Subsea Innovative Processing and Design

Tuesday, 17 August 1422 - 1612 610 Technical / Poster Session

This session will focus on the subsea processing and design aspects of deep-water subsea installations. It includes introducing the innovative process, methodology, technology development, experiences, and lessons learned for subsea facilities. The practice of locating boosting, separation, and gas compression equipment on the seabed continues to gain momentum. Several successful projects will be presented that deliver on the long-promised goal of increased production and reliability. In addition, attendees will see the very latest in subsea processing technology that promises further gains in cost, efficacy and reliability.

Chairperson(s)

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Sponsoring Society:

Marine Technology Society (MTS)
American Institute of Chemical Engineers (AIChE)

Key Technology Qualification For Increasing Subsea Well Production Via Drag Reducing Agents

Abstract

Drag reducing agents (DRAs) are a cost-effective method to reduce pipeline pressure losses and maximize flowrates of onshore and offshore pipelines with over 40 years of proven results. With recent developments, production can also be significantly increased by injecting DRA into flow restricted subsea flowlines. This paper will provide a summary of the development and testing of a full-scale prototype subsea DRA storage and injection unit built to achieve the industry goal of alleviating flow restricted subsea pipelines. While DRA applications are proven in thousands of offshore and onshore applications, it has never been successfully injected subsea. System integration testing (SIT) is currently under way on the prototype unit, after which it will be qualified for offshore use. The technology is covered by numerous patents issued and pending in the US and other countries.

Introduction

Drag reducing agents (DRAs) have been increasing throughput by reducing pressure losses in onshore and offshore pipelines with over 40 years of proven results. Introduction of DRA at the subsea drill center has the potential to significantly increase production for far less cost by creating higher flowrates in existing subsea production lines, subsea gathering lines, and subsea trunk lines than drilling additional wells or laying new production and gathering lines. The future of offshore will continue to be about more, better, and cheaper subsea tiebacks to keep existing hub-class platforms full. Traditionally, keeping the hubs at full capacity calls for drilling more subsea wells at great expense. However, some field tiebacks are limited by platform weight limits due to hang-off loads associated with new risers. Deployment of DRA in existing subsea flowlines will offer operators the potential to increase their production. Higher production rates are achieved as the DRA reduces the flowline back pressure on the well and allowing it to flow more freely. DRA applications are proven over decades of use in thousands of offshore and onshore applications, and with a successful SIT, hundreds of subsea wells may also benefit from DRA application.

Currently there are no industry standards or recommended practices for subsea chemical storage and injection systems. Existing subsea systems are small scale (typically 1200 gallons), deployed on a temporary, short-term basis for remedial work. While components of these systems may be re-usable, they are generally considered single use systems utilized only while surface vessels are on location. The subject system is specifically designed and engineered to store much larger volumes (200 bbls increments), for extended periods and to inject DRA that has special design requirements, differing from requirements of typical subsea production chemicals. As such, a great deal of effort was expended surveying and reviewing existing standards and recommended practices (including those from military duty) for the various components that could be adapted as best fit for purpose for sub-assemblies as well as the overall system. To the extent possible, common off the shelf (COTS) components were specified and sourced that met API, ASME, IEEE, DnV and other recognized standards. The subject system was designed with a focus on flexibility regarding injection rates, autonomy, and reliability. The components were then built into sub-assemblies which were tested, then integrated into a complete unit. The full-size prototype unit is currently passing through a factory acceptance test (FAT), which will be followed with a full system integration test (SIT) where the unit will be completely submerged in an onshore test tank with underwater camera and full performance documentation. Select subject matter experts (SMEs), including regulators have been involved with peer level analysis and reviews.

The system design facilitates modular industrial fabrication techniques, supporting frequently encountered local content requirements. The system with its dual barrier, pressure compensated storage is qualified for 10,000 fsw. These features support a design one, build many, business model to lower unit cost, reduce parts count, and simplify maintenance. The unit is readily installed and recovered with a traditional dynamically positioned (DP) multi-purpose support vessel (MSV), which allows economical inspection, maintenance, and repair (IMR) to take place onshore with the ability to upgrade equipment as technology progresses and cost effectively adjust to ever-changing field requirements. Following the completion of the current SIT, and with compelling case study results, operators/producers have expressed interest to move forward with offshore deployment of the prototype unit in the near future, potentially generating large production rate increases.

The value proposition for localized subsea storage and injection of production chemicals has been studied by operators and oil field service (OFS) companies with several papers having been published. Due to the unique characteristics of DRA, no other units reviewed would be capable of DRA delivery. Case studies show proper DRA applications can generate significant production rate increases, extend tie-back distance, and/or reduce flowline diameters without the need for pumps, and provide optionality to oil companies with respect to receiving tie-back hubs.

How DRA enhances production

The greatest benefit DRAs bring to subsea production lines is the ability to immediately increase production by increasing pipeline capacity. DRAs reduce the drag or frictional pressure drop on the interior pipeline wall. Typically, in a production well, there are two type of driving forces for hydrocarbon production. First is the formation pressure that supplies the driving force for the production. The second is a pump placed at the bottom of the well to help pump out the hydrocarbons that accumulate at the bottom of the well. Typically, in a subsea situation, the wells produce hydrocarbons via formation pressure. The hydrocarbon fluids flow from the wellhead via production lines to a central manifold where the production is gathered into a trunk line to be shipped to a production platform, FPSO, or to onshore directly. By reducing the friction pressure in the individual production lines, or in the trunk lines, DRA can convert more of the available wellhead pressure to enhance the flow rates.

DRAs are long chain, ultra-high molecular weight polymers that reduce the level of turbulence in fluid streams. Typical molecular weights for drag reducing polymers are greater than 5 million. Using parts per million (ppm) concentration levels in the fluid stream, drag reducing polymers interact with the fluid molecules which reduce the formation and propagation of turbulent eddies. This decreases deviations in velocity relative to the bulk flow of the fluid which causes the hydraulic energy to be more focused on moving the fluid stream down the pipeline rather than in a chaotic, random motion. These reduced frictional pressure losses enable pipeline operators to lower operating pressures or increase the rate of fluid flow. The mechanism of drag reduction has been extensively studied and reported in literature (1). A summary of this phenomenon is illustrated in Figure 1.

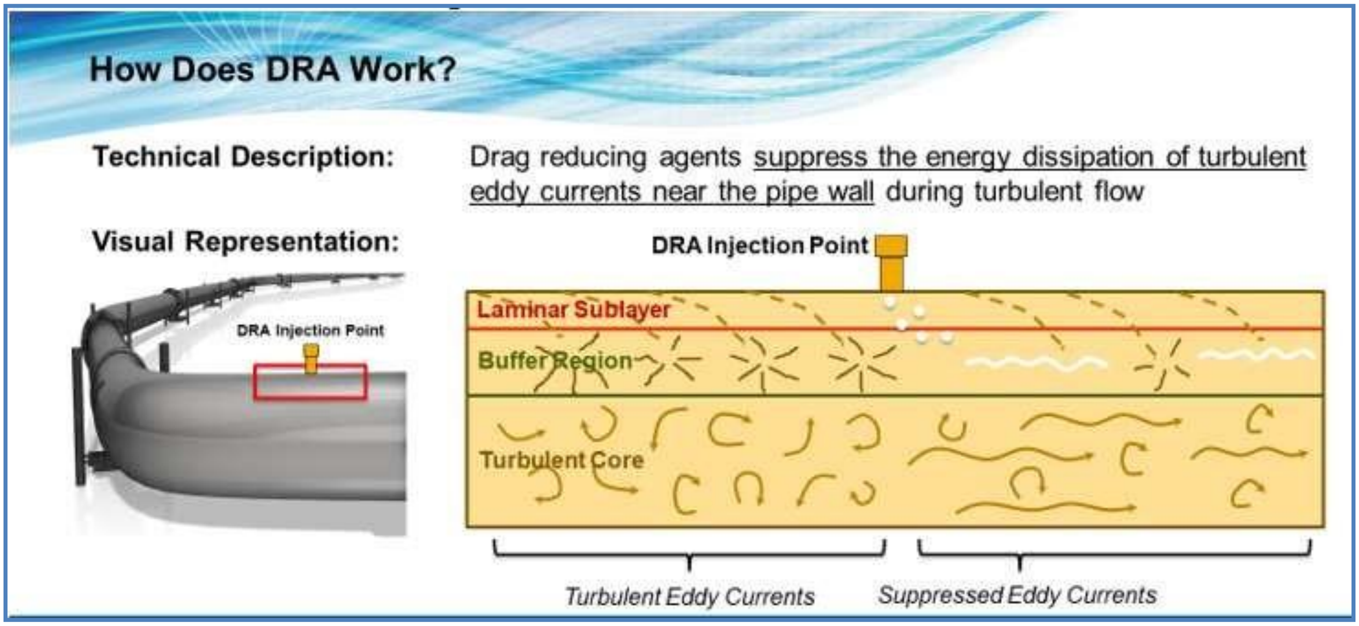

Figure 1, DRA suppresses turbulence, reducing frictional pressure loss along the flowline

In field applications in turbulent flow, DRAs are used to address flow constraints, pressure limitations, or energy demand reductions.

In addition to increasing production by debottlenecking the production line, DRA can provide offshore operators additional benefits:

- Reduce the capital cost associated with a larger diameter pipeline
- DRA injection units are portable (unlike steel pipe)
- DRA can be used for early flush oil and upside production
- Subsea injection can help with topside space limitations
- DRA can be used to add wells to an existing flow line
- DRA can be used to increase tie-back distances
- DRA can be used to maintain flow on pressure de-rated pipelines

Unique DRA characteristics

Different DRAs are designed for specific applications and hydrocarbon types. The DRA designed for this application was created specifically for the subsea applications, particularly multiphase applications located in environmentally sensitive areas.

As mentioned before, DRA is a high molecular weight hydrocarbon polymer. As the name indicates, the polymer is made of only carbon and hydrogen atoms. Refinery impact studies show that hydrocarbons treated with DRA have no adverse impact on the quality of the hydrocarbons (2). The treated hydrocarbon has also been studied for corrosivity impact and has found no change in the corrosive nature of the treated fluid (3).

DRAs are used in onshore and offshore export lines. To date, DRAs have not been successfully used in subsea production lines due to the lack of subsea DRA injection units and DRA's limitation in umbilical lines. For over 15 years, DRAs have been continually modified and tested for umbilical use without success. DRAs contain solid particles (polymer) which are problematic with long umbilical lines as the solids will coat the internal wall and eventually plug the umbilical. Furthermore, DRAs require a dedicated, clean umbilical which are not always available. Subsea injection units offer DRA an immediate alternative to the umbilical challenges.

Performance expectations

- A high DRA injection rate in a single-phase application may achieve 85% drag reduction and could double the flowrate
- A good multiphase application (some gas and water content) may achieve 35% drag reduction. The flowrate increase is dependent on the well's productivity index
- A multiphase application in slug flow should expect good drag reduction results and a potential secondary benefit of decreasing the pressure volatility of the slug flow
- An application with 60% or more water or stratified flow is unlikely to achieve any drag reduction
- DRA can be a cost-effective alternative to increase production without drilling expensive wells

<u>Case study</u>

While DRA has not previously been injected through a subsea injection unit, it has been injected in many multiphase applications. A previously published paper describes an example of a multiphase flow application (4). The figures below describe a case study on a platform-to-platform multiphase application. This case study is extrapolated into a subsea DRA injection for illustrations purposes:

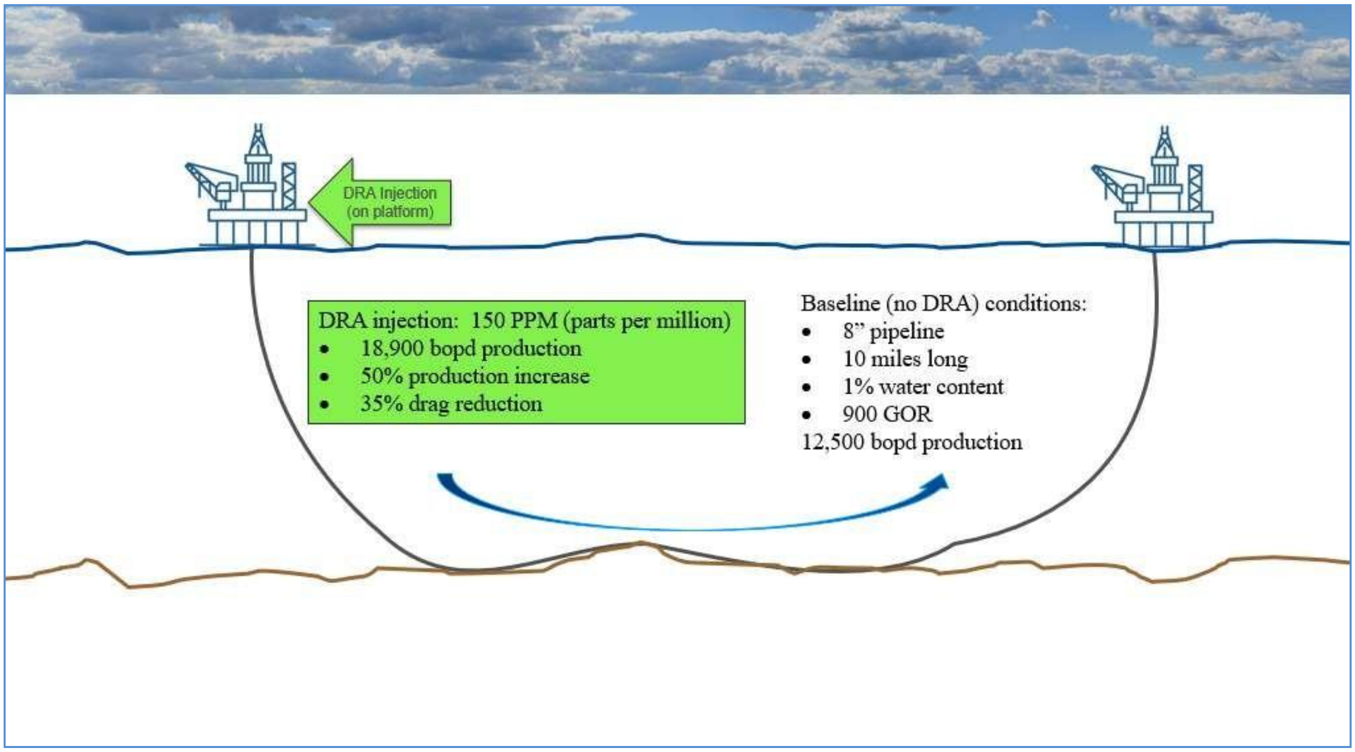

Figure 2, Platform-to-platform multiphase application case study

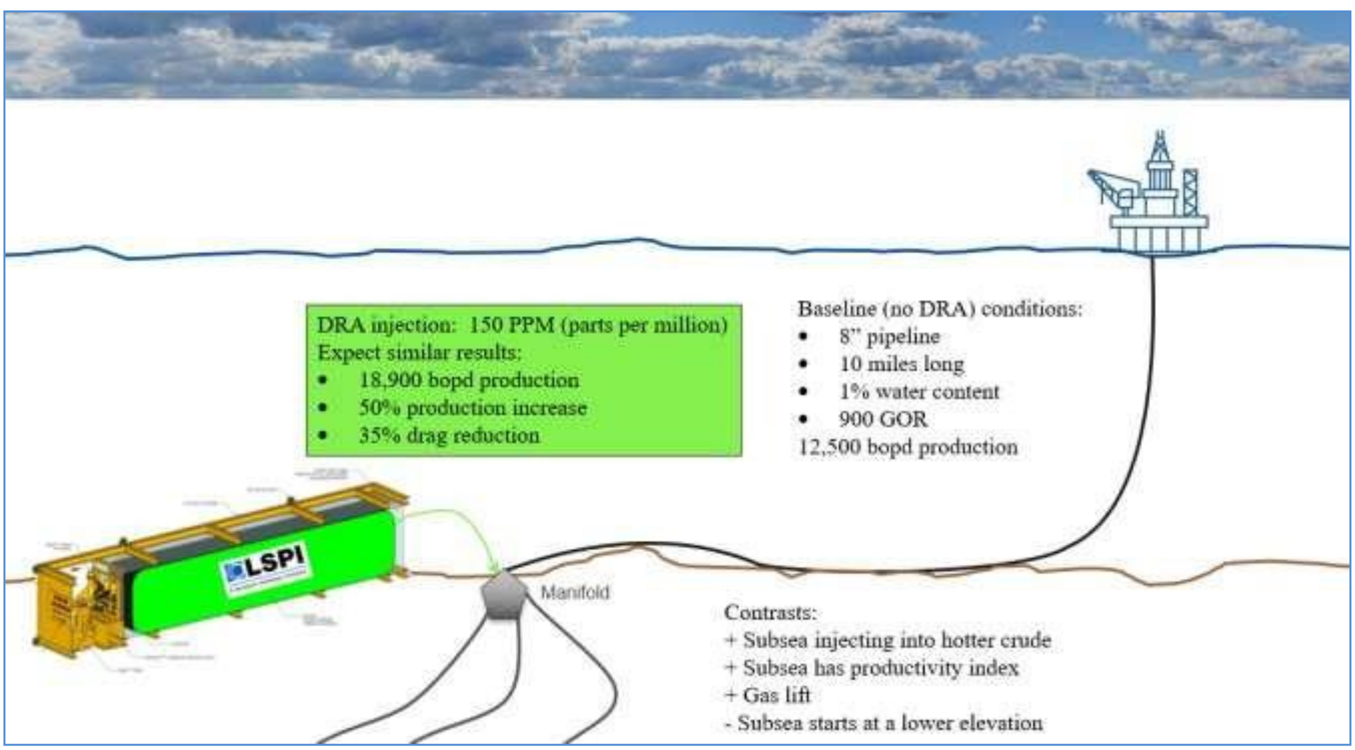

Figure 3, Extrapolated subsea DRA injection

Subsea DRA Characteristics

A DRA designed specifically for the subsea market was developed with the following characteristics:

- A low freezing-point (14ºF / -10C)
- High shear stability (multiphase flow)
- High product stability (remote storage)
- Excellent safety and environmental ratings (non-flammable, non-hazardous):

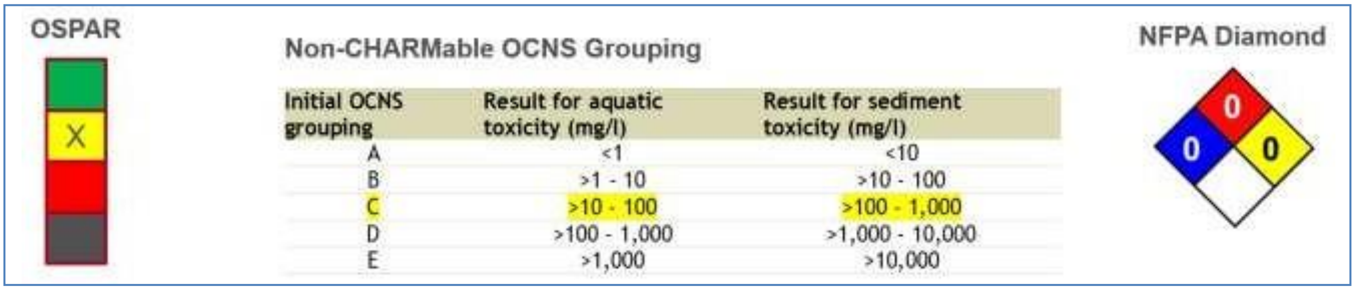

Figure 4, Regulatory ratings

- The Offshore Chemical Notification Scheme (OCNS) applies to chemicals that are intended for use and discharge in the exploration, exploitation and associated offshore processing of petroleum in the UK and Netherlands.
- OSPAR is so named because of the original Oslo and Paris Conventions ("OS" for Oslo and "PAR" for Paris).
- OSPAR is the mechanism by which 15 Governments & the EU cooperate to protect the marine environment of the North-East Atlantic.
  OSPAR started in 1972 with the Oslo Convention against dumping and was broadened to cover land-based sources of marine pollution and the offshore industry by the Paris Convention of 1974. These two conventions were unified, up-dated and extended by the 1992 OSPAR Convention. The new annex on biodiversity and ecosystems was adopted in 1998 to cover non-polluting human activities that can adversely affect the sea.

NFPA Hazard Identification System

The National Fire Protection Association (NFPA) developed a hazard identification system for emergency responders. **Note:** The numbering system in the NFPA Hazard Identification System and the numbering system in the GHS are opposite; higher values in the NFPA system indicate higher hazards, and the opposite is true for the GHS. It must be understood that the NFPA system was designed to convey safety information to emergency first responders, such as fire fighters.

BLUE Diamond Health Hazard	**RED Diamond Fire Hazard (Flash Point)**	**YELLOW Diamond Reactivity**	**WHITE Diamond Special Hazard**
4 Deadly **3** Extreme Danger **2** Hazardous **1** Slightly Hazardous **0** Normal Material	**4** Below 73 °F **3** Below 100 °F **2** Above 100 °F Not Exceeding 200 °F **1** Above 200 °F **0** Will Not Burn	**4** May Detonate **3** Shock and Heat; May Detonate **2** Violent Chemical Change **1** Unstable if Heated **0** Stable	**ACID** – Acid **ALK** – Alkali **COR** – Corrosive **OXY** – Oxidizer – Radioactive **W** – Use No Water

Figure 5, The National Fire Protection Association (NFPA) ratings

Subsea equipment

Technical overview

The 200 BBL unit is designed with the footprint of a standard 40-foot International Standards Organization (ISO) shipping container. The unit without chemical load is non-permit, road transportable, considerably simplifying and lowering logistical costs. The unit is installable with a conventional offshore Multi-Service Vessel (MSV). The in-air weight of the 200 BBL unit loaded is approximately 70 short tons. The unit is designed and certified to DnV 2.7-3 for placement on either a mudmat or suction pile, depending upon seafloor conditions. The unit features dual barrier chemical containment and is pressure compensated and rated to 10,000 feet of salt water (FSW). Also featured is an all-electric design with the advantages of avoiding a separate hydraulic system and the opportunity to use advanced monitoring for determining the health-condition status of pumps, valves and other components. A summary of the specs is outlined in Figure 7 below.

Injection unit specs

Component	Description	Reference/standard
Overall system	• Patent issued dual barrier chemical containment • Qualified to 10,000 fsw / 10-year design life	Meets IMDG requirements (non-hazardous chemical)
Frame	• 40’ x 8’ x 8.5’(tall) • Weight: 64,000 Kg, (tare)	DnV 2.7-3
Storage tank	• 200 bbl (w/ 20 bbl reserve)	ASME, Sect VIII Div. 1
Bladder	• 200 bbl	Mil spec MIL-PRF-32233
Pump	• Modified triplex pump (onshore proven) • Injection pressure differentials of up to 10,000 psi (with 15,000 psi still in qualification) • Electric driven, variable speed controlled	Custom, based on API RP 14 C
Valves & actuators	• Electric motor valve actuators, w/ battery back-up. • Smart Batteries for fail-to-close position	Safety Integrity Level (SIL)2 per IEC 61508
Controls & sensor	• Electronics; 1 Atmosphere cans (3)	API RP 17 F compliant & various IEEE
Piping	• Various sizes, SS w/ Swagelok fittings • Flexible flying leads, rated to 20ksi	API RP-1111 section 2.1.7 (c) Welding: API Specification 17D

Figure 7, Unit specifications

Qualification process

Earlier reported work (Schroeder, 2018) detailed the process of gathering operator input and oil field service (OFS) vessel specifications/constraints regarding seafloor delivery/recovery of the Unit. With industry needs understood and documented, global regulations were reviewed, and selection was made of the best ‘fit for purpose’ standards and recommendations. From this point a design was developed and requirements were documented in a set of functional design specifications (FDS). Iterated during this phase were a series of qualitative risks assessments (QRA) and Failure Mode, Effects and Criticality Analysis (FMECA) to identify risk and then either eliminate or mitigate to an acceptable level. The design and risk assessment considered the full life cycle of the unit through the following operational phases.

- Pre-commissioning of controls on host facility
- Transport unit to quayside
- Quayside preparation of unit
- Transport unit to offshore site
- Prepare unit on MSV
- Install unit on seabed and complete commissioning with handover to host facility
- Operations (on seabed)
- Recover unit from seabed to MSV
- Transport unit to quayside
- Quayside refill / inspection / test

The next major step was developing an inspection and test quality plan (ITP), see Figure 8.

Activity	Description	Quality Related Activity	Reference Document	Acceptance Criteria	Verifying Document
12.	Post Weld NDE	Perform: MP PT UT RT	NDE Procedures Visual Examination NDE Personnel Qualification Records	AWS D1.1 AWS D1.6 ASNT-TC-1A ASME B31.3	NDE Test Report NDE Personnel Qualification Records
13.	Dimensional Checks	Perform Dimensional Checks and Review of Markings	Detail Drawings	Detail Drawings	Dimensional Check Form: Quality Inspection Report
14.	Coating	Submission of Coating Procedure	SOS-QWI-ENG-740-02	SOS-QWI-ENG-740-02	Vendor Certificate of Conformance (Inspection Report)
15.	Assembly	Assemble all Equipment	Seanic Drawings	Seanic Drawings	Seanic Drawings
16.	Prototype Qualification Test	Perform PQT	PQT's 14885-1355543 14913-1296625 16115-1387887 16087-1405866 16087-1413433 16087-1447537 16087-1447739	Approved Procedure	PQT Reports 14885-1355543-1 14913-1296625-1 16115-1387887-1 16087-1405866-1 16087-1413433-1 16087-1447537-1 16087-1447739-1

Figure 8, Inspection and Test Quality Plan (ITP), 4 of 20 activities

Significant efforts were spent engineering, analyzing and testing various bladder designs and manifold arrangements considering a number of factors such as:

- Bladder multiples
- Dual barrier feature and overall constructability
- Material characteristics
- Inspection, Maintenance and Repair (IMR)
- Replacement
- Abrasion of bladder and containment
- Operational sensors/instrumentation interfaces
- Fill / depletion manifolding requirement
- API and military recommended practices and specifications

Bladders

Earlier reported work (Schroeder, 2018) which included input from various engineered fabric manufacturers, testing organizations, operators and regulatory personnel led to development of a bladder fabric / chemical exposure qualification program. Various fabrics were then obtained from top contention manufacturers and then matched with DRA products and put through the testing program, principally examining chemical compatibility and operational life expectancy. Exposure tests were conducted over several time periods and then samples were put through a series of tests to determine fit for purpose life expectancy (Figure 9). An independent third-party lab then conducted and documented the qualification details. Figure 10, bladder demonstration day.

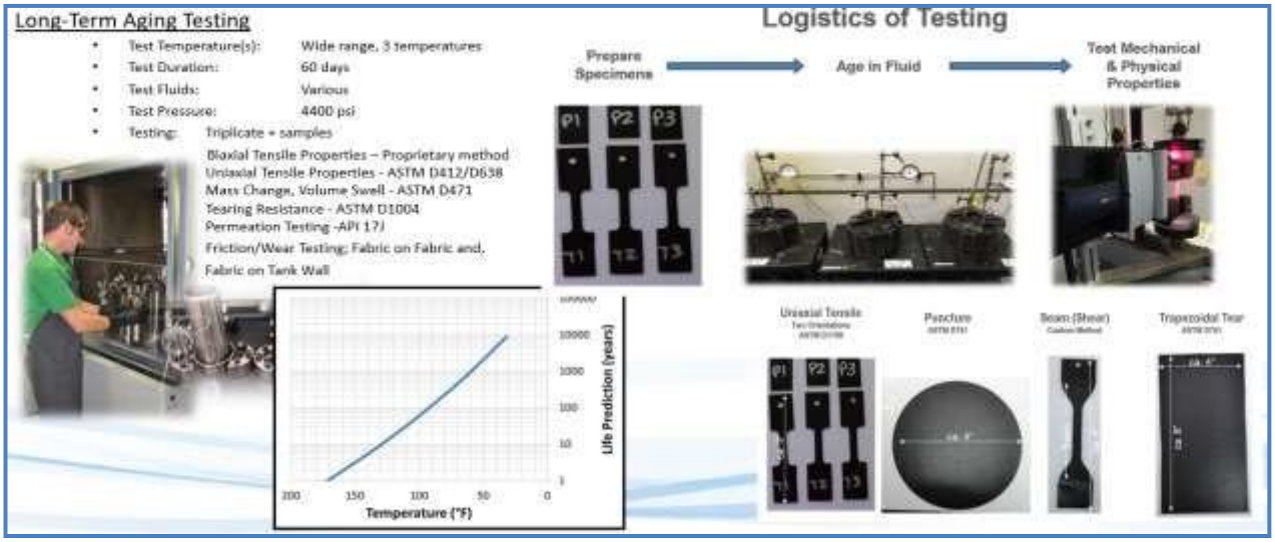

Figure 9, Engineered fabric bladders - chemical testing

Figure 10, Demonstration of bladder storage system (500-gallon scale)

Components and subassemblies

In general COTS components fit for purpose were purchased and assembled into sub-assemblies, then subjected to qualification tests. The sub-assemblies where then combined into the Process Module and Storage Unit which have also been qualified. Currently a dry factory acceptance test (FAT) is being conducted, following which will be a full SIT, first on the deck (dry), then fully submerged in a test pool, see Figure 11.

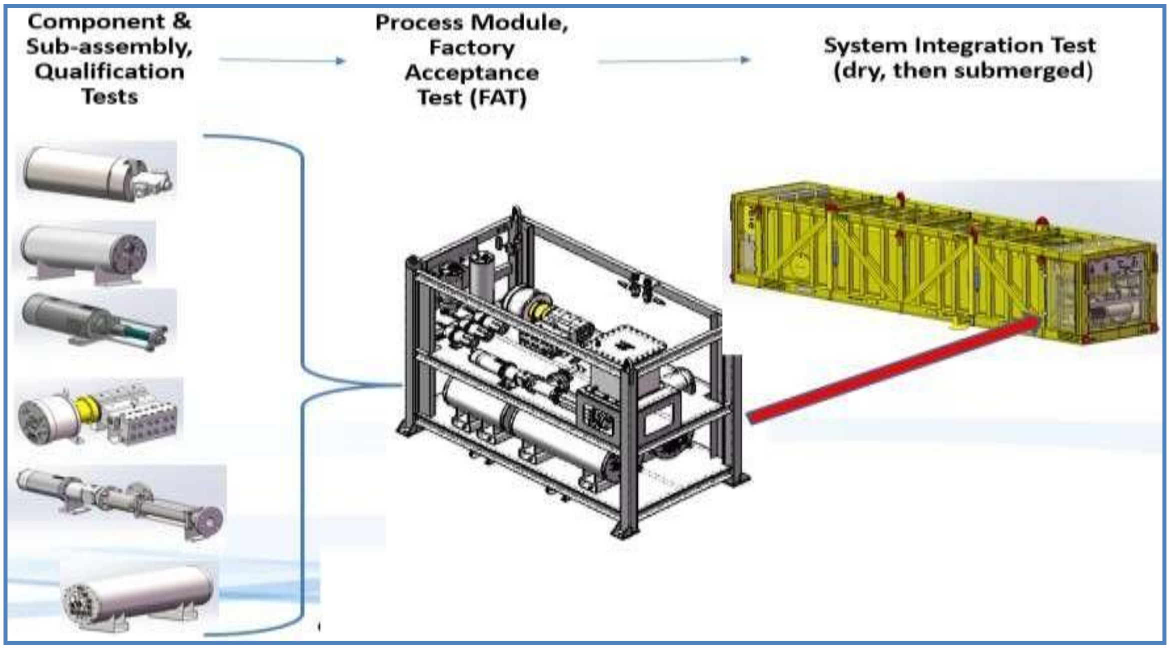

Figure 11, Qualification process

Electric control system

Sensors

The unit incorporates a number of sensors and monitoring devices throughout. While most are common off the shelf, the adaptation of them to meet the unit's needs are in some cases novel and innovative and are being treated as trade secrets.

Electrical Modules / Major Components

- Wet mate electric flying leads (EFL) connectors
- Electric actuator controllers w/ 1 ATM Bottles
- Electric motor controllers w/ 1 ATM Bottles
- Subsea battery module
- Power regulator and control module (PRCM)

All electric valve controller

Utilizing the same design principles and architecture as outlined above and applied on the chemical injection pump, 'smart' all electric controllers with battery backup for a fail to desired position in case of primary power supply disruption is utilized throughout the unit. See Figure 12. For more details on the controller and its qualification, see reference (York, 2019).

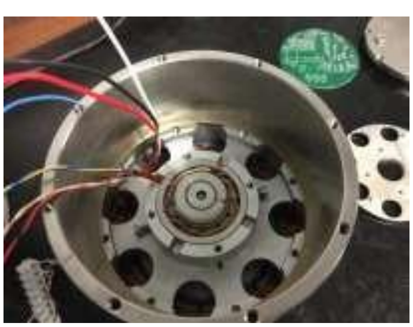

Figure 12, Electric controller internals and with gear drive attached for use as valve actuator.

Figure 13, Electronics, and sensors being qualified

Figure 14, Power Regulation & Control Module

Production module components

Figure 15, Modified triplex injection pump

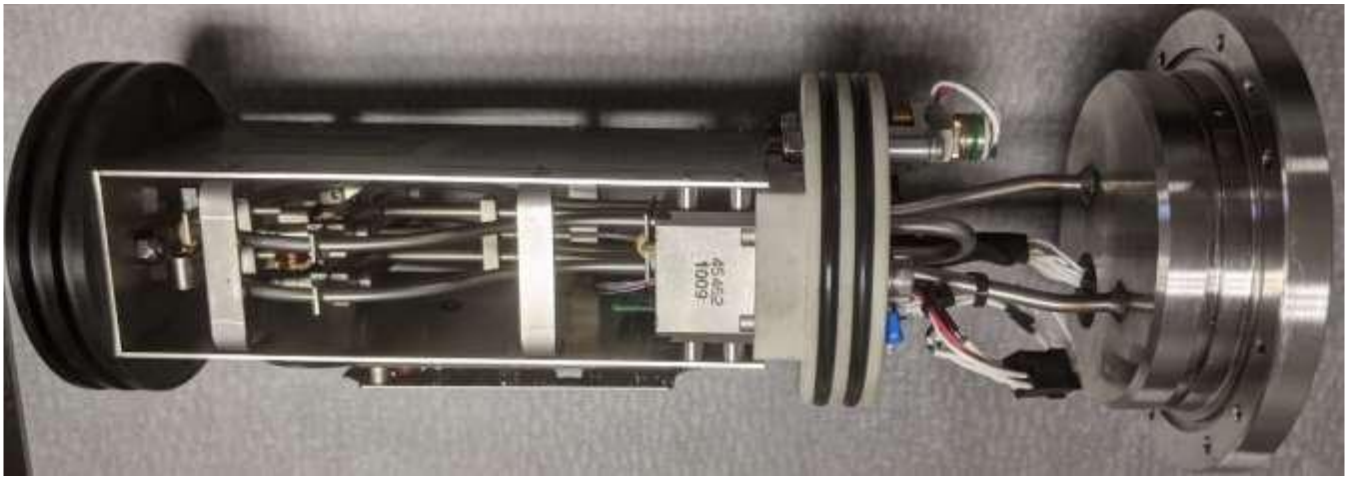

Figure 16, Flow meter

FAT and SIT, work in progress

The FAT and SIT work is being conducted in Houston, Texas, at a well-equipped facility which featured a test pool measuring 50ft. x 50 ft. x 30 ft. deep. See Figure 17. Figure 18 shows the tank ‘lid’ being put in place for the pressure test. Figure 19 shows tank holding pressure and Figure 20 the DnV certification plate. Figure 21 lists the various documents and reports that detail the results to date.

Figure 17, Assemble and test facility

Figure 18, Lid of storage tank being attached for pressure test.

Figure 19, Steel tank pressure testing

Figure 20, DnV certification

Description	**Reference Doc #**
Actuator FDS	14885-1287021
Actuator General Assembly	14885-1296224
Actuator PQT (Incl. Results)	14885-1355543
DRA Injection Pump Motor PQT Results	14913-1296625
DRA Injection Pump Motor General Assembly	14913-1296982
Pump Drive Motor - FDS	14913-1362013
DRA Transfer Pump - FDS	16087-1287021
Process Schematic (P&ID)	16087-1381594
DRA Injection Pump General Assembly	16087-1387314
DRA Transfer Pump & Drive Motor Assembly Drawing	16087-1398286
Project/System Inspection Test Plan (ITP)	16087-1400704
DRA Transfer Pump General Assembly	16087-1403829
DRA Transfer Pump Assembly PQT	16087-1405866
DRA Transfer Pump Assembly PQT Report	16087-1405866-1

Block Diagram - Control System	16087-1412220
Functional Design Specifications (FDS) - Control System	16087-1412305
Functional Design Specifications (FDS) - Software	16087-1412308
Structural Module Functional Design Specification (FDS)	16087-1412509
DRA Storage PQT	16087-1413433
DRA Storage PQT Report	16087-1413433-1
Structural ITP	16087-1422993
Process Module FMECA	16087-1429525
System Level FDS	16087-1435494
DRA Feed Pump Assembly Drawing	16087-1439531
Structural FMECA	16087-1441644
Feed Pump Motor Assembly Drawing	16087-1443325
Weldment, Tank Structure	16087-1445095
Qualitative Risk Assessment	16087-1445130
Weldment, Lid	16087-1446690
DRA Feed Pump PQT	16087-1447537
DRA Feed Pump PQT Results	16087-1447537-1
Coriolis Meter PQT	16087-1447739
Failure Mode, Effects, and Critical Analysis (FMECA) - Software	16087-1448140
Interconnect Drawing	16087-1448154
Safe-Stor 200 DRA Unit General Assembly Drawing	16087-1449509
Chemical Storage Bladders FDS	16087-1450089
Process Module General Assembly	16087-1464527
System Operations & Maintenance Manual (OMM)	16087-1474258
Safe-Stor 200 DRA Unit General Arrangement	16087-1474555
Coriolis Meter General Assembly	16087-1476494
Process Module FAT Procedure	16087-1477749
System Integration Test (SIT)	16087-1479715
DRA Feed Pump FAT	16087-1492428
DRA Transfer Pump FAT	16087-1492429
Actuator FAT	16087-1492430
DRA Injection Pump FAT	16087-1492431
Coriolis Meter FAT	16087-1492433
DRA Injection Pump PQT	16115-1387887
DRA Injection Pump PQT Report	16115-1387887-1
Failure Mode, Effects, and Critical Analysis (FMECA) - Control System	16807-1448135
Coating Procedure	SOS-QWI-ENG-740-02

Figure 21, Documentation and reports

Deploy, recover and service equipment

Service Approach

To provide a reliable and cost-efficient deployment of DRA, it is foreseen that a turnkey service would be provided to clients. Included in the service would be predeployment engineering, landing zone placement, Injection Flying Lead (IFL) and Electric Flying Lead (EFL) routing and client support of control system integration. The deployment and recovery of the DRA unit(s) will be standard operation and include robust lifting points (certified to DnV 2.7-3) along with standard lift rigging.

Figure 22, Offshore Lift

The DRA subsea injection units are a standard size and modular. Therefore, the number of DRA units required at a drill center will be determined based on service frequency and injection rates required to produce the best production increases at a reasonable cost. The DRA units may be remotely monitored and controlled to ensure the client obtains the best cost / production ratio. High reliability and uptime are provided via remote monitoring and online technical support.

When DRA needs replenishing, a replacement plan will be executed in agreement with the client. Where possible, this will be scheduled with other offshore activities so that the replacement is done as a “fly-by” to avoid vessel mobilization costs. The replacement DRA unit will be deployed and connected prior to recovery of the empty unit. Isolation procedures will be executed in coordination with the production facility in strict accordance with the permitting processes to ensure safe execution with no production downtime.

The empty DRA unit will be transported to a service and storage site where it will be inspected, refurbished, and refilled so that it is ready to be re-deployed.

Conclusion

DRA has been successfully proven in offshore and onshore applications over the past four decades. DRA is primarily used to increase flowrates and decrease pipeline pressures. By reducing frictional pressure loss, entire pipeline pump stations have been eliminated in existing systems, or never built in newer systems. DRA is often used to maintain throughput while reducing the operational pressure in de-rated pipelines. The presented patented solutions will soon deliver these same benefits to operators with subsea wells down to 10,000 fsw across the globe.

Subsea application of DRA;

- DRA has been extensively used in the petroleum industry for decades
- Applicable where plateau production is flowline limited
- Significant increase in production rates possible depending on wellstream properties and facility configuration
- Effectiveness of DRA may be assessed and analyzed in advance to predict effectiveness
- DRA effectiveness may be simulated and tested at lab scale
- DRA effectiveness may be validated with temporary subsea injection via ROV
- If the injection unit were to shut down or stop injection, production reverts to pre-injection levels.
- Unit is pressure compensated and may be re-deployed to other locations as well pressures naturally decline

Acknowledgments

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List of Abbreviations

BBL	Barrel
BOE	Barrels of Oil Equivalent
CAPEX	Capital Expenditure
COTS	Common Off the Shelf
DFMECA	Design, Failure Mode, Effects and Criticality Analysis
DOE	(United States) Department of Energy
DRA	Drag reduction agent
EIA	Energy Information Agency
EFL	Electric flying leads
FAT	Factory acceptance test
FDS	Functional Design Specifications
FMECA	Failure Mode, Effects and Criticality Analysis

FSW	Feet saltwater
GPD	Gallons per day
HAZID	Hazard and risk analysis
HAZOPS	Hazard and operability study
IFL	Injection Flying Lead
ITP	Inspection and Test Quality Plan
JSA	Job Safety Analysis
KW	Kilowatt
MSV	Multi-service vessel
NNM	Not Normally Manned
NDE	Non-Destructive Examination
OPEX	Operating expenditure
PQT	Prototype Qualification Test
PRCM	Power Regulation & Control Module
QA/QC	Quality assurance/quality control
QRA	Qualitative Risk Assessments
RAM	Reliability, Availability, and Maintainability
RPSEA	Research Partnership to Secure Energy for America
SIT	System Integration Test
SME	Subject Matter Experts
QRA	Qualitative Risk Assessments
USD	United States Dollar

List of Figures

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(3) LSPI Technical Bulletin 85

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