Work must also not be allowed to re-commence until all concerns raised have been thoroughly resolved and the operation is confirmed safe to proceed.

Response to 1.6.2 (e):

Awareness of well control hazards and safety management processes has been heightened after the Macondo incident. Chevron has examined its internal safety procedures with respect to the findings of the investigations, and reinforced where necessary. The Macondo incident also illustrated that a relief well may not be the most effective measure relative to other alternatives (i.e., capping BOP) for a subsea blowout.

Response to 1.6.2 (f):

Initially, the emerging technologies are expected to focus on preventing an uncontrolled flow from a subsea blowout. Chevron and Cameron are jointly developing the AWKS as described in Chevron's submission to the NEB Same Season Relief Well Review as one such measure to enhance BOP performance. A capping BOP stack or alternate pre-engineered system would provide an alternative means of stopping the flow from a failed subsea BOP.

These systems will be tested according to established standards (e.g. API Spec 16a for BOPs). Other certifying bodies may develop or extend protocols for testing and certification of new offshore equipment and systems.

Chevron will comply with any regulations that are in place at the time of approval. Regulations that are goal based will not limit the application of new technology where the technology is proven and tested to provide a level of protection that meets or exceeds the stated goals.

SCOPE ITEM #8 – FINANCING SPILL CLEAN-UP, RESTORATION AND COMPENSATION FOR LOSS OR DAMAGE

1.8.1 *Financial Liability*
Context*:* Subsection 25(3) of COGOA states that: Every person required to report a spill under subsection (2) shall, as soon as possible, take all reasonable measures consistent with safety and the protection of the environment to prevent any further spill, to repair or remedy any condition resulting from the spill and to reduce or mitigate any danger to life, health, property or the environment that results or may reasonably be expected to result from the spill. Section 26 of COGOA indicates that where any spill occurs, the operator is liable, without proof of fault or negligence, up to any prescribed limit of liability, for all actual loss or damage incurred by any person as a result of the spill. The *Inuvialuit Final Agreement* indicates that where it is established that actual wildlife harvest loss or future harvest loss was caused by, among other things, the extraction of non-renewable resources from the Beaufort Sea, the liability of the developer [operator] shall be absolute.

Request:
(a) For each of the scenarios discussed under request 1.5.1, please provide estimates of the costs listed in (i) to (vi) below. Describe how each estimate was arrived at, including any assumptions that were made in its calculation and provide a discussion on the reliability of these estimates.

> **(i) costs incurred to prevent any further spill;**
> **(ii) cost incurred to repair or remedy a condition resulting from the spill, including costs related to actions required to remove or recover debris;**
> **(iii) cost incurred to reduce or mitigate any danger to life, health, property or the environment that results or may reasonably be expected to result from the spill;**
> **(iv) the amount of actual loss or damage of those affected by the event;**
> **(v) the amount of actual wildlife harvest loss and/or future harvest loss; and**
> **(vi) the cost to mobilize a suitable drilling platform and personnel to drill a relief well.**

(b) Please discuss whether these cost estimates are additive or whether there is an overlap between some of the categories which would render a simple summation of them inappropriate.

Responses to 1.8.1 (a) and 1.8.1 (b):

Estimates of the costs for the scenarios set out above are well program specific and would be dealt with as part of a specific well application. It is not possible to provide an accurate estimate of such costs in the abstract without knowing the particulars of the planned well operation. Factors such as water depth, well depth, geological zones anticipated to be encountered, type of hydrocarbons anticipated, volumes of a spill, timing of the well control event, the drilling system and the support equipment involved and any specialized equipment designed to regain well control, etc., are all relevant to calculation of these costs.

The most important factors in terms of cost associated with a spill are the duration (amount of time required to regain well control, stop the flow of hydrocarbons and thus prevent any further spill) and the resultant magnitude of a spill (in terms of clean-up and possible damage to wildlife /third parties). If these factors can be limited, then the effects and costs of managing and remediating a spill can be significantly mitigated. As noted in our submission, use of a capping BOP or some other pre-engineered system may be a more efficient and effective means of regaining well control and preventing any further spill than a relief well. It is also our position that with the use of such equipment that well control can be regained safely within the same drilling season and the magnitude of a spill can be accordingly limited in duration. Further, the use of dispersants during a spill and burning of oil on surface can significantly reduce the effects of a spill and potentially reduce any resulting losses to third parties. See section 1.5.1 and 2.7.1 for additional details in this regard.

Chevron does not believe that a simple summation of each of the costs set out in (i) to (vi) gives an accurate reflection of the total costs. Our view is that these costs are not additive and that there is definitely overlap between a number of the elements described above. For example there is some degree of overlap between (ii) and (iii) (remedying conditions resulting from the spill, including clean up of the spill and any debris), (iv) and

(v) (compensating those who incurred loss or damage resulting from the spill) and (i) and (vi) (regaining well control and stopping the flow of hydrocarbons).

In relation to item (vi), again we see the underlying assumption that this is the primary method to regain well control and prevent any further spill. A relief well may or may not be part of the part of the overall solution. We would respectfully restate this objective of (vi) to be “costs to mobilize suitable equipment capable of regaining well control and stopping the flow of hydrocarbons” or words to that effect. The cost of this suitable equipment may already be included as part of the overall drilling system, so again the cost may not be additive, albeit there would be additional costs related to the time required to regain well control and implement all remedial action required.

An integral part of any drilling authorization is an Oil Spill Contingency Plan. This requires an Operator to anticipate the worst case scenario and have a detailed plan in place, including appropriate equipment and procedures to deal with all aspects of a well control event. This plan must be reviewed by the Board and, if acceptable, is then approved by the Board. If the measures proposed are inadequate the Board will not grant the drilling authorization. It is our submission that where detailed advance planning is in place that the costs related to items (i) through (vi) will be significantly less than where such measures are not in place.

1.8.2 ***Financial Responsibility***

Context: Subsection 27(1) of COGOA states that: An applicant for an authorization under paragraph 5(1)(b) in respect of any work or activity in any area in which this Act applies shall provide proof of financial responsibility in the form of a letter of credit, a guarantee or indemnity bond or in any other form satisfactory to the National Energy Board, in an amount satisfactory to the Board.

Request:

(a) Please describe how the amount of financial responsibility should be determined for a proposed Arctic offshore drilling project. Please discuss the extent to which the cost estimates discussed in the responses to request 1.8.1 above would be considered in this determination.

(b) Please describe the type of information, and level of details thereof, that would be appropriate at the application stage to demonstrate financial responsibility with respect to offshore drilling in the Arctic.

(c) Please discuss the pros and cons, for the applicant and for the Board, of each form of proof of financial responsibility referred to in subsection 27(1). In responding, please include any other form not specifically mentioned in subsection 27(1) that would be appropriate.

Responses to 1.8.2 (a), 1.8.2 (b) and 1.8.2 (c):

Chevron supports the responses provided by CAPP in this regard.

SCOPE ITEM #9 – STATE OF KNOWLEDGE OF LONG TERM IMPACTS OF A SPILL ON THE ENVIRONMENT, WAY OF LIFE AND COMMUNITIES IN CANADA'S ARCTIC

1.9.1 *State of Knowledge of Long Term Environmental and Socio-Economic Impacts*

Context: Studies commissioned by the Exxon Valdez Oil Spill Trustee Council describe environmental and socio-economic impacts which continue some 20 years after the event. Concerns have also been raised regarding the long term effects of the Gulf of Mexico BP Deepwater Horizon incident. Subsection 5 (1) of *Canadian Environmental Assessment Act* requires an environmental assessment (including effects on socio-economic conditions) for proposed projects in most of the Inuvialuit Settlement Region (including the Beaufort Sea) and Davis Strait/Baffin Bay, Hudson Bay and James Bay outside of the Nunavut Settlement Area. Development impacts in the Inuvialuit Settlement Region are also assessed under the *Inuvialuit Final Agreement*. In the Nunavut Settlement Area, development impacts are assessed solely under the *Nunavut Land Claims Agreement*.

Request:

(a) Please discuss what is considered to be the best available information assessing the short and long term environmental and socio-economic impacts of oil spills on Arctic people, their communities, and the natural environment. Indicate what criteria were used to select this information.

(b) Please discuss what is considered to be the best available knowledge of the effects of climate change on Arctic oil and gas exploration and operations. Indicate what criteria were used to select this information.

(c) Please provide an assessment as to the adequacy of the best available information provided in response to (a) and (b) above. Discuss whether the available information adequately addresses regional differences such as those between the eastern and western Arctic as well as between coastal, continental shelf, and deep waters. Also, please provide an assessment as to the adequacy of the best available information sought in paragraphs (a) and (b) above in the light of an incident of the magnitude of the Gulf of Mexico BP Deepwater Horizon incident. Specifically, what unique biophysical features in the Arctic would be particularly sensitive to a major oil spill?

(d) Please discuss whether the current level of knowledge needs to be advanced. If so, please indicate in what ways the level of knowledge could or should be advanced, and how, when, and by whom this might best be done. Include a discussion of on-going initiatives and how these may contribute to the current or future level of knowledge.

Responses to 1.9.1 (a), 1.9.1 (b), 1.9.1 (c) and 1.9.1 (d):

Chevron supports the responses provided by CAPP in this regard.

SCOPE ITEM #10 – LESSONS LEARNED FROM ACCIDENTS, INCIDENTS AND EMERGENCY RESPONSE EXERCISES, PARTICULARLY THOSE RELEVANT TO NORTHERN OFFSHORE ENVIRONMENTS

1.10.1 *Learning from Incidents and Near-misses*

Context: In many international offshore oil and gas jurisdictions, when there is an incident in which there is loss of well control, an investigation is conducted and an investigation report completed. Such reports often contain a description of the incident, its causes (root and contributing) and may contain recommendations that may be made available to companies and to the public. Section 75 of the Drilling and Production Regulations requires operators to ensure that every incident and near-miss related to the authorized work or activity, including the loss of containment of any fluid from a well, is investigated, its root cause, contributing and causal factors identified and corrective action taken. The Drilling and Production Regulations also require operators to identify hazards and evaluate and manage associated risks and to ensure that the documents associated with their management system are current and valid. The Drilling and Production Regulations also require operators to take all reasonable measures to ensure safety and environmental protection.

Request:

(a) Please describe the lessons learned from incidents that have occurred in the oil and gas offshore industry and, where lessons are applicable, onshore and other industries. Include preliminary findings and lessons that have been revealed in recent incidents and through the ongoing inquiries and reviews such as those listed in Appendix D of the NEB's letter dated 20 September 2010

(b) Please describe how incident and near-miss reports (either your own or from others) would be used in the planning and operations phases of a project and the continuous improvement of management systems, including how they contribute to:

- **(i) hazard identification and risk evaluation;**
- **(ii) design;**
- **(iii) equipment selection;**
- **(iv) development or modification of procedures and plans; and**
- **(v) selection and training of personnel.**

Response to 1.10.1 (a):

Chevron supports the response provided by CAPP in this regard.

Response to 1.10.1 (b):

As part of OEMS, Chevron has a global standard process for Incident Investigation and Reporting (II&R), with an objective to investigate and identify root causes of incidents to reduce or eliminate systemic causes and to prevent future incidents. II&R provides a process to report, record and investigate incidents and near misses and correct any deficiencies found. This process also includes:

- Management roles and responsibilities in incident investigation.
- Root cause analysis for significant events and near misses.
- Annual evaluation of incident cause trends to determine where improvements in systems, processes, practices or procedures are warranted.
- Sharing of relevant lessons learned.
- Procedures for follow-up and closure of actions taken to resolve deficiencies.

All Operations within Chevron, including contractors working within Chevron's operational control, are expected to comply with this requirement.

Continuous Improvement
Chevron has a set procedure for sharing of lessons learned from incident investigations, trend analysis and the use of a database tool for the management of incident information.

Major incidents that occur outside of Chevron operations are reviewed at a corporate level to determine relevance to Chevron operations. Learnings from the incidents are then incorporated into the Chevron OEMS as appropriate.

Chevron Corporate Requirements – Major and Catastrophic Events:

If Reports
If Reports are used across Chevron's global operations to share lessons learned from any type of OE incident in a simple one page format. The If Report describes what happened; what went wrong; and what can be done to avoid repeating similar incidents.

High Learning Value Incidents
The formalized High Learning Value Incident (HLVI) is a process to capture and share key learnings and recommended actions from selected high profile incidents from within and outside Chevron. Business Units within Chevron review HLVIs for application in their organizations. If applicable, plans are developed and tracked to closure to address the HLVI recommended actions.

Corporate Major Incident Studies
Annually Chevron reviews and analyzes major incidents across Chevron and shares and issues reports. Line Management is responsible for reviewing the study findings within the organization. At the end of each annual major incident study, the assessment is made available to all employees for their review and learning.

Industry Associations and Networks
Chevron or our staff are members of or participate in numerous industry associations, forums, networks and conferences that share industry learnings, including incidents, with the objective of increasing industry safety and environmental performance.

Project Planning
Chevron believes that to achieve and sustain our objectives, we must develop a culture where everyone believes all accidents and operating disruptions are preventable and that "zero incidents" is possible. Within Chevron's OEMS, the following processes and expectations are included:

Hazard identification and risk evaluation;

Prior to commencing any project, Chevron requires that a Hazard Identification evaluation be conducted to determine significant risks of operations, possible threats to the environment and surroundings and to then determine the mitigation and control of the hazards before any work can commence. The process addresses risks from incidents (events), activities and ongoing practices and applies to all Chevron business units.

The Chevron drilling and completions Risk and Uncertainty Management Standard (RUMS) is a process designed to ensure that technical, operational, HES and financial risks and uncertainties are identified and appropriately mitigated. This Standard is specifically designed for risk and uncertainty management requirements related to Chevron well construction operations under Chevron Drilling and Completions (D&C) operational control.

The objectives of this Standard include:

- Systematically and explicitly identifying key uncertainties and associated risks for a given project/well.

- Defining a risk and uncertainty assessment process that will be useful for optimizing well design alternatives and effectively avoiding, mitigating and managing risks.
- Applying risk and uncertainty management during well execution to ensure that the Value Based Well Objectives (VBWO) are achieved.
- Establishment of a risk assessment process that can be used in conjunction with the Management of Change (MOC) process to determine the acceptable level of risk under which the well can proceed.

Chevron Hazard Identification Tool: To prevent incidents, workers must effectively identify the hazards associated with the tasks they perform. Based on the energy source concept, we ask workers to look for clues in the workplace which indicate one or more sources of energy may be present. Through education and training the worker develops the knowledge to identify potential hazards from the energy sources present.

Job safety analysis (JSA) and risk assessment: a requirement exists for tasks to be governed by JSA's and risk assessment appropriate to level of work to be performed. JSA's are used to identify job hazards and the respective mitigation, control or elimination of the hazards in order for work to proceed safely. If the worker and their supervisor determine that the hazard/s cannot be effectively managed, then work is not allowed to proceed and it must be reported immediately to the person in charge.

Design;

Chevron has in place a process where well incidents are shared globally within Chevron through our Communities of Practice (CoP) functional groups. If the incidents are of well design in nature, the learnings are incorporated into the design of future wells. As part of Chevron's well design process, called the single well Chevron Project Development and Execution Process (CPDEP), every well undergoes a phased gate review by the Peer Review Team, at which time well design will be one of the issues discussed in detail.

During each well operation, Chevron also conducts hole section reviews which capture best practices and lessons learned from each hole section drilled. At the end of well operation, a "Lookback" process is conducted by Chevron on the entire well drilling program following which information and lessons learned are shared globally within Chevron.

Equipment selection;

Chevron has a Global Drilling and Completions (D&C) Management Team. This Team works to issue Chevron D&C Global Standards which are used by each of Chevron's Strategic Business Units (SBUs) to develop SBU-specific Standard Operating Procedures (SOP). This group helps to manage standards and changes and modifications to standards used globally within Chevron.

Chevron D&C has in place a rig selection standard used globally by Chevron. Chevron also uses third party independent surveyors, consultants, inspectors and certifying bodies to ensure that drilling equipment to be used is certified, properly maintained and fit for use.

Development or modification of procedures and plans;

One of the 13 key elements in the Chevron OEMS is the topic of Management of Change (MOC), for which Chevron's Global D&C group utilizes a Subsurface MOC global standard. The Management of Change process addresses:

- Both permanent and temporary changes.
- Authority for approving changes.
- Evaluation of health and safety hazards, environmental impacts and mitigation.
- Communication of the change.

- Training of all personnel impacted by the changes to facilities, operations, products or the organization.
- Updates to and maintenance of critical documentation.

For additional discussion on Chevron's application of MOC, please refer to the responses provided for CFI 1.1.2(a-f), 1.1.4(f), 1.1.5(a-b), 1.6.1(a), 1.6.2(d), and 2.3.1(1i).

Selection and training of personnel;

The D&C community in Chevron has five main focus areas: People, Performance Improvement, Risk management, Category management and Business Leadership. The retention of trained, competent and experienced personnel is vital to success.

Chevron has an expectation that all workers in its Global D&C community will continually strive towards being the Clear Leader in the way we do our business. This includes both operational successes and delivering world class performance in health, safety and environment.

Chevron holds the fundamental belief that people are our most important asset and that the training and development of people will enable us to continue to grow and to improve. Chevron is always working to provide development opportunities and to creating a work environment that encourages challenge while building a global workforce team.

Past incidents, in particular the Ocean Ranger incident, have influenced requirements for Canadian safety related training when working offshore. A worker is required to take the following minimum training prior to going offshore:

- Basic Survival Training, or BST, which is a 5-day course for first time offshore workers. A refresher of BST is required every 3 years. Training in the use of Helicopter Underwater Emergency Breathing Apparatus (HUEBA) is completed during the BST.
- A personal Medical examination is a pre-requisite for the BST. The medical can take up to half a day to complete.
- Workplace Hazardous Materials Information System (WHMIS), is a 2-hour online course compulsory for all workers.
- H2S Alive is a 8-hour course also required for offshore oil and gas workers
- First Aid (Basic and Advanced) and CPR training can vary from 1 day to three days depending on the level required of the worker per job position.
- Regulatory Awareness training, which can vary from several hours to a full day of training, also depending on the workers job position.

Other Chevron and industry required training for offshore workers can be divided into three categorized as follows:

1. Personal Safety Training which provide individuals with a basic level of training to prepare them to react effectively to protect themselves and assist others in an emergency situation;
2. Technical Safety Training which ensure personnel assigned responsibility for the integrity and safe operation of the well and the installation are properly trained and competent in their area of responsibility;
3. Emergency Team Training which provide designated personnel with the knowledge and skills necessary to perform together as an effective emergency and rescue response team.

Further details can be found in the Canadian Association of Petroleum Producers (CAPP) Standard Practice for the Training and Qualifications of Personnel.

Projects in Operational Phase
Once operational, incidents and near misses are reported and investigated. Both Employees and contractors are required to recognize and report incidents and near misses.

Incidents and near misses requiring investigation are investigated at the probable level of consequence to identify root causes and appropriate preventive actions. Recommended actions are then assigned to the appropriate personnel, target dates for completion are set and the action items are tracked to closure.

Alerts and Bulletins: Depending on severity or possible outcome, or if there is potential for a similar incident to occur elsewhere, reports, alerts and bulletins are completed and shared. An Alert is issued prior to completing the incident investigation and is intended to share immediate information about an incident with other personnel, locations and facilities that may be vulnerable to the same threat or condition. A further Bulletin may also be issued after the incident investigation is complete and is intended to share incident investigation learnings based upon the root cause determination.

Call for Information No. 2

SCOPE ITEM #2 – IDENTIFICATION AND THE EFFECTIVENESS OF MEASURES TO PREVENT AND MITIGATE THE RISKS ASSOCIATED WITH ARCTIC OFFSHORE DRILLING, INCLUDING THE USE OF MANAGEMENT SYSTEMS

2.2.1 *Effectiveness of Management Systems*
Context: The effectiveness of measures employed to prevent and mitigate hazards and risks associated with offshore drilling activities will depend not only on equipment reliability, but also on the processes of ensuring that personnel are trained and competent to perform their duties. There should be a competency assurance system that considers key responsibilities and activities identified in major hazard risk assessments including the identification of safety and environmentally critical roles and tasks. Under section 5 of the current *Canada Oil and Gas Drilling and Production Regulations* (Drilling and Production Regulations), the applicant for an approval to drill a well is required to have an effective management system that includes:

- policies on which the system is based;
- processes for setting goals for the improvement of safety, environmental protection and waste management;
- processes for ensuring that personnel are trained and competent to perform their duties;
- processes for ensuring that all documents associated with the system are current, valid and have been approved by the appropriate level of authority;
- documents describing all management system processes and the processes for making personnel aware of their respective roles and responsibilities with respect to them;
- coordination of the management and operations of the proposed work or activity among the owner of the installation, the contractors, the operator and others, as applicable; and
- the name and position of the person accountable for the establishment and maintenance of the system and of the person responsible for implementing it.

As well, the operator must ensure compliance with the management system. A management system must address all possible well operations such as drilling, completion, recompletion, intervention, re-entry, workover, suspension and abandonment of a well.

Request:
a) Identify and describe all hazards that may be a threat to the safety and integrity of drilling operations and possibly impact the environment. Please list those hazards in order of severity.
b) Provide a list of the information needed to assess each hazard identified in a) and a determination of the adequacy of the knowledge base to support each of those assessments. Examples of potential hazards include ice features, working conditions and shallow gas zones.
c) What mitigation options could be used to reduce the volume of oil or gas released should there be loss of well control (e.g. designing slim hole, limiting tubing flow and use of expandable casing technology)?
d) The Canadian Association of Petroleum Producers (CAPP) has published a joint industry practice entitled "Atlantic Canada Offshore Petroleum Industry Standard Practice for the Training and Qualifications of Personnel." Please describe the areas where changes or improvements in the training and skills of personnel would be required for Arctic offshore drilling operations. Please identify any additional positions that may be required for Arctic operations. Please include a discussion related to the unique Arctic environment in light of the Gulf of Mexico BP Deepwater Horizon well incident and spill.

Responses to 2.2.1 (a) and 2.2.1 (b):

Please refer to Chevron's responses provided in Sections 1.5.1(a) and 1.5.1(b).

Response to 2.2.1 (c):

The primary design requirement of the wellbore and drilling systems is to safely retain fluids in a controlled condition thereby preventing blowouts. Minimizing flow for a blowout event is also a consideration in the well design process. Any wellbore configuration that limits the options for retaining or regaining control of a well during a kick or blowout would not be considered. Slimhole designs, smaller tubulars and other equipment would be evaluated in the well design if they fit the purpose without compromising well integrity or drilling operations.

Response to 2.2.1 (d):

Chevron supports the response provided by CAPP in this regard.

2.2.2 *Effectiveness of Operational Controls*

Context: Drilling offshore wells can be a hazardous activity as there are uncertainties about the predicted environmental load and effects and well conditions. Current technology relies on 'conventional' methods of monitoring well conditions. In the Arctic offshore, where operating conditions may be amongst the most difficult in the world and in areas where there is little or no infrastructure, it is important to look at diagnostic tools, warning systems, instrumentation and sensors, and other equipment designed to improve the safety of offshore drilling. Barriers include any fluid, plug or seal that prevents gas or oil or any other fluid from flowing unintentionally from a well or from one formation into another.

Request:

a) Describe the critical equipment required to maintain safety, integrity and environmental protection for Arctic well operations. How would critical equipment on a drilling unit be selected, tested, inspected, and maintained to ensure effectiveness and reliability;

b) Provide a fault tree analysis for each well barrier system including the blowout preventer, well casing and cementing, casing hanger seal assembly and drilling fluid density;

c) Describe possible blowout preventer (BOP) stack configurations, which would address conditions found in the unique Arctic environment. Please consider surface (above water) and subsea (below water) BOPs in your response. What evaluation criteria are used to determine the most appropriate (fit for purpose) configuration;

d) Provide a decision tree for an offshore relief well program; and

e) Describe emerging technologies and improvements in diagnostic tools, warning systems, instrumentation and sensors, and other equipment to improve the safety of Arctic offshore drilling in light of the Gulf of Mexico BP Deepwater Horizon well incident and spill.

Response to 2.2.2 (a):

Please refer to Chevron's responses provided in Section 1.4.1.

Response to 2.2.2 (b):

Chevron has a "Barrier Policy and Well Construction Philosophy Guide" in place as a standard operating procedure. The key elements of this document include a barrier policy, both mechanical and non-mechanical for all well construction phases from conductor casing through completion. This standard includes a barrier test and verification policy along with a definition of minimum barriers for floating rigs and various vessel operations that occur such as hurricane evacuation, a suspension of operations for icebergs or pack ice and a suspension of operations for a mechanical or hydraulic repair.

This guide describes a list of available mechanical barrier options and identifies those available, along with non-mechanical barriers, to be used for each phase of subsea well construction and during the completion phase, both with the blowout preventer stack on and off of the subsea wellhead.

Additionally, please refer to Chevron's responses provided in Section 1.6.1(a), (d) and (e); and Section 1.6.2(a), (c), and (d).

Response to 2.2.2 (c):

Chevron has a technical team dedicated to subsea BOP engineering. In light of Macondo, this team continues to assess potential enhancements to BOP designs, configurations, testing, certification, installation and maintenance procedures. Chevron is also jointly developing the AWKS, an enhanced BOP with potential application in the Arctic offshore (refer to *Chevron Canada Resources AODR Submission Part 1: Briefing Document)*. Subsea BOP stack configurations in the Arctic are subject to the same processes and evaluation criteria as used for other deepwater drilling locations.

Response to 2.2.2 (d):

Chevron has a “Recommended Practice for Relief Well Pre-Planning” document in place to be used as guidance in planning a relief well. Key items include:

- Guidance on identifying relief well locations based on a) environmental conditions; b) seabed obstacles & subsurface shallow hazard identification; c) positioning relief well locations to be conducive to surveying methods that minimize magnetic interference; d) well depth and target depths that might have to be intersected below the threshold depth; e) hazardous production such as hydrogen sulfide.
- Identification of assets to spud a relief well, such as riser and BOPs, should damage occur to the drilling vessel. Identification of an alternate drilling vessel for a relief well should the primary drilling unit suffer damage.
- Identification and location of back-up tangibles subsea wellheads and casing to initiate a relief well along with a timeline and logistics plan to transport other equipment to the remote location in support of the effort.
- Blowout modeling and Dynamic Kill planning that could infer an optimum solution such as the volume and types of fluids to be pumped and dynamic kill requirements involving horsepower requirements, fluid density and friction along with an evaluation of hydraulics engineering principles.
- Designing and acquiring any additional casing including non-magnetic joints; planning for the interception or kill point in the target well; designing the directional profile along with surveying methods to assure accuracy and defining the ranging strategy for electromagnetic tools to locate casing strings.

Please also refer to the discussion of Same Season Relief Well capability provided within the *Chevron Canada Resources AODR Submission Part 1: Briefing Document.*

Response to 2.2.2 (e):

The US Commission investigating the Macondo incident identified several instances where there were communication issues or missed warning signs within the available data. These breakdowns can be corrected through proper implementation of existing processes, including training and competency of the personnel. Chevron is always evaluating new technologies for inclusion in the design of monitoring systems, this is incorporated into our OE process of Asset Integrity. At the time of a drilling application, the well planning will consider new procedures and monitoring systems for well control.

Further discussion of emerging technologies and improvements in the predictive capabilities to improve the safety of Arctic offshore drilling has been provided within Sections 1.1.4 and 2.3.2.

2.2.3 *Abandoned Offshore Wells*

Context: All offshore oil and gas wells drilled to date in the Canadian Arctic have been abandoned. Effective abandonment procedures and practices result in containment in the long term without degradation of integrity.

Request:
a) Describe effective measures, practices and procedures conducted in the abandonment of an offshore well;
b) Describe the hazards and failures paths that the abandonment measures, practices and procedures are designed to mitigate;
c) Describe the possible degradation and failure mechanisms that could lead to flow, leakage or seepage between subsurface formations or to the surface; and
d) Comment on the degradation mechanisms that could occur and the predicted time to failure resulting in fluid flow from one formation to another or to the surface.

Responses to 2.2.3 (a), 2.2.3 (b), 2.2.2 (c) and 2.2.2 (d):

Chevron supports the responses provided by CAPP in this regard.

2.2.4 *Human Factors*

Context: Section 5(1) of the Drilling and Production Regulations states: The applicant for an authorization shall develop an effective management system that integrates operations and technical systems with the management of financial and human resources to ensure compliance with the [*Canadian Oil and Gas Operations Act* (COGOA)] and the Drilling and Production Regulations. Paragraph 5(2)(c) of the Drilling and Production Regulations requires that the management system include processes for identifying hazards and for evaluating and managing the associated risks. Drilling in the Arctic environment can pose unique challenges to worker performance as the demanding physical conditions have the potential to adversely affect workers' ability to perform as expected. These factors represent a potential threat to the overall safety of drilling operations. Worker performance is a combination of natural human abilities plus individual competency (aptitude and skill) in relation to demands of the task and the work environment. Performance may be negatively affected by physical stressors (including temperature, noise, vibration, confined space, continual daylight/darkness and fatigue) in the work environment. For the purposes of this request, human factors mean peoples' abilities, characteristics, and limitations relative to the application of what we know about people, their abilities, characteristics, and limitations relative to the design of equipment they use, environments in which they function, and jobs they perform.

Request:

a) Describe the human factors that must be considered within the context of the unique Arctic environment and associated drilling activities.

b) What factors have the potential to adversely affect worker performance (physical, physiological, and cognitive performance)?

c) Describe how these factors are addressed and mitigated during the project planning phase and during operation in order to effectively manage the potential for human error.

Responses to 2.2.4 (a), 2.2.4 (b) and 2.2.4 (c):

Chevron supports the responses provided by CAPP in this regard.

SCOPE ITEM #3 – STATE OF KNOWLEDGE OF THE ARCTIC OFFSHORE INCLUDING THE PHYSICAL ENVIRONMENT, BIOLOGICAL ENVIRONMENT AND GEOSCIENCES

2.3.1 *Unique Arctic Environment*

Context: Exploratory drilling in the Canadian Arctic offshore started in the early 1970s and the most recent drilling program was completed in 2006. Understanding of the environmental setting (physical, biological, and geosciences) is key in the planning, designing, implementing, operating, and completion of a drilling program in these areas. Environmental conditions may have an effect on human work factors and safety of operations. The Canadian Arctic offshore encompasses a wide range of physical conditions (meteorological, oceanographic, ice, etc.), a variety of diverse organisms and ecosystems (marine mammals, fish, intermediate species throughout the food chain, surface dwelling and pelagic species, etc.), and a range of soil and subsurface conditions (sea floor, target zones, surface stability, shelf slopes, shallow sub-surface hazards such as hydrates and permafrost, potential high-pressure zones, areas where there is a risk of loss of circulation, etc.). In the Gulf of Mexico BP Deepwater Horizon well accident and spill, well control measures reportedly failed (nature of the accident), and resulted in worker deaths and a significant oil spill for up to three months (magnitude of the accident). The Board is calling for the best available information that addresses the state of industry preparedness in the event of a similar scenario occurring in Canadian Arctic waters. Responses to this call for information should address unique environmental features in the Arctic that would be particularly sensitive to a major oil spill. Responders to this call for information should identify at least two geographic areas, one in the western Arctic and one in the eastern Arctic that would be of interest for future offshore oil and gas drilling. Based on offshore oil and gas rights issued by Indian and Northern Affairs Canada since 2007, the oil and gas industry's current interest is focused in the western Arctic in the Beaufort Sea, northwest of Tuktoyaktuk, Northwest Territories. The Exploration Licences issued are along the continental shelf with water depths ranging from about 100 m to over 1000 m. An example of an emerging area of interest in the eastern Arctic is the Davis Strait where two wells were recently drilled in Greenland Arctic waters, east of the Canada-Greenland international boundary. There have been no Exploration Licences issued by Indian and Northern Affairs Canada for the adjacent Canadian waters.

Request:
Consider a scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the western Arctic area during late summer. Consider a second scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the eastern Arctic area during late summer.

1. Based on the above scenarios for the western and eastern Arctic, with references to key supporting reports where appropriate:
a) Provide a description of the unique biological environmental features in the Arctic that would be particularly sensitive to a major oil spill;
b) Describe how the unique biological environmental features could affect the planned drilling activity, and what the potential effect of the planned operations would be on the environment;
c) Provide a description of the unique physical environmental features in the Arctic that would be particularly sensitive to a major oil spill including: polynyas, ice cover, sea state, shoreline features, and, bathymetric features;
d) Describe how the unique physical environmental features could potentially affect the planned drilling activity, and what the effect of the planned activity would have on the environment;
e) Describe any gaps in the state of knowledge in terms of the environmental setting (biological, physical and geological) and how these gaps would be addressed prior to submission, review, and decision making on any application for proposed drilling activity;
f) Describe the process for eliminating the gaps identified in e) to ensure an operation would be safe and protects the environment. Include discussion of on-going research or information gathering initiatives and how this information would be coordinated;
g) Describe the state of knowledge in the determination of the design criteria and means for keeping current with emerging information;

h) Discuss the current state of knowledge that is available for the above scenarios addressing unique environmental and geological features that would be relevant in the design conditions of a drilling system or program. Information should include, but not be limited to:

- **designing the drilling rig, equipment and working conditions for anticipated Arctic physical, biological and geological environments;**
- **drilling operations;**
- **well completions; and**
- **well termination.**

i) Describe the contingency measures if physical, environmental or geological conditions were to exceed the design or operating limits; and

j) Discuss the current state of knowledge that is available for the above scenarios including unique surface features in the Arctic that would be particularly sensitive to an oil spill.

2. For each response to Request 1, please indicate whether the response would change if the scenarios were to occur at another time of year. If there is a change, please provide the details.

Response to 2.3.1 (1a):

Chevron supports the response provided by CAPP in this regard.

Response to 2.3.1 (1b):

Any proposed Arctic drilling project would be required by federal legislation to complete an environmental assessment (EA); and this EA would also meet the Operating Guidelines and Procedures of the Inuvialuit *Environmental Impact Screening and Review Process.* Two general types of effects are considered within an EA, including:

- Effects of the environment on the Project; and
- Effects of the Project on the environment, particularly the biological environment.

Unique biological environmental features would be identified through the potential data sources described in Section 2.3.1(1a) of the CAPP submission, including the Beaufort Sea Environmental Sensitivity Atlas, Inuvialuit Community Conservation Plans, academic resources, and government resources.

Response to 2.3.1 (1c):

Any proposed Arctic offshore drilling program would be required by federal legislation to complete an Environmental Assessment, which would consider factors such as timing, location, scope of the activity, mitigation measures, and effects of a potential spill. For an overview of some of the main information sources that would be considered in the context of evaluating potential spill sensitivity on physical environmental features from a specific project in a specific location, please refer to the response provided for Section 2.3.1(1a) within the CAPP submission.

Response to 2.3.1 (1d):

Any proposed Arctic drilling project would be required by federal legislation to complete an environmental assessment (EA); and this EA would also meet the Operating Guidelines and Procedures of the Inuvialuit *Environmental Impact Screening and Review Process.* Two general types of effects are considered within an EA, including:

- Effects of the environment on the Project; and
- Effects of the Project on the environment.

Unique physical environmental features would be identified through the potential data sources described in Section 2.3.1(1a) of the CAPP submission, including the Beaufort Sea Environmental Sensitivity Atlas, Inuvialuit Community Conservation Plans, academic resources, industry resources and government resources.

Response to 2.3.1 (1e) and 2.3.1 (1f):

Chevron supports the responses provided by CAPP in this regard.

Response to 2.3.1 (1g):

Chevron Corporation is a multi-national energy company with distributed resources worldwide. We have a number of departments and personnel within the corporation tasked with developing, monitoring and sharing emerging technologies with our business units throughout the company including the Chevron Energy Technology Company. Chevron also regularly applies a technology planning process and project peer reviews to the life of the project to ensure any emerging knowledge, information or technologies that may be applicable to a project are considered. All disciplines within the company also maintain various Communities of Practice held on a regular basis with attendance from each global business unit where sharing of knowledge and best practices is a key purpose.

Chevron also participates in several Research & Technology initiatives, both independently and in conjunction with academia, government, and other industry participants in both developing and validating state of knowledge.

Chevron also maintains industry affiliations through agencies such as the Canadian Association of Petroleum Producers, the American Petroleum Institute, and various technical societies, which provide an external opportunity for industry-wide sharing of emerging information.

Response to 2.3.1 (1h):

Some of the key factors that will impact the design of an appropriate drilling system and the associated drilling program include:

- Ice Conditions
- Station-Keeping System
- Subsurface Information
- Infrastructure / Logistics

The manner by which each of these areas impacts on the drill system design and operation is outlined as follows, along with a summary of the current state of knowledge in each of these areas. As addressed in the *Chevron Canada Resources AODR Submission Part 1: Briefing Document*, this discussion reflects floating, exploration drilling operations in the Canadian Beaufort Sea.

Ice Conditions – Ice conditions are a key design parameter and will have a direct impact on the following areas:

- Ice Class of drillship and marine support
- Need for BOP / Sub-sea equipment protection from ice scour
- Design of the station-keeping system whether moored or dynamically positioned
- Design of a quick-disconnect system in the event of an emergency move-off

- The possible need for a spare BOP stack in the event that the main BOP stack is left on the seafloor and cannot be retrieved due to ice cover restrictions
- Design of Emergency Escape and Evacuation (EER) equipment and procedures
- Selection of suitable well intervention system i.e. relief well vs well capping BOP or similar pre-engineered solution
- Selection of appropriate oilspill containment and clean-up systems

Both current and historical ice data in Canada via the Canadian Ice Service are accurate and reliable sources of current information. Information on ice type, concentration and distribution are available daily during the operating season. Historical drilling activities and their station-keeping efficiencies can be compared against the prevalent historical ice conditions thus providing a means of predicting operational efficiency in new and emerging parts of the basin. The Chevron Arctic Center has developed a Tactical Ice Management System (TIMS) system that allows the following parameters to be simulated prior to undertaking an exploration drilling operation in the field:

- The number and ice class of the ice management vessels
- Percentage of old vs. first year ice
- Ice drift direction and speed
- Number and frequency of ice ridges
- Impact of “pressured ice”
- Impact of darkness on ice management efficiency

By utilizing the TIMS system coupled with the extensive database of Canadian Beaufort Sea ice conditions, dating back to the late 1970’s, Chevron is confident that the existing state of knowledge is more than adequate to allow it to operate safely in the Canadian Beaufort.

Station-Keeping System – Water depth largely impacts on the cross-over point where one would move from a moored to a dynamically positioned (DP) drilling system. There are a number of factors that are taken into account when making this decision, namely:

- Wind and wave conditions - moored drilling systems have historically been used in shallow water (down to 100m) in areas where there is a benign wind and wave climate.
- The presence and extent of pack ice conditions – In a pack ice operating environment there is tendency to consider deeper water depths when operating in DP mode thus allowing a safety margin in the case of an emergency disconnect.
- Fast disconnect system – the ability to carry out a rapid disconnect provides a greater safety margin when operating in a shallow water, pack ice environment, whether moored or DP.
- The practical limit for a moored system – while mooring systems can be deployed in very deep water they often require specialized equipment that is often only found in mature operating areas. With that in mind, the mooring system limit may be a factor of what can be easily deployed via the selected ice management equipment.

In terms of wind, wave, and bathymetric information Chevron believes that the current state of knowledge is suitable to design a safe and efficient station-keeping system.

Subsurface Information – Various forms of sub-surface information will be required to complete the design of the drilling program. Most of this information is derived via the seismic and from other prior drilling programs in the basin, and includes:

- Permafrost – The presence and extent of permafrost impact on the design of the both the casing, cementing and drilling fluids programs. Permafrost has been extensively mapped in the Canadian Beaufort and detailed maps are available.
- Shallow Gas – Shallow gas hazards can be detected via dedicated shallow geohazard surveys of through the use of processed 3-D seismic. These techniques are well established and proven.
- Pore Pressure – Similarly, pore pressure estimates can be developed through the use of processed 3D seismic data and offset well data, and provide a good indication of the pore pressure trend and magnitude.
- Geology – Seismic and regional geological models provide an understanding of the subsurface. In conjunction with the pore pressure data, they provide information on appropriate casing setting depths.

With 39 wells having been successfully drilled from floating drilling systems in the Canadian Beaufort Sea, industry's ability to properly assess these hazards and design appropriate drilling programs has been established. On this basis, Chevron believes that the state of knowledge in this area is more than adequate to allow safe drilling operations to be conducted in the Canadian Beaufort Sea.

Infrastructure / Logistics – Given the summary provided in Section 1.5.1(g), logistical constraints influence the size and design of the drillship and marine support fleet especially if late season (after October 1) operations are planned.

Two differences between drilling in the Arctic and conventional offshore basins elsewhere in the world are logistics and station-keeping. Both of these issues are well understood by industry from previous drilling programs, and form a key aspect of a comprehensive drilling system design. As such, Chevron believes the current state of knowledge in area of logistics and infrastructure is suitable to allow safe drilling operations to be conducted in the Canadian Beaufort Sea.

Response to 2.3.1 (1i):

Contingency planning is a component of both the project planning and the regulatory process, and appropriate contingency plans would be prepared in support of a Beaufort Sea drilling application. Any temporary or permanent conditions that exceeded the design or operating limits would also be addressed by the Management of Change process, including authority for approving any changes; evaluation of health and safety hazards, environmental impacts and mitigation; communication of the change; required training of all personnel impacted by the changes; and updates to critical documentation and procedures.

Chevron also addresses these principles through the following two of our 10 Tenets of Operations to ensure they are addressed within the project planning process (refer to Section 1.1.3(b):

Tenet 1 – Always operate within design and environmental limits; and
Tenet 8 – Always address abnormal conditions.

Response to 2.3.1 (1j):

Any proposed Arctic offshore drilling program would be subject to the federal environmental assessment process, which would consider factors such as timing, location, scope of the activity, mitigation measures, and effects of a potential spill. For an overview of some of the main information sources that would be considered in the context of evaluating potential spill sensitivity on unique surface features from a specific project in a specific location, please refer to the response provided for Section 2.3.1(1a) within the CAPP submission. For the current state of knowledge in terms of the environmental setting, including physical surface features, please refer to Section 2.3.1(1e) of the CAPP response.

Responses to 2.3.1 (2a-j):

Any proposed Arctic offshore drilling program would be subject to the federal environmental assessment (EA) process, which includes the timing of that proposed program as a key element. The temporal boundaries established within the EA for any given proposed project would be applied to the assessment components discussed within Section 2.3.1(1a-j).

2.3.2 *Geo-hazards*

Context: It is imperative in oil and gas operations to identify and manage geo-hazards. Pressure is a key component in the performance of a conventional hydrocarbon reservoir. Accurate pore pressure determination ahead of the drill bit is one way of detecting unexpected increased pore pressure which may result in a blowout.

Request:
Understanding geosciences is key in the planning, designing, implementing, operating, and completion of a drilling program in the Canadian Arctic offshore. Please discuss:
a) The methods that are available to reliably predict formation pressure before and during drilling, especially as they relate to exploration drilling hazards including high pore pressure;
b) How to identify and mitigate for shallow hazards including shallow water flow sands, shallow gas, hydrates, permafrost, active faulting and weak formations;
c) How to identify and effectively deal with natural and man-made hazards including seabed collapse, slope stability and well completions;
d) The emerging techniques to predict formation pressure ahead of the drill bit;
e) The effects of formation pressure regimes on the well design; and
f) How knowing pressures in the formations would affect the operation of a well?

Response to 2.3.2 (a):

If compaction disequilibrium is the primary mechanism for generating subsurface pressure, seismic velocity analysis, in conjunction with a regional geologic understanding, can be used during well planning to estimate shallow overpressure and identify zones which may present a risk for shallow water and/or gas flow. Additionally, information about anticipated stratigraphy, lithology, structure and reservoir fluid can help us to estimate reservoir pressures. During well execution, real-time log-based pore pressure analysis is performed at the rig site and in the office. All available information is incorporated into the real-time pressure analysis: pressure measurements, logging while drilling curves (sonic and resistivity), information about cuttings and gas, and drilling parameters. Please also refer to the response provided in Section 2.3.1(1h).

Response to 2.3.2 (b):

Deep water exploration drilling with a dynamically positioned Mobile Offshore Drilling Unit (MODU) has only one point of contact with sea-bed, which is the well head. As such, these programs typically use conventional 3D marine streamer seismic, reprocessed to near-offset-time migrated stack for increased frequency and resolution, to better image the near mudline geology. With such data we are able to assess drilling risks in the shallow hole sections prior to placing pressure control systems in use, including riser, BOP, and mud column to surface.

The identification of shallow hazards with near offset seismic is based on mapping for amplitude anomalies distributed around the well bore along with seismic facies and lithology interpretation to discern the geologic conditions in order to anticipate any potential for drilling events. The seismic amplitude anomaly maps can help to assess risk of shallow gas, water, and the possibility of gas hydrates. Structure, stratigraphic, lithologic changes, and faulting are commonly imaged by these amplitude anomaly maps. Seismic facies and lithology interpretations can help assess the risk of well bore instability along with the potential for assessing the risk of shallow water flow sands. These 3D marine streamer high resolution seismic data sets are quite successful in imaging relatively small features typically on the order of 5 to 6 meters vertically and 10 to 25 meters laterally. At this level of seismic resolution, small displacement faulting and stratigraphic changes are well imaged for assessing the potential risk to drilling at a specific location.

Mitigation is most effective prior to spud with a thorough risk assessment. Avoidance is the most effective tool for shallow hazard mitigation. Proper well placement to avoid documented shallow hazards will reduce their risk by removing them from the near wellbore area affected by drilling. A standard pre-spud operation is to sight-in the spud location at the sea floor with a ROV to make final assurances nothing unexpected has occupied the drill location. This is also done to confirm the actual water depth to remove any uncertainty due to inaccuracies of the measured water column velocity.

Response to 2.3.2 (c):

Geo-hazard surveys, using geophysical and geotechnical methods, are routinely conducted at sites of proposed exploratory wells. Final survey reports are submitted prior to an Application to Drill a Well at the well location. Guidelines for conducting surveys are provided by the regulator. For example, the most recent CNLOPB guidelines are contained in section 7.0 of the 'Geophysical, Geological, Environmental and Geotechnical Program Guidelines, February 2011'.

The objective of the survey is to:

- Identify shallow geologic hazards (i.e. slumping, channels, faulting, gas, gas hydrates, shallow trap closures and permafrost)
- Define the surficial geology including the nature and characteristics of the seafloor sediments and the bathymetric details~~.~~
- Identify iceberg scours, morphology of depositional units, seafloor obstructions, and bedforms indicative of seafloor sediment dynamics.

Typical methodologies include high resolution 2-D multi-channel seismic systems in conjunction with sub-bottom profiling, side scan sonar and/or multibeam systems. Reprocessed 3-D seismic may replace a conventional 2-D dataset. Cores of the seafloor and near surface sediments are collected when appropriate.

The primary mitigation method is to relocate the mudline well location. However some potential hazards may be mitigated by appropriate design of the drilling program.

Response to 2.3.2 (d):

Borehole seismic is being promoted as an enhanced technology for the purpose of predicting formation pressure ahead of the bit. Chevron is in contact with service providers to understand and evaluate any technology developments that can improve hazard identification. At the time of a Drilling Application, Chevron will evaluate the merits of any system able to predict formations pressures ahead of the bit.

Response to 2.3.2 (e):

Pore pressure and fracture gradient impact many aspects of the well design, but most notably the mud and casing programs. The depth and magnitude of pressure ramps influence casing/liner setting depths and selection decisions for tubulars, hangers, and subsea equipment. Uncertainty in the pressure regime may also influence the formation evaluation plan for the well.

Response to 2.3.2 (f):

A strong understanding of formation pressure during drilling operations improves our ability to drill wells safely. Real-time updates to the pressure model, using logs, drilling parameters, and cuttings, will influence decisions about drilling mud weight and casing setting depths.

SCOPE ITEM #7 – THE EFFECTIVENESS AND AVAILABILITY OF SPILL CONTAINMENT AND CLEAN-UP OPTIONS UNDER ARCTIC CONDITIONS, INCLUDING TRACKING METHODS, RECOVERY TECHNOLOGIES, PROCEDURES, EQUIPMENT AND TRAINED PERSONNEL

2.7.1 *Effectiveness of Available Spill Containment and Clean Up Options*

Context: The Board is calling for submission of the best available information on current and emerging technologies that could be used to effectively contain and clean-up an oil spill in the unique Arctic environment in the event that something similar to the Gulf of Mexico BP Deepwater Horizon well accident and spill of 2010 were to occur in Canadian Arctic waters. The Board would also like to identify the existing inventory of Arctic incident response equipment. Each applicant for an approval to drill a well in the Arctic offshore is required to have an effective management system (Section 5 of the Drilling and Production Regulations), and to submit a safety plan including emergency response procedures (subsection 6(j) of the Drilling and Production Regulations). Subsection 6(j) also requires each applicant to, "provide for coordination measures with any relevant municipal, provincial, territorial or federal emergency response plan", and to "identify the scope and frequency of the field practice exercise of oil spill countermeasures." Based on offshore oil and gas rights issued by Indian and Northern Affairs Canada since 2007, the oil and gas industry's current interest is focused in the western Arctic in the Beaufort Sea, northwest of Tuktoyaktuk, Northwest Territories. The Exploration Licences issued are along the continental shelf with water depths ranging from about 100 m to over 1000 m. An emerging area of interest is in the eastern Arctic in Davis Strait where two wells were recently drilled in Greenland Arctic waters, east of the Canada-Greenland international boundary. There have been no Exploration Licences issued by Indian and Northern Affairs Canada for the adjacent Canadian waters.

Request:

Consider a scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the western Arctic during late summer. Consider a second scenario of the nature and magnitude of the Gulf of Mexico BP Deepwater Horizon well accident and spill and transpose it to the eastern Arctic during late summer. Please provide a description of, and where appropriate, identify peer-reviewed supporting documentation for:

a) The types of currently available equipment and approaches or options that could be applied in the Arctic, their performance under Arctic conditions and their likely effectiveness for containing and cleaning-up contaminants from an oil or gas release. This should include, but not be limited to, physical containment equipment and methodologies (e.g. booms and boom deployment equipment), recovery equipment and methodologies (e.g. skimmers and temporary storage) as well as chemical responses and application methodologies (e.g. dispersants or surfactants);

b) The availability (quantities, locations and response times) of the resources described in a) adequate for the Arctic scenarios previously identified and the workforce required to carry out the drilling and to respond to a spill of the magnitude of the Gulf of Mexico BP Deepwater Horizon well accident;

c) Descriptions of all emerging containment and cleanup options or technologies which could be feasibly available and applicable in the short- (1 – 5 years) and medium-terms (5 – 10 years). Also include a discussion of the readiness for application of the technologies. This discussion should include, but not be limited to:

- **successful full-scale field trials under actual Arctic conditions;**
- **prototype technology demonstrations under Arctic conditions; and**
- **prototype technology demonstrations at laboratory bench-scales that might be developed and available if Arctic offshore drilling occurs.**

d) The key differences in working conditions between the Arctic environment and the Gulf of Mexico environment for a major oil spill response;

e) How the key differences identified in d) would affect response personnel physically (e.g., in deploying or operating the spill containment and cleanup equipment or technologies) and psychologically (e.g., as a consequence of isolation, increased or reduced ambient light, and cold working conditions);

f) The capacity and state of preparedness of territorial or federal government agencies, including the Canadian Coast Guard and Environment Canada to assist with the containment and cleanup approaches or options identified in a); and

g) The capacity and state of preparedness of northern communities to assist with the containment and cleanup approaches or options identified in a).

Response to 2.7.1 (a):

This response has been provided as part of Section 1.5.1 (e) as indicated.

Response to 2.7.1 (b):

This response has been provided as part of Section 1.5.1 (f) as indicated.

Response to 2.7.1 (c):

As outlined within the responses provided within Section 1.5.1 and 2.7.1, there is an extensive background of experience with a combination of lab/bench-scale testing, tank and basin testing, field experimental spills at scales from a few cubic meters to 50+ cubic meters where all of the available Arctic countermeasures techniques have been successfully evaluated, measured and implemented operationally (Dickins, 2011). There is no new “emerging” containment and clean-up option specific to the Arctic that has not been already applied at a large scale elsewhere or in previous experimental spills. The applicability and efficacy of mechanical recovery systems and in situ burning under different oil and ice scenarios have been evaluated in numerous studies and research projects over the past 35 years. Dispersants while used worldwide on numerous occasions in response to large spills at sea have only recently (past 5 years) been considered seriously as a potentially “new” Arctic countermeasure with applicability to spills in and among ice. SL Ross et al., (2010) provide a comprehensive review of the current state of knowledge in all of these area and advances over the past 20 years (since 1990).

In situ burning of oil contained within fire resistant booms is well documented in both arctic and conventional environments. The most recent experience involved successfully burning oil among small ice pieces, cakes and brash collected within two different fire booms in the Norwegian Barents Sea in 2009 (Potter et al., 2010). Uncontained burning of oil spilled in openings within an ice cover and subsequently thickened by applying a non-toxic herding agent was proven in field trials in Norway in 2009 after extensive lab and tank testing (Buist et al., 2010). Burning oil on melt pools in the spring after the oil has been trapped within the ice through a winter was tested successfully in several large scale experiments carried out in the Canadian Beaufort Sea in 1975 and 1980 and Svalbard in 2006 (Norcor 1975, Dickins and Buist 1981, Dickins et al., 2008).
Recent interest in improving the technology for aerial ignition of oil has led to the proof of concept tests that could lead to a gelled delivery system capable of being operated from a fixed wing aircraft and operated at higher flight speeds than the existing helicopter-slung Helitorch (Preli et al., 2011). Full Transport Canada (and FAA) certification would be required before any such new aerial ignition systems become operational.

Aerial and ship-based dispersant application to surface slicks is a proven technology with little further development needed for open water operations. For Arctic applications in the presence of ice, newer formulations of dispersants as a gel product could increase the window of applicability for spills in ice, for example spraying oil that rises to the surface of the ice in the spring instead of igniting it. At this stage, this concept is still developmental but may be proven in the short term (Nedwed et al., 2008). The use of vessel propellers or thrusters to add artificial mixing energy while adding chemical dispersants at the same time to oil among high concentrations of ice was proven recently in tank tests and at sea (Nedwed et al., 2007; Daling et al., 2010). Subsea injection of dispersant is not a new idea, but following the successful implementation during the Macondo incident has captured the attention of responders as being a potentially effective strategy especially relevant to large deep water blowouts. More work needs to be done to understand the process, the likely effectiveness, long term impacts and systems to deliver the dispersant quickly and reliably. A number of industry sponsored research studies are ongoing or in the planning stages to further the development of this tool as a key oil spill response (OSR) countermeasure for both temperate and Arctic regions.

Chevron continues to support major industry initiatives aimed at advancing strategies for Arctic spill response, for example in joint industry projects. Chevron was a sponsor in the SINTEF Oil in Ice JIP over the past four years (2007-10). That series of projects represents the largest and most comprehensive research program of its kind, focused specifically on issues of responding to spills in ice (Sorstrom et al., 2010).

Responses to 2.7.1 (d) and 2.7.1. (e):

The response to 2.7.1 (d) and (e) has been provided as part of Section 1.5.1 (h) as indicated.

Response to 2.7.1 (f):

The response strategies proposed by Chevron as the basis for worst-case contingency planning depend on having the initial key resources (marine equipment and supplies) nearby and ready to deploy once the safety of the rig crew and well integrity is ensured. Any Federal Government resources in the area at the time would be called on to assist as needed.

Response to 2.7.1 (g):

See above discussion regarding local training that would be incorporated part of any OSRP developed prior to permitting any new well (CFI 1.5.1 (q)). Existing community infrastructure is described in brief under CFI 1.5.1 (g). During previous periods of extensive offshore exploration in the Beaufort area, a Spill Response Co-operative was established to combine company resources and expertise as well as to maintain a trained core group of local residents in spill response. Whether a similar model or something different is most effective today would depend on how future development proceeds (multiple wells or single company programs in any given year) and the drilling locations determining the potential for any shoreline impacts.