Paper #2-10

OFFSHORE PRODUCTION FACILITIES AND PIPELINES, INCLUDING ARCTIC PLATFORM DESIGNS

Prepared by the Offshore Operations Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Table of Contents

EXECUTIVE SUMMARY

Production platforms and subsea pipelines are essential requirements for recovery of hydrocarbon resources from offshore environments. They also account for the two most significant categories of physical footprints of oil and gas developments in marine environments. As more oil and gas developments have moved progressively into deepwater sites, and farther from shore, leading-edge technological developments have emphasized increased ruggedness and reliability of subsea equipment and construction methods as the most dependable approaches to reducing the physical footprints, and therefore the environmental impacts, of offshore oil and gas production.

Environmental aspects of platform operations include management of wastewater as well as air emissions. Pipeline operations emphasize leak avoidance through continuous monitoring and remote control along with regular inspection and maintenance. Focal points for further progress include:

- Continuous improvement of equipment and techniques for subsea flow-assurance and separation. The largest, value-added advancements are needed to lengthen the working lifetimes and reduce the maintenance intensity for subsea systems.

- Wastewater handling on offshore platforms according to require site-specific choices among multiple, permitted alternatives; no single waste-disposal approach will be optimum for all situations.

- Offshore wastewater treatment and disposal through ongoing improvements in several different physical and chemical technologies while also pursuing methods to reduce overall volumes of wastewater generated.

- Management of air emissions from offshore platforms by reducing the need for venting and flaring through capture, subsurface re-injection or other alternatives.

- Increase public awareness, and industry attentiveness, to pipeline locations so that damages to pipelines can be avoided and environmental threats from leaks thereby reduced.

Air emissions from offshore production facilities include several different combustion, venting, and flaring sources. Those sources have been found to not significantly affect coastal areas but should continue to be monitored to ensure that the favorable non-impact finding does not change. BOEMRE has a good system of permitting air emissions from offshore platforms that is protective of onshore air quality and has made significant progress in reducing natural gas (methane) venting emissions.

Pipelines have proven to be the safest, most reliable, economical and environmentally favorable way to transport oil and gas throughout the US, including offshore developments The aging of the pipeline infrastructure suggests that continual improvement in system integrity, monitoring, and leak-detection is necessary.

INTRODUCTION

A. Offshore Production Facilities

The development of offshore oil and gas reserves requires the construction and installation of facilities to produce and process the oil and gas. The purpose of production facilities is to provide for the necessary separation of oil from natural gas and water – all of which commonly flow upward as raw petroleum through the same wellbore – plus suitable direction of the separated streams to other gathering or storage systems. Historically, this has required the installation of numerous platforms on structures fixed to the seafloor and located in the immediate proximity of the target reserves. Over the past one to two decades, technologies have been developed that reduce the number facilities required and thus reduce the physical footprints of oil and gas facilities. Several of those technologies can play major roles in reducing the environmental impact of oil and gas production.

B. Offshore Pipelines

Pipelines are the safest, most reliable and economical method to transport oil and gas from offshore waters around the United States. There are approximately 33,000 miles of liquid and gas pipelines in the US Outer Continental Shelf (OCS) and many more miles in shallow, offshore waters and coastal areas.

Pipeline operators spend millions of dollars annually to design, construct, operate and maintain their assets and comply with Federal and State laws and regulations. Pipeline operators continually seek to reduce the risk of accidental releases by taking measures to minimize the probability and severity of incidents. Key measures include proper route selection, design, construction, operation, maintenance and inspection.

C. Arctic Adaptations

Although oil and gas offshore operations within Arctic regions often are treated as a separate subject, in fact, the same basic objectives apply as for non-Arctic regions. Platforms and pipelines around the world are designed to resist location-specific environmental forces, ranging from hurricane winds, waves, currents, tides, mudslides, earthquakes and ice. Differences in Arctic regions mostly reflect special, ice-related environmental adaptations needed for technologies and procedures applied to construction and operation as well as some modifications to permitting processes.

ORRAP (2010) stated that it “was impressed by a presentation from the oil extraction industry in Alaska regarding its ocean, coastal and ice observing capabilities and investments” and further commented that the industry-developed knowledge and capabilities, although driven by NEPA-EIS requirements, offers wider and longer-term benefits to Arctic knowledge. Therefore, baseline environmental knowledge required to design, build and operate offshore structures in the Arctic already is recognized by authorities on the Arctic environment.

PHYSICAL FOOTPRINTS OF PRODUCTION FACILITIES

A. Overview of Footprint-Reducing Technologies

Three main technologies have been developed to reduce the amount and surface extent of the infrastructures needed to produce subsea hydrocarbon resources. First, extended-reach and horizontal drilling means that, from an individual vertical borehole, more oil and gas reserves can be reached using lateral boreholes developed from each vertical borehole. By connecting multiple reservoirs through a lesser number of vertical boreholes, more hydrocarbons can be gathering with fewer production facilities. Second, unmanned satellite production systems, which contain wellhead and manifold systems with no or only minimal processing facilities, are utilized to develop smaller fields or sections of larger fields. The production from those satellite facilities flows to a central facility where the produced fluids are processed. Satellite facilities can either be installed on small platform structures or on the seafloor. This satellite/central facility concept eliminates the need for multiple, larger production facilities. Third, floating production systems typically are used in deep water and in conjunction with subsea production or satellite systems. Since fixed structures are not utilized, these systems have the added advantage of being easily removed at the end of the field development.

Additional focus has been placed on technologies to assure long-distance flow of raw petroleum streams and to separate the raw streams into separate sub-streams. Details of those technologies are viewed in the following paragraphs.

B. Subsea and Flow Assurance Technologies

Advances in subsea technologies in recent years have allowed the full wellstream production from subsea wells to be transported longer distances to processing facilities, thus optimizing the number and location of offshore surface facilities. It is essential for subsea technologies to be highly reliable, due to the high cost of intervention. These technologies continue to improve, and they include the following:

- Piping and piping components, including thermal insulation, designed for seawater environment, and rated to withstand the high external pressures associated with deep water.
- Process controls and power/electrical systems (including umbilicals) designed for subsea environment and long distances from host facilities.
- Subsea processing equipment such as multiphase pumps, which allow full wellstream fluids to be transported long distances by boosting their pressure. Other subsea processing equipment includes multiphase meters, subsea separators and water injection pumps. These technologies enable the development and tie-back of reservoirs long distances from existing facilities thus eliminating the need for new platforms.
- Remote-operated-vehicles (ROVs) and other methods for subsea intervention.

- Technologies to manage flow assurance issues related to long-distance transportation of multiphase fluids in a subsea environment, including: chemicals such as hydrate and wax inhibitors and drag reducing agents, pipeline insulation and heating systems, slug suppression systems, and improved modeling capabilities of transient phenomena (shutdowns and restarts).

C. Subsea Separation Technologies

The development of subsea processing and separation technologies is primarily driven by the need to develop smaller, more compact equipment with higher efficiencies for deepwater developments. Shifting from designs using gravity-based separation to designs that use principles such as high G-forces, pipe-separation technologies, and electrostatic coalescence are examples of technologies that may enable the design of compact separators. Additionally, these technologies reduce the size and number of facilities required to develop oil and gas reserves, can result in a significant reduction in the quantities of produced water brought to the surface for processing and management, and can facilitate extending the economic life of oil and gas developments.

Subsea processing provides opportunities to achieve more effective development of oil reservoirs around the world. Produced-water separation and re-injection is one of the first subsea processing concepts applied. In Norway both the Troll C Pilot and the Tordis projects have applied this approach, which resulted in both increased production and improved hydrocarbon recovery. Additionally, this approach eliminates a need to increase produced-water handling capacity on a host facility. Retrofits of increased capacity on existing facilities are often highly expensive or impractical due to space constraints.

The Tordis Subsea Separation and Boosting and Injection system was installed and started up in 2007. This version of the technology was designed to boost the hydrocarbon stream pressure and perform water separation and disposal. The processing facilities have proven to work in accordance with design and generally have exceeded expectations. However, operating problems outside the processing station in the injection well have limited the use of the station.

The industry continues to develop more efficient separation technology to enable the cost-effective use of subsea separation. Many of these technologies are being developed for topside facilities applications and can be extended to use in the subsea applications. Inline separation technology that induces swirl flow has the potential to achieve high separation efficiency in a very compact design. Variations in the technology and design include the capability to handle sand, gas-liquid and liquid-liquid separation. A common feature is that phase separation is achieved in a pipe spool with a similar diameter as the piping upstream and downstream the separator, with a total length of approximately 5 to 10 pipe diameters.

There is an increasing need for efficient, compact separation solutions for subsea applications. Separator technologies will continue to evolve in terms of providing increased system efficiency and maintainability while becoming more compact and meeting the requirements of relevant design standards. Separation technology will likely rely on advanced concepts such as high G-force separation, electrostatic forces and multiple low diameter units. This will increase functionality while optimizing system costs and design configuration (Vu et al., 2009).

WASTE HANDLING ON OFFSHORE FACILITIES

A. Produced Water

Produced water is the largest volume by-product associated with oil and gas production. In the United States alone, 15-20 billion barrels are produced each year with around 1 billion coming from offshore operations, while worldwide 77 billion barrels are produced. The amount of produced water from an active well typically increases as the well ages while oil and gas production steadily declines. In the United States, a very mature region, Argonne National Laboratory estimates that seven barrels of water are produced for each barrel of oil, with some very mature wells having a ratio of 50:1. Worldwide the estimate ranges from 2:1 to 3:1 (Veil et al., 2004; Veil, 2009).

There are numerous strategies and technologies to minimize the environmental impact of produced water in practice today. The first strategy is to implement production practices that prevent the water from leaving its place in the reservoir (rock formation) to enter the wellbore and ascend to the surface. The second strategy is to separate then re-inject the produced water back into the subsurface. The vast majority of water produced in association with onshore operations is managed through re-injection although that practice is much less common offshore. In offshore operations, most produced water is treated to reduce oil and grease content to levels that are below recognized levels of environmental concern and then discharged to the sea.

<u>Produced Water Volume Reduction</u>. Operational, mechanical or chemical means can be used to reduce the water volume entering the wellbore from the formation. The most common operational, proactive means for controlling water production is to shut-in wells with high water production volumes. Mechanical means of isolation can be used to physically block sections of producing formations that are producing excessive water volumes while allowing those sections that produce more oil to continue producing. Examples of mechanical sealing devices include mechanical or inflatable packers or plugs, cementing, or casing or tubing patches.

Injection of inorganic or polymer gels is the most common method of chemical downhole water shut-off. Gels are sometimes placed in wells via coiled tubing or sometimes may require use of workover rigs. The gels work by permeating through the formation rock, creating a plug or seal that blocks the flow of water. Advantages of using gels over mechanical means of isolation include the fact that the entire wellbore diameter is still available for any repairs and that the gel can penetrate deeply into the formation rock, preventing water from flowing behind the tubing. A disadvantage is that the gels will often breakdown over time (there are some "permanent" types of gels) allowing the flow of water to resume. Cement is a more permanent alternative but it cannot penetrate as deeply into the formation as the gels can. The disadvantage of cement is that once it is injected downhole, it cannot be removed like mechanical packers or plugs.

Subsurface Re-Injection. In addition to preventing water from reaching the surface, another method to avoid any water discharges to sea is to re-inject it into a subsurface formation. Before injection, the produced water must be treated. Solids and residual oil are usually removed through the use of traditional produced water treatment technologies. These components need to be removed to prevent plugging of the producing formation. Dissolved gases and organisms can present potential corrosion problems to produced water injection systems, and oxygen scavengers and biocide chemicals are traditionally used to treat these components. Once treated, high pressure pumps transport the produced water down injection wells where the water then penetrates the formation (NETL, 2010a). Not only does this option dispose of the unwanted produced water, but also aids in the maintenance of reservoir pressure enhancing sweep efficiency and ultimate oil recovery. However, injection of produced water is relatively rare in offshore operations due to its high operational cost and the use of scarce platform space.

Oil-in-Water Treating Technologies. As stated above, most offshore platforms are allowed to discharge produced water to sea provided that the produced water meets regulatory standards typically for oil and grease content. Discharge to sea is one of the most common methods for offshore produced water disposal. There are a number of different technologies available to treat produced water. Some widely used technologies can be separated into three general categories: conventional/gravitational separation, membrane techniques, and adsorbents. For the sake of brevity, only these types will be discussed in this paper, but many other additional technologies exist both in the United States and elsewhere in the world.

Conventional / Gravitational Separation. Conventional and gravitational separation technologies rely fundamentally on separation through the difference in densities of oil and produced water. These technologies are widely employed in oil and gas producing operations both in the United States and elsewhere in the world. The following are a few examples of the most common conventional and gravitational technologies.

- Hydrocyclones are one of the most widely used technologies used offshore in oil removal from produced water and they can also be used for particulate removal. Hydrocyclones have a cylindrical top and a conical base. Inlet fluids are fed tangentially into the cylindrical section of the device. The conical shape of the hydrocyclone causes formation of a vortex, producing large centrifugal forces on both the oil and water. Density differences between the two fluids result in different centrifugal forces, with the heavier water phase rotating on the outside of the cone and the lighter oil phase migrating to the inner part of the vortex. The oil phase exits towards the entrance of the cyclone with the water phase exiting at the base of the conical section. Hydrocyclones require only pressure drop as a driving force and can achieve a produced water quality of down to 10 ppm oil and grease content depending on several factors including inlet feed quality, oil/water chemistry, and system operating pressures.

- Centrifuges are similar to hydrocyclones in that they rely on centrifugal motion to separate oil and water, however, centrifuges require energy to rotate and impart the centrifugal forces on the fluids to be separated.

- Dissolved or Induced Gas Flotation devices operate by using a gas such as nitrogen, natural gas, or air to attach to oil and grease droplets, lowering the effective density, causing the droplets to rise to the surface of the flotation chamber where they can be skimmed off by a mechanical device. "Dissolved" and "induced" refer to the way in which the gas bubbles are generated. In a Dissolved Gas Flotation device, the produced water is saturated with the inert gas at a higher pressure then flashed to a lower pressure in the flotation unit, causing the inert gas to come out of solution. Gas bubbles are created by mechanical shears or impellers in an Induced Gas Flotation device. Flotation devices can achieve outlet water qualities of 20 to 40 ppm oil and grease content.

- Parallel and Corrugated Plate Interceptors (PPI / CPI) utilize tightly arranged plates to provide a large surface area for the coalescence of oil droplets. PPI plates are arranged with small spaces in between them, allowing for faster separation of oil and water with a short retention time. CPI plates have small holes in them, allowing the oil to coalesce on the surface and rise through the holes until the oil layer becomes thick, flowing over into the slop oil system. Outlet water qualities of 100 to 300 ppm oil and grease are possible.

Filtration / Membrane Techniques. Produced water can also be cleaned up through the use of filtration techniques involving different types of membranes or filters. These technologies are not as widely used in oil and gas producing operations as conventional or gravitational separation technologies with the exception of media filtration.

- Media Filtration uses walnut shells, sand, anthracite, or other granular materials as a filtration media. Walnut shells in particular are widely used in oil and gas operations to remove oil and grease from produced water. Removal of > 90% of oil and grease is possible and sometimes coagulants are injected upstream to increase removal efficiency.

- Micro- or Ultra-Filtration refers to a group of filters with pore sizes of 0.1 – 3 μm and 0.01 – 0.1 μm respectively. These filters have pore sizes small enough to remove suspended solids, bacteria, and algae. They are often used as a pre-treatment for electrodialysis.

- Reverse Osmosis (RO) membranes are used to remove dissolved salts. High pressure pumps are needed to provide the pressure gradient for the membranes to function properly. Thus far, only laboratory and bench scale tests have been conducted on produced water using RO membranes.

- Electrodialysis processes use stacks of ion exchange membranes in conjunction with an anode and cathode to separate the ions from dissolved salts in produced water. The cations migrate towards the cathode, while the anions migrate towards the anode. However, during the migration, cations are rejected by the anion exchange membranes and anions are rejected by the cation exchange membranes. This process results in a higher concentration of ions in one compartment in the stack, the concentrate, and a lower concentration of ions in another compartment of the stack, the diluate (OSPAR Commission, 2002; Colorado School of Mines, 2009).

Absorbents / Adsorbents. Adsorbent technologies employ different materials, resins, or immobilized fluids to selectively remove contaminants from produced water streams.

- In-line Coalescers can be used upstream of the aforementioned oil and water separation processes. Produced water is passed through a column or pipe packed with an oleophilic (oil-attracting) material. The coalescing material attracts the oil droplets, causing them to coalesce to a larger drop size and making it easier to remove them in downstream gravitational separation equipment. (OSPAR Commission, 2002; Colorado School of Mines, 2009; NETL, 2010b)

- Ion Exchange processes use acid or base resins to remove dissolved contaminant ions from produced water. The resins are pre-saturated with target ions of a non-contaminant nature that replace the contaminant ions in solution through reversible chemical reactions. Strong or weak acid resins are used to replace cations, while strong or weak base resins replace anions. Examples of active chemicals on acidic resins include sulfite groups, hydrogen carbonate, or organic acids with an example of an active chemical on a basic resin being an ammonia solution ($R\text{-}NH_3OH^-$). Regeneration of the ion exchange unit is easily achievable as these reactions are readily reversible. Greater than 90% rejection of target ions is achievable.

- Macro Porous Polymer Extraction (MPPE) units are a relatively new technology developed in the mid 1990s to remove dispersed and some dissolved hydrocarbons from produced water. A column packed with porous polymer particles coated with an immobilized extraction fluid is fed either produced water or condensed glycol regeneration overhead vapors. The extraction liquid on the surface of the polymeric material selectively captures hydrocarbon components from the liquid feed. Regeneration of the bed is achieved using low pressure steam, which is then condensed and settled by gravity to remove the hydrocarbon phase. MPPE systems sometimes utilize two columns, one in extraction mode and one in regeneration mode. Removal efficiencies of almost 100% have been achieved in both pilot and full-scale units due to the large surface area available for mass transfer, resulting in a very high number of theoretical equilibrium stages (OSPAR Commission, 2002; Colorado School of Mines, 2009; Meijer, 2001).

- Online Monitoring of oil and grease in produced water has been used as a surveillance or troubleshooting tool, but the accuracy and reliability of the technology has yet to progress to the stage where it can be used for on-line continuous compliance monitoring. A study into current online oil in water monitors was conducted on behalf of the Western States Petroleum Association (WSPA). Although none of the 26 monitors studied gave results equivalent to measured "oil and grease" as defined by US EPA Method 1664 and thus should not be used for official reporting, eight were deemed acceptable for use in offshore operations to monitor the process and aid in troubleshooting. These eight monitors all utilize the visual methods of UV fluorescence and IR light scattering to determine oil and grease content. The UV fluorescence method has been determined the best for online monitoring based on experience and end-user feedback (Tyrie and Caudle, 2007).

B. Air Emissions

A large number of technologies are being used by the oil and gas industry to minimize air emissions, and new technologies are continuously being developed and improved. In addition, there are several oil industry and government groups that monitor air emissions and share learnings on technologies and practices to reduce air emissions.

In the oil and gas industry, carbon dioxide and methane are the main contributors to greenhouse gas (GHG) emissions. Other types of gas emissions, from a regulatory perspective, include NMVOC (non-methane volatile organic compounds), nitrogen oxides and sulfur dioxide.

Carbon dioxide emissions are the largest gaseous release (in terms of mass) from the oil & gas industry (OGP, 2009). Emissions occur mainly from flaring and combustion of fuels for energy production. Carbon dioxide releases may also occur where the gas is used for enhanced petroleum recovery or where it is stripped from the natural reservoir gases to meet sales specifications.

After carbon dioxide, methane is the next largest emission (in terms of mass) by the oil & gas industry (OGP, 2009). It is emitted from sources including process vents, gas-driven pneumatic devices and tank vents. It also escapes as fugitive emissions from process components (valves, flanges, etc) that carry process streams containing significant quantities of methane. In addition, some methane emissions result from incomplete combustion of hydrocarbons in turbines, engines and flare equipment.

NMVOC emissions mainly occur from non-combustion sources such as venting and fugitive releases (including crude oil loading). In addition, NMVOCs are emitted in the exhaust of combustion equipment.

Sulfur dioxide emissions arise through oxidation during combustion of sulfur species that are naturally contained within hydrocarbon fuels or flared gas. Flaring of gases from the sulfur removal process represents one of the biggest sources of sulfur dioxide together with flaring of associated gas containing high concentration of hydrogen sulfide.

Emissions of nitrogen oxides occur almost exclusively from the combustion of fuels.

The main (continuous) sources of gas emissions in the oil and gas production industry are flaring, venting, fluids processing, combustion and fugitive losses (IAOGP, 2009). Intermittent and emergency emissions can arise from well testing and emergency flaring and gas venting.

Venting or Flaring. Associated gas brought to the surface with crude oil during oil production is sometimes disposed of at offshore facilities by venting or flaring to the atmosphere, in particular when there is no infrastructure to collect or market the associated gas. However, flaring or venting is also an important safety measure used on offshore oil and gas facilities to ensure gas and other hydrocarbons are safely handled in the event of an emergency, power or equipment failure, or other plant upset condition.

Alternatives to flaring/venting include selling the gas, re-injecting the gas into the reservoir, and utilizing the gas onsite. There are also technologies to reduce the volume of gas flared during overpressure events and to reduce gas emissions during flaring. None of these technologies are limited to offshore operations, although some are more commonly used offshore.

- Gas Sales. An alternative to flaring the associated gas is to sell it. The gas may also be transported to an onshore facility for liquefaction and sale as liquefied natural gas. The economic viability of selling the gas is dependent on the infrastructure available for gas collection and sales (e.g., transmission pipelines).

- Gas Re-Injection. The associated gas may be re-injected into the reservoir for disposal or for pressure maintenance to increase oil production or for later economic recovery. The viability of this practice depends on the type of reservoir and production fluids.

- Gas Utilization Onsite. The associated gas may be used onsite for energy needs and instrumentation. This practice would likely reduce but not eliminate the volume of gas vented/flared, since very often the volume of associated gas produced exceeds the onsite demand for gas.

- Flare Gas Recovery System. This technology recovers gas discharged into a flare system and compresses it back into the plant for use as feedstock, fuel or product, thereby reducing the volume of gas being flared.

- Flare Ignition. These technologies include ignition systems that do not require pilot flares, as well as efficient flare tips and systems that maximize the flare combustion efficiency, therefore reducing gas emissions. The technology in this area is continuously improving.

- High Integrity Pressure Protection Systems. These systems minimize the occurrence of overpressure events by using highly reliable and redundant instrumentation systems, thereby reducing or eliminating the need for emergency flaring. These systems are more common in offshore operations, although they are also used onshore.

PHYSICAL FOOTPRINTS OF PIPELINES

A. Design

Oil and natural gas export pipelines and related facilities are designed in accordance with standards and recommended practices developed by industry to ensure their safety and to minimize environmental impact. In many cases, additional company requirements are also used in pipeline system design. The minimum requirements for pipeline system design are provided in the Code of Federal Regulations (CFR). These regulations reference many of the industry standards and recommended practices.

The basic design considerations for pipeline systems are internal operating pressure, stability, collapse, environmental loading, and ability to withstand loads expected during the installation.

The industry standards and regulations referenced above set forth the requirements for selecting the pipe strength and thickness combination to withstand the expected internal operating pressures. Each pipeline segment has a maximum allowable operating pressure (MAOP) that must not be exceeded. The design of a pipeline includes a review of all sources into the pipeline to ensure they cannot exceed the MAOP of the pipeline. Pressure sensors are connected to control systems that shutdown pumps and/or close valves to isolate the pressure sources from the pipeline to prevent overpressure. In many cases, pressure relief valves are also installed for redundant protection. The BOEMRE requires adherence to the industry standard, API RP 14C "Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms", which provides guidance for the design of offshore process safety systems.

Offshore pipelines are typically connected to one or more fixed or floating platforms via a component known as a "riser". On a fixed platform, risers are typically connected to the platform's underwater structure. For floating platforms, a riser is supported by the platform and may be installed in a catenary (hanging-chain) configuration, i.e. "steel catenary risers" (SCRs) or in a vertical configuration, i.e. "top tensioned risers" (TTRs). Design specifications require a greater safety margin for risers than for the pipeline. A thicker wall and/or stronger material is selected to achieve the higher safety margin for internal operating pressure. Loads due to environmental loading are also considered in a riser design, including extreme storm events.

Other factors considered when selecting the pipe are stability and collapse. Stability design calculations ensure that a pipeline has adequate weight to overcome the effects of buoyancy and does not move during and after extreme environmental events such as a hurricane. Natural gas pipelines, due to the lower density fluid being transported, are generally more prone to movement and may require concrete weight coating to ensure they are stable. Collapse design calculations ensure that a pipeline does not collapse when exposed to pressures in deep water with atmospheric pressure inside the pipe. Another consideration for pipe design is the method used to install the pipeline as the highest stresses can occur as the pipe is being lowered from the installation vessel to the seafloor.

A protective external corrosion-resistant coating is applied to offshore pipelines. Typically a fusion-bonded epoxy is used for new designs. Sacrificial anodes made of aluminum alloys are typically attached to the pipeline at calculated spacing to provide cathodic protection (CP) to prevent corrosion of any uncoated areas. A more robust coating system is typically applied to risers where they transition through the changing water/air interface at the surface, known as the "splashzone." This coating prevents corrosion of the pipe in this area. Protective structures, commonly known as "riser guards," are typically installed around the risers in the splashzone to protect them from impact from vessels.

Pipelines in less than 200 feet water depth are buried to 3 feet of cover to provide additional protection. Certain coastal states require a minimum 4 feet of cover in state water limits. Pipelines crossing shipping fairways and anchorage zones are buried even deeper.

A critical consideration of offshore pipeline design is the route selection. A route assessment is performed to identify other pipelines that will be crossed, existing platforms, lease blocks, and geological features to avoid, etc. The assessment includes a field survey using sidescan sonar to collect data along the proposed route to confirm the location of other pipelines and identify any environmentally sensitive areas and/or seafloor features to avoid. The route assessment identifies all potential hazards along with the planned mitigations

The items above provide only an overview of the design considerations for a pipeline and related facilities. There are many industry standards that provide guidance for the design of a pipeline and its components.

Permit applications for pipelines installed in federal waters are submitted to the BOEMRE for approval. Those applications address the pipeline and facilities design criteria described above.

B. Construction

Industry standards and practices, as well as regulations, also define construction requirements. The requirements for weld inspection and welder qualifications are defined as well as requirements for testing the completed pipeline. Pipelines are typically tested with water to a pressure at least 125% of the MAOP. Natural gas risers are typically tested to 150% of the MAOP.

Construction of a typical offshore pipeline involves a "pipelay" spread and a "hook-up" spread. The pipelay spread includes the vessel used to lay the pipe and all supporting tugs, supply vessels, remotely operated vehicle (ROV) vessels, etc. The hook-up spread includes any vessels necessary to connect the pipeline to existing or new infrastructure on each end. A wide range of equipment may be used for either operation depending mainly on water depth and size of pipeline being installed. Installation of shallow water systems (typically less than 800 feet water depth) can be supported by divers. A large percentage of offshore pipelines are located in less than 800 feet water depth. Deeper water installations must be supported by ROVs. For ROV installed components, prior to shipping, a manufacturer's acceptance test is completed. Additionally a systems integration test (SIT) is completed onshore prior to their installation offshore. The SIT is typically a full-scale onshore trial run of the equipment and is designed to ensure the equipment will perform as designed prior to installation offshore.

One of the most critical tasks when installing a new pipeline is avoiding existing infrastructure (pipelines, platforms, etc.) when deploying any anchors or other means to secure a construction vessel to the seafloor. The Hazards Survey completed in the design phase identifies these existing features to avoid. The BOEMRE maintains a database of coordinates for all pipelines in federal waters. This database is updated continuously and is made available to the public. The pipeline company installing a new line typically provides any third parties the opportunity to be present when anchors are deployed near their lines. The GulfSafe system, as discussed later, has recently been implemented to provide notification to operators of intended activities near a pipeline. The system operates similar to the onshore one-call system (811).

When construction vessels are working in the vicinity of a platform, a simultaneous operations plan (SIMOPS) plan, or equivalent, is developed to list the activities of all construction spreads onsite and assess to ensure there are no conflicts or safety concerns if the work is performed simultaneously. The SIMOPS plan and the Permit to Work system ensure adequate communication between the vessel(s) and platform(s), which is essential for a safe operation.

Detailed installation procedures are developed for offshore construction, whether in deep or shallow water. Detailed pipelay procedures are developed prior to mobilization to ensure the stresses on the pipeline during installation are within acceptable limits considering the pipe properties, installation vessel characteristics, and sea conditions. A Hazards Identification (HAZID) process is used to identify potential hazards that may be encountered and addresses means to mitigate any construction risks identified. HAZIDs are particularly important when connecting a new system to an existing system that contains hydrocarbons.

Company representatives are present on the construction vessels while the work is being conducted to provide assurance that the work is being executed as designed and in accordance with the installation procedures.

C. Operations

Offshore export pipelines are typically monitored and controlled by personnel in control rooms using SCADA (Supervisory Control and Data Acquisition) control systems. The pipelines are monitored continuously for pressure, flow rate, sediment and water, temperature, and operational status of valves and pumps. Valves and pumps are controlled to open/close, enable/start, or disable/stop upon command to maintain normal operating pressure and flow rate conditions. Data communications to/from the offshore platform and the onshore control room is typically provided via satellite (VSAT) or microwave technology.

The SCADA system uses the real-time pressure and flow rate data and continuously calculates the pipeline's "line balance", which is the measured volume leaving the pipeline versus the measured volume entering the pipeline, to detect leaks from the pipeline. The SCADA system alarms the control room personnel of imbalances in the calculated "line balance", as well as any other abnormal operating condition such as high pressure. Upon receiving indication of an abnormal condition, control room personnel are trained to take action, up to and including shutdown of the pipeline and valve isolation, to protect the safety of local personnel and the environment. SCADA-controlled pipelines can typically be shutdown and isolated from production sources very quickly.

Offshore platforms can utilize HERO (Hurricane Evacuation Remote Operations) technology that enables the orderly shutdown during hurricane force winds if data communications fails. This enables the safe evacuation of local personnel further in advance of a potential storm and assures the platform will be shutdown, thereby minimizing an environmental threat, if the control room personnel lose the capability to send SCADA commands.

Advances continue in leak detection technology using SCADA control systems. In particular, statistical leak detection models are being considered for offshore pipeline systems that may improve the detection capabilities i.e. detect smaller leaks or detect leaks more quickly than traditional line balance calculations.

D. Inspection and Maintenance

In addition to properly designing, installing, and operating a pipeline system, it must also be maintained properly. Routine maintenance items include inspection and calibration of overpressure protective devices at least yearly including pressure sensors, relief valves, and shutdown valves. The cathodic protection system is also evaluated to ensure it is working properly. Inspections of pipeline components on a platform above water are completed as part of routine surveillance checks. At least yearly, a detailed assessment of components above water (risers and topside facilities) is completed to ensure there are no issues with the protective coatings. Aerial surveillance using fixed wing aircraft or helicopters is also completed on a periodic basis to note any encroachments on the pipeline route or any signs of leakage. Where offshore pipelines transition to land, depth of cover surveys are completed to ensure pipelines are buried adequately out to at least 15 feet water depth so they do not pose a hazard to marine traffic.

Cleaning tools know as “pigs” are routinely run through pipelines to remove wax that may have deposited on the pipe walls and any other sediments depending on the service of the pipeline. These tools also remove any water from the line to prevent it from causing internal corrosion. Internal Line Inspection (ILI) tools, also known as “smart pigs,” are also run on critical systems to identify any internal or external corrosion and/or damage from third parties such as dents, gouges, etc.

Prior to a storm passing through the Gulf of Mexico, pipelines are typically shut down using pre-defined shutdown procedures. This shutdown requires close coordination between producers and pipeline operators.

After a hurricane passes over a pipeline and related facilities, the BOEMRE typically issues a Notice to Lessees (NTL) requiring operators to inspect pipelines and platforms within a defined corridor affected by the storm. The NTL also sets forth requirements for stand-up tests prior to returning these systems to operation. The required pipeline inspections include locations where one pipeline crosses another, locations where one pipeline connects to another subsea, risers on a platform, and topside facilities. Platform structural inspections are also required. Pipeline companies typically utilize sidescan sonar equipment to assess the subsea crossings and tie-ins to determine if any damage has occurred. Any damage found is reported to the BOEMRE and repair plans submitted for approval as appropriate.

Many pipeline operators have an inventory of equipment for completing subsea repairs, especially if a system has a unique size or operating pressure such that the equipment would not be readily available. Deepwater mainline systems generally have a complete ROV-installed repair system in stock including all required end connectors, repair jumpers, etc. Several deepwater repairs have been successfully completed to date with ROVs. The tooling and hardware required to complete these repairs is improving continuously as more suppliers enter into this market. There are also shallow and deepwater repair systems that have been manufactured by third parties and made available to operators that pay a yearly fee.

E. Subsea Pipeline Integrity

Sustainable use of subsea pipelines requires that working lifetimes are maximized for commercial success at the same time that environmental risks are minimized through robust designs, conservative operations, regular inspections and detailed planning and scheduling of maintenance. Proper management of risk can provide subsea pipelines with safe a reliable working lifetimes of 30 years or longer.

Routine maintenance items include inspection and calibration of overpressure protective devices at least yearly including pressure sensors, relief valves, and shutdown valves. The cathodic protection system is also evaluated to ensure it is working properly. Inspections of pipeline components on a platform above water are completed as part of routine surveillance checks. At least yearly, a detailed assessment of components above water (risers and topside facilities) is completed to ensure there are no issues with the protective coatings. Aerial surveillance using fixed wing aircraft or helicopters is also completed on a periodic basis to note any encroachments on the pipeline route or any signs of leakage. Where offshore pipelines transition to land, depth of cover surveys are completed to ensure pipelines are buried adequately to at least 15 feet water depth so they do not pose a hazard to marine traffic.

Cleaning tools know as “pigs” are routinely run through pipelines to remove wax that may have deposited on the pipe walls along with any sediments associated with the production stream. Pigging tools also remove any water from the line to prevent it from causing internal corrosion. Internal Line Inspection (ILI) tools, also known as “smart pigs,” are also run on critical systems to identify any internal or external corrosion and/or damage from third parties such as dents, gouges, etc.

A case study of the Forties Field pipeline system in the North Sea (Marsh et al., 2008) included both oil and multiphase lines with proven service of 33 years and potential service as much as another 20 years beyond their design lifetimes. As emphasized by Marsh et al. (2008), lack of obvious degradation in topside components of riser connections is no guarantee of integrity in subsea components; direct subsea inspections are essential. Factors needed for success include intelligent pigging and the establishment of key performance indicators for corrosion resistance.

F. Public Awareness and Damage Prevention

Damage from external forces is one of the primary causes of significant spills from offshore pipelines. Many of these spills are the result of damage caused by a weather-related event such as a hurricane. After these types of events, pipeline operators work to prevent damage and improve emergency response. Following Hurricanes Katrina and Rita, pipeline operators held workshops and meetings to share learnings and identify improvement areas for damage prevention and emergency response. Operators identified a number of ways to improve communications, pre-event planning and resource deployment. A major learning was the need to upgrade mooring systems used by mobile offshore drilling units. These units caused significant damage to a number of pipelines when the unit broke free of their moorings. Subsequently, industry and regulators worked together to develop upgraded recommended practices for the use of moored drilling rigs.

Another primary cause of spills are third parties, such as work boats, spud barges, jack-up rigs, fishing boats, or other vessels performing routine operations or marine activities To address this issue, industry is bringing into play mitigation methods commonly used in onshore operations – public awareness outreach and One-Call Systems.

Public awareness programs are effectively used to enhance safety and environmental protection through increased communication outreach, awareness and education. Information shared with various stakeholders such as drilling organization, marine excavators, emergency response organizations, public officials and other interested parties help them better understand the important role they can play in contributing to offshore pipeline safety and damage prevention.

Additionally, many pipeline operators participate in an industry coalition called the Coastal and Marine Operators (CAMO) Pipeline Industry Initiative. CAMO was formed in 2009 to explore and take action on issues and challenges in preventing spills, releases and damage to offshore pipelines. CAMO's initial focus is to develop and implement a marine pipeline damage prevention and public awareness program for mariners and vessel operators. The objective of the program is to educate the maritime community about pipeline locations, damage prevention and how to respond appropriately in the event of an emergency. CAMO has produced educational materials and representatives are presenting their damage prevention and public awareness program at various national and regional conferences and meetings.

One-Call systems are centralized communications systems used for the purpose of notifying underground facility operators of pending excavations. Federal and State laws and regulations codify the requirements governing these systems and their use. In 2007, a national call-before-you-dig number (8-1-1) was established to provide one number that can be called prior to initiating excavation activities. When calling 811 from anywhere in the country the call is routed to the State One-Call Center. Though One-Call systems have proven to be effective for onshore pipelines, no such system existed for addressing offshore excavation activities in the OCS until recently. In February 2009, a new one-call system, GulfSafe, began operation with a goal of eliminating preventable damage to the subsurface infrastructure. Currently the system is operational in the Gulf of Mexico and Straits of Florida and has plans for expanding the system to other offshore areas. CAMO is helping educate the maritime community on the importance of using 8-1-1 and the GulfSafe system.

G. Regulatory Framework and Jurisdiction

Comprehensive pipeline safety regulations exist for both onshore and offshore pipelines covering all phases of a pipeline's life. These regulations contain requirements including corrosion control, reporting, design standards, construction methods, operational controls, pressure testing, maintenance standards, qualification of personnel and emergency response. For onshore pipelines, the Department of Transportation (DOT) has the primary responsibility for pipeline regulation but additional regulations are imposed by many State and local agencies. Regulations directed at safety and environmental protection for pipelines located on the Outer Continental Shelf (OCS) are shared between the DOT and the Department of the Interior (DOI).

The DOT, through its Pipeline and Hazardous Materials Safety Administration (PHMSA), is responsible for establishing and enforcing safety standards for the nation's pipeline transportation system. PHMSA establishes and enforces minimum safety standards for the design, construction, operation and maintenance of pipeline facilities pursuant to 49 U.S.C. 60101 et seq.

BOEMRE, which is part of the BOI, is responsible for issuing and enforcing regulations to promote safe operations, environmental protection, and resource conservation on the OCS. BOEMRE is responsible for granting pipeline rights-of-way through submerged lands of the OCS. In addition, BOEMRE regulates pipelines under the jurisdiction of the DOI in accordance with policies, practices, and requirements issued under 30 CFR Part 250, Subpart J.

To avoid duplication of regulatory effort for pipelines on the OCS, in a Memorandum of Understanding between DOT and DOI dated December 10, 1996, each party's respective regulatory responsibilities for pipelines on the OCS are outlined. The DOT is responsible for establishing and enforcing design, construction, operation, and maintenance regulations, and for investigating accidents for all OCS transportation pipelines beginning downstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. The DOI's responsibility extends upstream from the transfer point described above. However the BOEMRE retains the responsibility to review and approve all OCS pipeline applications.

PRODUCTION FACILITIES AND PIPELINES IN ARCTIC ENVIRONMENTS

A. Arctic Offshore Structures

Oil and gas platforms have operated in ice covered areas for nearly 50 years. One of the earliest platforms was installed in the Cook Inlet near Anchorage in 1964. It had to resist winter ice that was pushed against the four platform legs by the incredible 30-foot tidal range of the area. An engineering marvel of the day, these platforms are still in service today, demonstrating the ability to design for harsh environments and stand the test of time. The tide cycles twice a day pushing ice up to three feet thick to be crushed against the platform legs. The platforms special design locates the production wells inside of the protective legs.

More severe ice issues can be found above the Arctic Circle. The Canadian and US Beaufort Seas and the Chukchi Sea were studied extensively during the 1970s, 1980s and again since 2000. In those seas, the ice is much thicker and can include multiyear ice that has survived through Arctic summers to become stronger. This strengthening is due to the natural reduction in salt content that occurs over time and the fact that freshwater ice is stronger than saltwater ice. Many studies have revealed how the ice moves, how thick it is, how strong it is, and how much force it applies to structures.

Ice-strength data have been collected over decades to help build a broad knowledge of loadings, ice-failure mechanisms, and probabilities of seeing extreme events. Many studies have been performed on strength measurements of ice in the field, including ice-loading measurements on platforms, bridges, light houses, and even small islands. Understanding has progressed on the differences between local peak loadings and global loadings on structures. Scale-model testing of structures, as performed in ice tanks, serves to verify understanding of ice loadings and ice-failure mechanisms.

Previous standards for design of structures in the Arctic are expected to become supplanted by the oil and gas industry standard known as ISO 19906:2010. The new standard specifies requirements and provides recommendations and guidance for the design, construction, transportation, installation and removal of offshore structures, related to the activities of the petroleum and natural gas industries in Arctic and cold regions.

Variations Based on Resource Type and Location. Platform designs for icy conditions will vary depending on: water depth, ice thickness, ice type, ice movement, and other variables. The environment of a particular location will determine the best platform options to be considered. There are some basic designs that can be considered in ice prone areas:

- Gravel Island. Gravel Islands are best suited for water depths less than 60 feet. These "platforms" are composed of gravel placed on the seafloor and rising above the water's surface. They typically include some form of protection for erosion on the slopes of the island that can take the form of sand bags, rip rap, concrete mats, or sheet piling. Gravel island design is similar in many respects to the design of earthen dams. Instead of resisting the pressure of water, the island must resist the action of ice that can approach from any direction. In practice, the load-carrying capacity of an artificial island is seldom a limiting factor. Practical island sizes are more than adequate to resist global ice loadings. The most important challenge in design is to understand the propensity for local damage to the island from ice impacts and the potential for ice ride-ups, pile-ups and encroachments that can impede operations and potentially damage surface equipment. Gravel islands are a proven option for offshore development, but are known to require substantial annual maintenance and repair.

- Jacket Structures. Jacket structures are mostly used in temperate climates. The Gulf of Mexico is home to thousands of steel jacket platforms. A steel jacket is constructed of welded tubular steel elements. The jacket is an efficient way of using proven construction techniques to make a structure that is strong for resisting lateral loads generated by ocean waves but presents a minimal profile to allow waves to pass through with minimal energy transfer to the platform. Jackets are built on land, usually in a single piece, and floated to the offshore site aboard a cargo barge from which they are usually lifted and occasionally launched into the ocean. A pile foundation supports the weight of the jacket above the soft ocean bottom and aids in resisting the forces imparted by the ocean waves or currents by transferring those forces safely to the ocean floor. Large drilling and production facilities can be supported atop the jacket structure and numerous wells can be safely held within the confines of a protective jacket.

  Typical jacket structures are not well-suited to areas prone to sea ice. Jackets can be designed to resist some contact with very light ice, but not the ice present in Arctic regions. An adaptation of the common jacket structure has been used in ice-susceptible regions such as Alaska's Cook Inlet, based on a steel tower structure with enlarged vertical legs to house wells and protect them from ice. Structural bracing between the legs is minimized and eliminated in the area adjacent to the waterline where it would be susceptible to damage from ice.

- Gravity Based Structure. Gravity-based structures (GBS) have been used in various places around the globe. These are large structures that function simply by resting on the ocean bottom. GBS platforms are characterized by a broad flat surface across the base that distributes the weight of the platform evenly across the ocean floor and spreads that weight over an area so large that the sea bottom can easily support the weight and any eccentric forces occurring when the platform is acted upon by ice, waves, currents, earthquakes or other environmental actions. The GBS is proportioned so that the weight of the platform is great enough and spread over an area large enough so that tipping or overturning is certain not to occur. GBSs have been commonly constructed of concrete and occasionally of steel or some combination of the two materials. GBS platforms are most common in harsh environments and remote areas. As a result they tend to be large and associated with world-class developments. Considerations such as large storage requirements and extended functionality drive the design.

  Because of their size, GBS structures are usually self-floating and brought to the offshore development site fully integrated with drilling and production equipment to help minimize the platform-construction activities that otherwise would occur offshore. The single column of a GBS makes it ideal to resist the most severe Arctic ice conditions in shallower water depths (~300 feet or less).

- Spar. Spar platforms have been proven for deepwater applications. Spar platforms are an outgrowth of the spar buoy concept, which employs a long, slender and generally cylindrical shape extending deep into the water. The deep draft and distribution of mass throughout the spar give it intrinsically stable characteristics. Motion characteristics for the spar platform can be adjusted during design to suit the service requirements for the facility. Spars have yet to be used as an Arctic platform, but R&D activities for deepwater Arctic developments have focused the spar as a candidate solution. One different feature for an ice resistant spar is the likely implementation of a conical shape through the waterline which would help to force ice to break downwards taking advantage of the weaker resistance presented by sheet ice when subjected to out-of-plane vertical forces.

Success in the Field. Shell has had a number of successful platforms that have proven themselves in arctic conditions:

- The Cook Inlet platforms installed in the 1960s.
- The gravel islands that were constructed in the Beaufort Sea to support exploration drilling in the 1980s.
- The Molikpaq drilling platform that was used in the Canadian Beaufort in the 1980s and now serves as a production platform (Piltun-Astokhskoye-A platform) for Shell's Sakhalin development.
- The pair of 4-column concrete GBS platforms (Lunskoye -A and Piltun-Astokhskoye-B) built for the Sakhalin II development in icy, yet still subarctic conditions.

Platforms designed for ice loading cost more and; therefore, there will be fewer platforms for harsh ice environment developments than might occur in milder conditions. Techniques like extended reach drilling will be used to allow wells to reach farther from a central platform and access more oil or gas from one location.

B. Arctic Pipelines

Offshore Arctic pipelines presently exist in the State of Alaska. The existing offshore Arctic pipelines located in Alaska transport produced fluids (oil & gas), diesel and fuel gas/natural gas. Offshore Arctic pipeline design, engineering and construction are truly unique from offshore pipelines located in the Lower-48 (L-48) USA states.

Typically an enormous amount of resources are dedicated to gather site-specific information on Arctic conditions. Data from environmental science programs, meteorological-oceanographic (metocean) programs, ice monitoring, and geotechnical programs are all necessary inputs to

Arctic pipeline design. Traditional knowledge (defined in this context as historical and cultural experience of native peoples) is also an important input to Arctic pipeline design. Arctic pipeline design needs to sufficiently address natural phenomena like strudel scouring and ice gouging that do not occur in ice-free regions.

Offshore Arctic pipelines have historically been designed with a Pipe-In-Pipe (PIP) system. The PIP design provides for secondary containment. PIP design is not the only way to provide additional environmental protection. Greater wall thicknesses and stricter welding criteria also can be specified to mitigate environmental risks.

All of the near-shore Arctic pipelines have been constructed from land-fast ice in the winter time. Using land-fast ice as the construction work platform minimizes the environmental footprint. Ice roads are also created to support construction. A robust pipeline inspection program is implemented during Arctic pipeline construction to ensure the asset is constructed in accordance with the plans and specifications.

Offshore Arctic pipelines utilize many of the same operations and maintenance techniques that are utilized in the L-48. The use of intelligent pigging is an excellent tool to mitigate environmental risk. In addition, redundant leak detection systems provide environmental protection.

Industry has an active Research and Development (R&D) Program for offshore Arctic Pipelines. In particular, there is ongoing R&D work in the area of Pipe/Soil/Ice Interaction modeling. Arctic Pipeline welding is also an area where Joint Industry Projects (JIPs) are ongoing. Lastly an enormous amount of Arctic Oil Spill Prevention and Response (OSPR) R&D is ongoing. Specifically, an organization called International Petroleum Industry Environmental Conservation Association (IPIECA) has a very active R&D program in the area of OSPR. Individual operators and producers have many R&D Arctic research activities ongoing as well. Shell recently conducted a spill response project call Aerotorch. Lastly, the BOEMRE also has a very active R&D program in the area of OSPR.

SAFETY AND ENVIROMENTAL PROTECTION

Constructors and operators of offshore platforms recognize the need to further reduce physical footprints of the platforms and their possible effects on marine environments. In that regard, the challenges of Arctic offshore platforms have become some of the leading-edge motivators for further improvements. Examples of potential improvements of broad applicability, which originated in Arctic applications, include:

- Application of sound-reduction technology – a concrete and steel outer skin is a likely option for its sound attenuation properties thus reducing potential impacts to marine mammals.

- Alternative options for foundation design including adaptation of suction installation for foundation elements – an outgrowth from recently matured techniques for installing deepwater foundations. This will help reduce environmental footprint by reducing or eliminating the need for foundation preparation activities (dredging) and facilitating platform extraction and salvage at the end of field life.

In time, platform designs will take advantage of standardization. After each successful project, lessons learned can be rolled into future design. This will eliminate some of the inefficiency and conservatism likely to be incorporated in the first designs while also reducing risks associated with suboptimal early features that will be identified through field experience. Initial deployments will include extensive instrumentation systems that will focus primarily on collecting invaluable information on the performance of structures in heavy arctic ice. This information will be used by designers in the development of second generation designs.

The pipeline industry recognizes that even though the industry's overall safety record is good, there is always room for improvement. In addition to the mitigation measures currently taken to achieve safety and environmental protection, new technology and improved practices are continually sought by the industry. Examples of these voluntary efforts include:

- Actively participating in developing standards and recommended practices (i.e. American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), NACE international, and other similar organizations) to improve design, construction, operation and maintenance.

- Actively participating in organizations that promote safety and environmental protection, such as the Common Ground Alliance (CGA), a nonprofit association that promotes damage prevention practices for all underground utility industry stakeholders, and the Coastal and Marine Operators (CAMO) Pipeline Industry Initiative, a nonprofit organization whose purpose is to explore and take action on issues and challenges in preventing spills and preventing damage to offshore, coastal and marine pipelines.

- Investing and leading research and development efforts to develop new technologies and practices to confront offshore pipeline challenges and improve the industry safety record even further. Many operators do this through the Pipeline Research Council International (PRCI), a not-for-profit corporation comprised of 37 energy pipeline companies from around the world which focuses on integrity and reliability solutions to pipeline design and operating problems.

- Learning from pipeline incidents and sharing ideas for improvements and best practices throughout the industry. The industry has standing teams and workshops to discuss incidents and near-misses, analyze data, share best practices, and make recommendations to executives.

- Actively participating in the API Pipeline Performance Tracking System (PPTS). Since 1999, PPTS has collected and analyzed detailed spill data and made recommendations to industry. Onshore and offshore pipeline operators representing 85 percent of regulated pipeline miles participate in PPTS.

Through these efforts, advances continue to be made in developing new and improving existing mitigations that can be put in place to achieve safety and environmental protection for pipelines.

FINDINGS

Offshore production platforms and subsea pipelines account for the two most significant categories of physical footprints of oil and gas developments in marine environments. Alteration of the seafloor is unavoidable during construction of subsea pipelines although constructors have endeavored to make the pipelines as operationally reliable and environmentally compatible as current technology allows. Construction of platforms disturbs the seafloor to different degrees depending on whether the platform is designed to float or to rest on the seafloor; design and construction of an individual platform depends on many factors that include water depth and whether ice could be an operational hazard.

Environmental aspects of platform operations include management of wastewater as well as air emissions. Pipeline operations emphasize leak avoidance through continuous monitoring and remote control along with regular inspection and maintenance.

Specific findings include:

- Key technological developments for continuing progress on offshore platform operations emphasize equipment and techniques for subsea flow-assurance and separation. Progress in surface-based technologies also is expected but the largest, value-added advancements are needed to lengthen the working lifetimes and reduce the maintenance intensity for subsea systems.

- Wastewater handling on offshore platforms will continue to require site-specific choices among multiple, permitted alternatives; no single waste-disposal approach will be optimum for all situations.

- Offshore wastewater treatment and disposal can be addressed by several different physical and chemical technologies, all of which can be further improved. But a key point of emphasis is work to reduce overall volumes of wastewater generated so that treatment and disposal becomes less urgent overall.

- Air emissions from offshore production facilities include several different combustion, venting, and flaring sources. Those sources have been found to not significantly affect coastal areas but should continue to be monitored to ensure that the favorable non-impact finding does not change. BOEMRE has a good system of permitting air emissions from offshore platforms that is protective of onshore air quality and has made significant progress in reducing natural gas (methane) venting emissions.

- Pipelines have proven to be the safest, most reliable, economical and environmentally favorable way to transport oil and gas throughout the US, including offshore developments The aging of the pipeline infrastructure suggests that continual improvement in system integrity, monitoring, and leak-detection is necessary.

- Subsea pipelines will benefit from improved technologies that are different from, but complementary with, improvements being pursued for subsea systems connected to production platforms. But pipelines further will benefit from increased public awareness, and industry attentiveness, to pipeline locations so that damages to pipelines can be avoided and environmental threats from leaks thereby reduced.

- Arctic offshore platforms and pipelines must be designed and constructed to withstand hazards from ice but otherwise Arctic offshore structures share many of the same technologies and techniques with their temperate-region counterparts. Arctic applications are not unproven, as sometimes is assumed outside industry, and have operated in offshore Alaska since the 1960s.

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APPENDICES

A. Appendix 1: Glossary

BOEMRE. US Bureau of Ocean Energy Management, Regulation and Enforcement. As of June 2010, BOEMRE (sometimes shortened to BOEM) is the successor to the former Minerals Management Service (MMS).

DOI. US Department of the Interior.

DOT. US Department of Transportation.

E&P. Exploration and production activities involving discovery, evaluation and recovery of oil and gas resources.

GBS. Gravity-based structure. A variety of offshore oil and gas platform that rests on the ocean bottom and is stabilized by its own weight.

GoM. Gulf of Mexico.

HAZID. Hazards identification. Generally refers to a coordinated plan to identify, avoid or mitigate hazards during subsea construction work.

HERO. Hurricane Evacuation Remote Operations. An automated control system that provides for orderly shutdown of subsea pipelines during emergencies, especially if normal SCADA-controlled processes are impaired.

MAOP. Maximum allowable operating pressure.

MMT. Marine Magnetotellurics. A non-seismic exploration method that uses naturally occurring electrical currents in the solid-earth layers, which are induced by Earth's magnetic field, to differentiate resistive from non-resistive geologic bodies as a way to narrow the search for hydrocarbons.

NEPA. National Environmental Policy Act (NEPA). US federal legislation, dating from 1970, that provides for an environmental impact statement (EIS) as a core requirement of federal regulatory agencies that are responsible for permitting infrastructure projects, including oil and gas exploration and development.

NMFS. US National Marine Fisheries Service.

NMVOC. Non-methane volatile organic compound (a category of air emission).

PEIS. Programmatic Environmental Impact Statement.

R&D. Research and development.

Riser. A pipe that connects a subsea well to a drilling, production or processing structure at the surface.

ROV. Remotely-operated vehicle. An underwater vehicle equipped with cameras and other sensors, as well as some external manipulators, which is operated from shipboard work stations in order to accomplish sub-sea observations and inspections.

SCADA. Supervisory Control and Data Acquisition. A general term for a system of electronic sensors, actuators and displays that enable operators to remotely monitor and control subsea infrastructure.

SCR. Steel catenary riser. A horizontally-configured riser, based on the stable shape of a hanging chain, which used to connect a subsea pipeline to a surface production platform.

Seismic. Physical analyses involving transmission and reflection of sound waves ("sounding") to decipher sub-surface geologic structures. Natural seismic waves are generated by geologic phenomena that include earthquakes, landslides and volcanic eruptions. Anthropogenic (human-generated) seismic waves, as used in subsea exploration, include those generated by air guns and vibrators operated from ships.

SIMOPS. Simultaneous operations. Generally refers to a coordinated plan to assure that multiple offshore activities and vessels do not create interferences during subsea construction work.

SIT. System integration test. An onshore quality-assurance test of pipeline components prior to subsea installation of the pipeline.

Sonar. Physical analysis involving transmission and reflection of sound waves to determine ocean bottom depths and sub-sea topography. Sonar waves are distinguished from other seismic waves by frequency and intensity. In offshore oil and gas activities, sonar commonly is used to detect and map underwater hazards prior to subsea construction work.

TTR. Top tensioned risers. A vertically-configured riser used to connect a subsea pipeline to a surface production platform.

VOC. Volatile organic compound (a category of air emission).

VSP. Vertical seismic profile. Seismic data acquired from a seafloor borehole using instrumented cables lowered vertically down the borehole as listening devices for a seismic source located above the borehole.

WAZ. Wide-azimuth seismic survey.