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GP 78-08

Design and Installation of Deepwater Pipelines and Flowlines

Group Practice

**BP GROUP
ENGINEERING TECHNICAL PRACTICES**

Foreword

This is the second issue of Engineering Technical Practice (ETP) GP 78-08.

This Group Practice (GP) is not a standalone document but is part of a larger suite of ETPs that defines BP approach to offshore pipeline design and construction.

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1. Scope

- a. This GP provides requirements for complex engineering issues and challenges affecting design and installation of subsea pipelines and flowlines (especially deepwater) for transporting gas and liquid hydrocarbons and water.
- b. This GP does not cover umbilicals, subsea facilities, controls, or flexible pipes, but it does provide reference to applicable riser GPs.
- c. This GP is to be used with other category 78 ETPs for subsea applications necessary to undertake and execute subsea projects.
- d. This GP is to be used with series 43 ETPs for pipelines, specifically GP 43-21.

2. Normative references

The following referenced documents may, to the extent specified in subsequent clauses and normative annexes, be required for full compliance with this GP:

- For dated references, only the edition cited applies.
- For undated references, the latest edition (including any amendments) applies.

BP

GIS 30-801	Design and Engineering of Logic Solvers.
GIS 43-213	Pipeline Spanning (DNV RP F105)
GIS 43-311	Manufacture of Longitudinal or Helical Seam Submerged Arc Welded Linepipe in Grades up to X80
GIS 43-312	Manufacture of High Frequency Induction (HFI) or Electric Resistance Welded (ERW) Linepipe in Grades up to X70
GIS 43-313	Manufacture of Seamless Linepipe in Grades up to X80
GIS 43-314	Manufacture of 13% Chromium Seamless Linepipe
GIS 43-315	Manufacture of 22% and 25% Chromium Duplex Stainless Steel Seamless Linepipe
GIS 43-316	Manufacture of CRA Clad or Lined Steel Pipe.
GIS 43-317	Carbon Steel Induction Bends for Pipelines in Grades up to X80 - Supplement to ISO 15590-1:2001
GIS 43-318	Carbon Steel Fittings for Pipelines in Grades up to X80 - Supplement to ISO 15590-2:2003
GIS 43-319	Carbon Steel Flanges for Pipelines in Grades up to X80 - Supplement to ISO 15590-3:2004
GIS 43-339	Automated Ultrasonic Testing of Pipeline Girth Welds
GIS 43-352	EN ISO 14723 Subsea Pipeline Valves.
GP 06-14	Erosion Control.
GP 06-20	Materials for Sour Service.
GP 06-29	Corrosion Protection During Hydrotesting.
GP 06-40	Pipeline Coating Selection
GP 30-75	Management of the Safety Lifecycle.
GP 30-76	Development of the Process Requirements Specification.



GP 30-80	Implementation of the Process Requirements Specification.
GP 30-81	Operation and Maintenance.
GP 43-04	QA/QC.
GP 43-09	Hydraulic Design of Pipeline Systems.
GP 43-21	Offshore Pipeline System Design and Construction.
GP 43-26	Offshore Surveys.
GP 43-30	Offshore Pipeline Geotechnical Surveys.
GP 43-31	Linepipe Procurement.
GP 43-32	Pipe Handling Logistics.
GP 43-33	Welding of Pipelines.
GP 43-35	Valves.
GP 43-36	Pipeline Protection (mitigation measures).
GP 43-37	Control Systems for Pipelines.
GP 43-46	Pipeline Pressure Testing and Precommissioning.
GP 43-49	Pipeline Integrity Management Systems.
GP 43-50	Pigging, Pig Launchers, and Receivers.
GP 43-52	Inspection and Integrity Assessment of Pipeline Systems
GP 43-53	Pipeline Intervention and Repair.
GP 65-72	Riser Vortex Induced Vibration Design Guidelines.
GP 65-75	Flexible Riser Guidelines.
GP 78-03	Achieving Reliability in Subsea Projects.
GP 78-04	Reliability Techniques for Subsea Projects.
GP 78-09	Design Guidelines for Subsea HIPPS.
GP 78-10	Design and Installation Guidelines for Subsea Manifolds.
GP 78-11	Design Guidelines for S/S Chemical Injection at Trees, Jumpers, and Manifolds.
GP 78-12	Design Guidelines for Well Jumper Flowlines.
GP 78-18	Design and Operation of Subsea Production Controls Systems (ISO 13628-6)
GP 78-26	Subsea Reliability and Maintenance Data Collection.
GP 78-28	ROV Selection and Operations.
SAFEBUCK JIP	Safe Design of Pipelines with Lateral Buckling.
S/EPT/072/05	Deepwater Pipelines R&D Program Guidance and associated references.
Strategy Guide	BP Subsea Reliability Strategy, A Guide for BP Leaders.

American Petroleum Institute (API)

API Spec 6A	Specification for Wellhead and Christmas Tree Equipment.
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American Society of Mechanical Engineers (ASME)

ASME B31.3	Process Piping.
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British Standards Institute (BSI)

PD 5500	Specification for unfired fusion welded pressure vessels.
BS 7608	Code of practice for Fatigue design and assessment of steel structures.



BS EN 12201-1 Plastic piping systems for water supply - Polyethylene - Part 1: General.

Det Norske Veritas (DNV)

DNV-OS-F101 Submarine Pipeline Systems.
 DNV-RP-C203 Fatigue Design of Offshore Steel Structures
 DNV-RP-F105 Free Spanning Pipelines.
 DNV-RP-F110 Global Buckling. (Same as DNV Report 2001-0142.)

International Electrotechnical Commission (IEC)

IEC 61508 Functional safety of electrical/electronic/programmable electronic safety-related systems.
 IEC 61511 Functional safety - Safety instrumented systems for the process industry sector.

International Organization for Standardization (ISO)

ISO 3183 Petroleum and Natural Gas Industries - Steel Pipe for Pipeline Transportation Systems
 ISO 15590 Petroleum and Natural Gas Industries - Induction Bends, Fittings and Flanges for Pipeline Transportation Systems

3. Terms and definitions

For the purposes of this GP, the following terms and definitions apply:

Deepwater

Water depth greater than 305 m (1000 ft). Various definitions of deepwater have been proposed. The 305 m (1000 ft) definition was developed by U.S. Minerals Management Service (MMS). The definition of “deepwater” is not used rigorously in this GP. References to deepwater pipelines may also be applicable for pipelines in water depth less than 305 m (1000 ft).

Design pressure

Pressure selected as maximum sustained pressure exerted by pipeline contents to which the pipeline is designed.

Expected operating life

Period of time selected for the purpose of verifying that a replaceable or permanent component is suitable for anticipated service.

Export line

Pipeline that transports normally processed oil and gas fluids between offshore platforms or between offshore platform and shore facility.

Flowline

Rigid or flexible pipeline that transports unprocessed fluids from wellhead to first downstream process or collector component.

Injection line

Rigid or flexible pipeline that directs processed liquids or gases into formation, wellhead, or riser to support hydrocarbon production activity.



Offshore pipeline

Piping that transports fluids between offshore production facilities or between platform and shore facility. Pipelines may be classified into three categories: flowlines, injection lines, and export lines. "Pipeline" in this GP applies to all three categories.

Pipeline

Installation through which fluids or gases are conveyed, including pipe, pig trap, components, and appurtenances, up to and including isolation valves at boundary limits.

Pipeline system

Pipelines, including flow control, metering, tanks, pumping and compression, control and data acquisition, communications, and associated buildings.

4. Symbols and abbreviations

For the purpose of this GP, the following symbols and abbreviations apply:

1oo2	1 out of 2.
2oo3	2 out of 3.
2oo4	2 out of 4.
AA	Anti-agglomerant.
AC	Alternating current.
ADCP	Acoustic Doppler current profiler.
AUV	Autonomous underwater vehicle.
A&R	Abandonment and recovery.
BAT	Buckling assessment tool.
BCT	Buckling costing tool.
BOD	Basis of design.
CAPEX	Capital expense.
CP	Cathodic protection.
CRA	Corrosion resistant alloy.
C-Mn	Carbon manganese.
DC	Direct current.
DEH	Direct electrical heating.
DP	Dynamic positioning.
DPIS	Double Pipe Insulated System



DRA	Drag reducing agent.
DWRUPE	Deepwater response to underwater pipeline emergency.
EA	Engineering authority.
ECA	Engineering criticality analysis.
ETAP	Eastern Trough Area Project (BP field).
FBE	Fusion bonded epoxy.
FEA	Finite element analysis.
FEED	Front end engineering design.
GOM	Gulf of Mexico.
GSPU	Glass syntactic polyurethane.
HAİN	High accuracy inertial navigation.
HFI	High frequency induction.
HIPPS	High integrity pressure protection system.
HPHT	High pressure high temperature.
HT	High temperature.
ILI	Inline inspection.
ILS	Inline sled.
IM	Integrity management.
IPB	Integrated production bundle.
IR	Infrared.
JIP	Joint industry project.
KHI	Kinetic hydrate inhibitor.
LBL	Long baseline.
LDHI	Low dosage hydrate inhibitor.
MDPT	Multidiameter pigging tool.
MEG	Monoethylene glycol.
MFL	Magnetic flux leakage.
NDE	Nondestructive examination.



NDT	Nondestructive testing.
NPV	Net present value.
OHTC	Overall heat transfer coefficient.
OPEX	Operational expense
PE	Polyethylene.
PFD	Probability of failure on demand.
PIMS	Pipeline integrity management system.
PIP	Pipe in pipe.
PLEM	Pipeline end manifold.
PLET	Pipeline end termination.
PP	Polypropylene.
PU	Polyurethane.
PUF	Polyurethane foam.
QC	Quality control.
QM	Quality management.
R&D	Research and development.
ROV	Remotely operated vehicle.
Sa	Statistical average roughness.
SAAM	Smart acquisition analysis module.
SCR	Steel catenary riser.
SECT	Skin effect current tracing.
SIL	Safety integrity level.
SJC	Single Joint Connector
SSCV	Semisubmersible crane vessel.
STP	Site technical practice.
S-N	Stress curve.
TA	Technical authority.
TDP	Touchdown point.



TRB	Three roll bending (pipe fabrication process).
UO	U-ing and O-ing (pipe fabrication process).
UOE	U-ing, O-ing, and expanding (pipe fabrication process).
UTS	Ultimate tensile strength.
UV	Ultraviolet.
VAS	Virtual anchor spacing.
VBA	Visual Basic application (Microsoft).
WHSIP	Wellhead shut-in pressure.
XHPHT	Extreme high pressure high temperature.

5. Applications

5.1. Pipeline applications

- a. This GP is primarily targeted at more demanding and less conventional subsea pipeline applications, including pipelines that operate in deep water, high pressure and temperature, with corrosive contents, or other challenging process conditions.
- b. Although this GP refers to deepwater pipelines and flowlines, demanding subsea pipeline challenges are not exclusive to deepwater and can also occur in shallow water.

5.2. Engineering application

- a. This GP is applicable to project engineering managers, engineering authorities (EAs), technical authorities (TAs), and project engineering teams.
- b. Information in this GP is grouped by subject, with intent that relevant sections may be used in Site Technical Practices (STPs) and project specifications for deepwater pipeline design and construction.

5.3. Associated documentation

- a. Much information in this GP was obtained through deepwater development programmes, including S/EPT/072/05, its associated project reports, and input from BP engineers with global experience of deepwater projects.
- b. This GP is under “subsea” 78 series rather than “pipeline” 43 series.
- c. This GP should be read in conjunction with 43 series ETPs, especially GP 43-21, which contains requirements for design and installation of conventional pipelines and flowlines.
- d. GP 43-21 refers to requirements for all offshore pipelines, while this GP provides more detailed information and requirements for more technically demanding subsea applications.
- e. This GP refers to specific sections of GP 43-21 as needed.



6. Flow assurance

6.1. General

- a. This clause is applicable to both shallow and deepwater flowlines and should be read in conjunction with GP 43-21.
- b. Deepwater flowlines shall be designed to prevent blockage due to wax, hydrate, sand, or debris.

Blockage can be prevented by regular pigging, line sizing, insulation, flowline heating, or chemical injection. Details are in 6.2 through 6.5.

- c. Deepwater flowlines should be designed to meet the following flow assurance requirements:
 - 1. Provide sufficient pressure at host facility to enable efficient processing.
 - 2. Provide sufficient flowrate to comply with contractual obligations.
 - 3. Avoid formation of stable emulsions.
 - 4. Accurately predict fluid handling requirements to optimise design of slug catchers and associated equipment.
 - 5. Provide sufficient arrival temperature at host facility.

Some compromises may be required to comply with economic design.
- d. Flow assurance design should account for all potential flow regimes, including:
 - 1. Peak to minimum normal operating conditions (flowrate, fluid composition, pressure, and temperature).
 - 2. Shutdown/startup conditions.
 - 3. Blowdown.
 - 4. Flushing operations.
 - 5. Displacement of production fluids during extended shutdowns.
 - 6. Pigging operations.
 - 7. Later life operating condition (possibly with high water cut).
- e. Use of drag reduction additives or internal coatings may be considered to reduce pressure drop along the flowline.

6.2. Hydraulic analysis

- a. Detailed information on hydraulic analysis and tools recommended for assessment is in GP 43-09.

Many software models recommended in GP 43-09 have been developed for pipelines in water depths not typically defined as deepwater and may not consider some deepwater issues. Therefore, verification by the BP multiphase flow team of all deepwater flow assurance results from models is recommended.

- b. If pumps or compressors are required to provide fluid transportation, hydraulic analysis should consider net present value of pipeline diameter versus pumping and compression requirements to obtain the most cost effective solution.
- c. There is potential for slug acceleration in deepwater flowline systems with long risers due to breakout of gas as external pressure reduces. Measures should be taken to decelerate



slugs and to ensure that top bend of riser and topsides piping are able to withstand hydraulic forces and associated increased erosion.

Information on flow induced pulsations along risers is in GN 65-714.

6.3. Insulation

6.3.1. General

- a. Insulation should be considered for:
 1. Reducing temperature gradient along the flowline to ensure delivery temperatures above minimum requirements (e.g., above wax appearance temperature).
 2. Extending cooldown times to allow sufficient time for mitigation before fluids reach conditions where hydrates may form.

Depending on system specifics, either overall heat transfer coefficient (OHTC) or cooldown requirement will dominate insulation design.

6.3.2. Insulation design

- a. Design of the insulation system shall account for both static and dynamic heat transfer.

Static overall heat transfer is a function of flowline system geometry (thicknesses of steel, coating, insulation, and concrete) and individual heat transfer coefficients. Spreadsheets for calculating OHTC for single flowlines and pipe in pipe (PIP) systems are in [RD 78-004](#) and [RD 78-005](#). These OHTC calculation tools are approximate and may be used for conceptual design during appraise, select and define stages. Calculation of riser thermal analysis is contained in GN 65-702.

Joints, flanges, tees, and fittings are more difficult to effectively insulate than flowline sections and often result in cold spots along the flowline.

Flowline burial in soft marine clay soils can provide significant insulation benefit. Burial for insulation may be considered if practical and if cover can be ensured over the expected pipeline design life. Burial can extend cooldown time from 3 days to 4 days, but warmup time is also extended to perhaps 1 days or 2 days. Upheaval buckling may be an issue if flowline burial is used.

- b. OHTC values for insulation system front end engineering design (FEED) and detailed design should be confirmed and/or verified by the insulation Vendor.

GN 36-009 and GN 36-010 provide guidance on the detailed design of insulation systems, and on the materials and system test data which is required from vendors.

Some basic performance data from vendors is included in Annex A.

- c. Axial discontinuities should be taken into account in evaluating insulation effectiveness and often require finite element analysis (FEA) to calculate dynamic heat transfer.
- d. Buoyancy effect of insulation should be accounted for in flowline design calculations.

6.3.3. Anodes

- a. The insulation system should provide for anodes connected to the flowline.

Anode connections may be difficult for reeled pipelines. Protection from attached structures may be necessary.

For pipelines with PLETs, anodes may be installed on PLETs and not on the flowline, provided that the flowline has with high quality corrosion and wet



insulation overlay, and the coverage distance from the PLET is acceptable. This has been done on GOM projects Atlantis NF and Thunderhorse.

- b. Anodes should not be directly connected to pipelines susceptible to hydrogen embrittlement, for example 13% chromium alloys.

Further details are in GN 36-002.

- c. For low alloy steel pipelines, anodes should be clamped to the pipe as half shells with an electrical cable connecting anode to anode pad.
- d. Any heat loss through anodes should be accounted for in the OHTC calculation.

Any heat transfer to the anodes will affect their electrochemical performance. Further guidance is available in ISO 15589-2.

6.3.4. Wet flowline insulation systems

- a. Guidance on wet flowline insulation is in GN 36-009 and GN 36-010.

Requirements for flexible flowline insulation are also covered by this section.

- b. The vendor shall provide a detailed description of the materials and layers within the insulation and field joint.
- c. The insulation vendor should provide the baseline OHTC of the pipe and field joint coating system.
- d. The insulation vendor shall provide the field joint coating procedure for BP approval.
- e. The vendor shall document the following properties:
 - 1. Primary properties: Thermal conductivity; specific heat; hydrostatic strength; ageing resistance; water absorption.
 - 2. Secondary properties: Abrasion; adhesion; bending resistance; bulk modulus; cathodic disbondment; compressive creep; impact resistance; density; fatigue resistance; friction; shear, tensile and compressive properties; thermal expansion; thermal shock resistance; glass transition temperature (T_g) or heat deflection temperature (HDT) of resins; and resistance to biological effects and UV.
- f. The vendor should provide a detailed operating history. This should consist of a project reference list for the coating, including water depth, design temperature and operating temperature.
- g. Acceptance criteria should ensure acceptable insulation properties at end of field life. Minimum acceptable properties should be stated where possible. The vendor should demonstrate heat transfer characteristics at end of field life, e.g. by demonstrating constant properties or slow and predictable decline.
- h. All coating layers should be assumed to absorb water unless justified otherwise.

Insulation vendors often assume that the coating resists water permeation through to the pipe surface, i.e. the coating is assumed to be “wet and cold” at the outer surface and “hot and dry” at the pipe. This assumption may not be valid over the full design life.

- i. System qualification test data shall be available for the insulation system being employed. All tests should be carried out on both pipe coating and field joint, and should include the following:
 - 1. Simulated service test to confirm heat transfer characteristics of system under all expected operational loads.



2. Simulated installation test under all expected installation loads, including survival conditions, e.g. static bend test for reeling, tensioner simulation (also see 18.1).
 3. Cyclic bend test for dynamic applications.
 4. Ring shear test.
 5. Thermal shock tests.
- j. The mechanical and thermal properties of the field joints should match or be comparable to those of the insulation coating. If this is not possible, then the consequences of the variation in field joint properties shall be assessed in detail.

A reduction in field joint mechanical properties may lead to strain concentrations at field joints. A reduction in field joint thermal properties may lead to preferential heat loss at field joints and problems with thermal transients. These effects are undesirable but may be acceptable if quantified and justified through detailed analysis.

- k. Field joints shall be tested to prove that they will not lead to cracking or gaps in insulation.

Recent industry experience with glass syntactic polyurethane (GSPU) field joints has seen failures if application procedures are not rigorously controlled. Solid polypropylene (PP) or polyurethane (PU) field joints reduce risk, but significant attention is required to ensure good bonding with pipe insulation, particularly if field joint is a different material. PP generally gives better performance for pipe coated with PP insulation and reduces the level of process control required offshore but at a cost penalty compared to PU. PU is the preferred field joint coating for GSPU insulation.

6.3.5. PIP insulation systems

- a. PIP insulation should be considered where the insulation requirements go beyond the capabilities of wet coatings.

PIP systems can be described as either “bonded” or “unbonded”.

In a bonded PIP system, insulation material is bonded to both inner and outer pipes e.g. by blowing PU foam into the annulus between the two pipes. The bonding allows axial tension to be applied to outer and inner pipes simultaneously. However, completion of the outer pipe field joint requires half shells to be welded between outer pipe ends. Bonded PIP is usually installed by S-lay to allow multiple work stations for field joint half shell welding.

In an unbonded PIP system, insulation material is bonded to the inner pipe only. Unbonded PIP can be installed by reel-lay, J-lay, or S-lay. For reel-lay, the weight of inner pipe is carried by distribution of tension between inner and outer pipes on the reel. Inner pipe lay tension is lost at the second end when the pipeline is cut ready for laydown. If spacers are used to support the inner pipe within the outer pipe, the requirement for compressive strength of insulation is removed, allowing other insulation materials, such as rockwool, microporous silica or aerogels, to be used. Bulkheads may be inserted within each PIP joint, or occasional PIP joints, to transfer axial load between the two pipes. In this case, unbonded PIP will behave like bonded PIP.

Ideally, bulkhead and spacers will provide structural strength with low heat transfer. These two requirements conflict with each other; design may involve some compromise on each requirement.

PIP systems are often proprietary, EPIC systems due to the interaction between installation and operational requirements.



- b. Guidance on PIP insulation is in GN 36-009 and GN 36-010.
- c. The insulation vendor shall provide a detailed description of the components within the system and field joint, including internal seals to limit the effect of flooding.
- d. The vendor should provide the baseline OHTC of the PIP system.
- e. The vendor shall provide the field jointing procedure for BP approval.
- f. The vendor shall document the following properties:
 - 1. Primary properties: Thermal conductivity; specific heat; ageing resistance.
 - 2. Secondary properties: Bending resistance; compressive creep; density; dimensional stability; shear, tensile and compressive properties; thermal expansion; thermal shock resistance.
- g. The vendor should provide a detailed operating history. This should consist of a project reference list for the PIP system, including water depth, design temperature and operating temperature.
- h. Acceptance criteria should ensure acceptable insulation properties at end of field life. Minimum acceptable properties should be stated where possible. The vendor should demonstrate heat transfer characteristics at end of field life, e.g., by demonstrating constant properties or slow and predictable decline.
- i. System qualification test data shall be available for the insulation system being employed. All tests should be carried out on both pipe coating and field joint, and should include the following:
 - 1. Simulated service test to confirm heat transfer characteristics of system under all expected operational loads.
 - 2. Simulated installation tests for all expected installation loads, including survival conditions, e.g. static bend test for reeling, tensioner simulation (also see 18.1).
 - 3. Cyclic bend test for dynamic applications.
 - 4. Ring shear test.
 - 5. Thermal shock tests.
- j. Many PIP systems are designed to minimise the number of offshore welds and installation time. The structural configuration should be checked carefully to ensure that in-service strength of the field joint detail, including weld fatigue life, is adequate for the pipeline life.

The Texaco Erskine PIP failed in service following cracks at partial penetration welds in the outer pipe field joint. The failure was attributed to design error (cyclic stresses were underestimated), poor workmanship offshore, and greater than expected thermal cycling during early operation. Partial penetration welds were the weak link in the design but could be proven to be acceptable if designed and installed accordingly.

- k. The method for insulating PIP field joints should protect insulation from degradation or fire hazard due to welding of inner and outer pipes.
- l. Where possible, the mechanical and thermal properties of the field joints should match those of the PIP. If this is not possible, then the consequences of the variation in field joint properties shall be assessed in detail.

A reduction in field joint mechanical properties may lead to strain concentrations at field joints. A reduction in field joint thermal properties may lead to preferential heat loss at field joints and problems with thermal transients. These effects are



undesirable but may be acceptable if quantified and justified through detailed analysis.

- m. Patents exist for various PIP concepts, materials, and fabrication methods. Freedom of working should be checked.

6.4. Flowline heating systems

6.4.1. General

- a. Flowline heating systems may be considered (in conjunction with insulation systems) to maintain thermal performance of the flowline system.
- b. Heating systems should be considered as supplemental systems to maintain thermal performance during shutdowns.

Both electrical and hot liquid systems are available. Detailed information on each system is provided in RD 78-006, and is summarised in 6.4.2 through 6.4.5. Not all systems have been used to date; RD 78-006 provides some relevant information for use in a technology readiness level (TRL) assessment.

- c. Direct current (DC) electrical heating systems should not be used because they may lead to localised corrosion.

6.4.2. Hot water heating systems

Hot water systems are generally more controllable than electrical heating systems and may use waste heat from topside processes, such as gas turbine cooling. Hot water systems may also provide continuous heating to the flowline. Currently, two types of hot water heating systems have been used.

- a. Bundle heating system

Hot water flowlines are incorporated into a bundle, with heat transferred through convection in the annular space and conduction through centralisers and radiation. System length is limited by bundle fabrication, typically 7.5 km (4.6 mi) per bundle section. Current applications include Britannia, Asgard, Gullfaks, and Skene, all of which are operating successfully.

- b. PIP loop system

A PIP loop system may only be used with dual PIP systems. Hot water is pumped through the annular space of one flowline and returns along the annular space of the other flowline. Insulation for PIP hot water heating is on the outside of the outer pipe. Therefore, both inner and outer pipes are fully warmed to operating temperatures. This approximately doubles compressive thermal loading on the flowline system and ensures that thermal expansion management is necessary. The only application of this technology is on King where water is heated from turbine waste. This is operating successfully.

6.4.3. Direct electrical heating

Direct electrical heating (DEH) systems use pipe steel as conductors in the electrical circuit. Current in the wall of the flowline generates heat from electrical resistance.

Electrical power for heating may be supplied by platform generators that usually supply pumps and compressors, since these may not be running during shutdown. However, additional transformers may be required to meet electrical heating system voltage requirements.



Two types of direct electrical heating have been used.

a. Open loop DEH system

The electrical circuit is through a power cable running from the near to far end of the flowline, connection between cable and flowline at the far end, and return flow back through the flowline. In the open loop (or grounded) system, the far connection point is effectively grounded to earth and return current flows through pipe and seawater in parallel. The open loop system means that there is no potential difference between the pipe and external environment and no risk of electrical short circuit through the pipe coating. However, there is potential difference between cable and seawater. An electrically insulated cable is required to prevent short-circuit between the cable and seawater.

The system is relatively simple with small number of components that may improve reliability compared to other systems. The system has been installed by Statoil at Asgard, Huldra, Norne Satellites, Tyrihans and Kristen. On Kristin, the operations team use DEH on an average of 1 day/month. The operating experience is not known for the other projects; currently, Statoil do not have a log of how many times the systems have been switched on or cumulative period of operation. Even the oldest system might only have been switched on a handful of times and operated for a few days, compared to the design life of one year cumulative operation.

The system may affect the CP design of the flowline. Corrosion risks may occur from stray currents at locations of coating damage and unmatched pipe magnetic permeabilities. Also, the anode surface area has to be adequate to prevent premature anode consumption.

There is potential electrical interference within 50 m (164 ft) of the flowline. Structures should be bypassed to avoid stray currents. An alternative "closed loop" DEH system has been proposed where the far connection point is not earthed and return circuit is only through the flowline. The closed loop system is more efficient because all return current heats the flowline. However, the system requires 100% guarantee of electrical isolation of flowline from seawater. This is not possible and a closed system of this type has not been implemented on any subsea developments.

b. PIP DEH system

The electrical circuit consists of a loop through inner and outer pipes and a bulkhead at the far end. The power supply is connected across the two pipes. If the power supply is connected at one end, the two pipes require electrical isolation from each other at that end. Heat generated in the inner pipe heats up the pipe contents, while heat generated in the outer pipe is lost to the environment.

The proximity effect with alternating current (AC) means that current in the inner pipe flows close to the outer surface of the pipe, and current in the outer pipe flows close to the inner surface. There is therefore no need for electrical isolation between the outer pipe and seawater. However, electrical isolation is essential in the annulus between the two pipes.

PIP systems have been used by Shell on Oregano, Serrano, Habanero, and Na Kika. The system is therefore considered field proven within length, depth, and power limitations of these projects.

The system is relatively simple with small number of components that may improve reliability compared to other systems. However, quality control is essential during construction and installation to avoid a short-circuit between the two pipes.



6.4.4. Indirect electrical heating**a. General**

Indirect electrical heating systems use a separate circuit of cables or conductors for current flow rather than the flowline. Cables or conductors are heated by applied current and heat flows into the flowline by thermal conduction.

b. Trace heating

A network of cables runs along the outside surface of the flowline in grooves cut into insulation. The cables are manifolded together at either end, usually in a three phase network. When voltage is applied, resistance of the cables causes the flowline to heat.

A three phase circuit is well suited for power supplies available on platforms and avoids power supply issues with the single phase supplies required for many other heating systems.

Trace heating cables are low resistance and relatively low voltage is required. Additional cables can be used as redundancy if some cables fail. The system is complex, however, and is only suited to onshore fabrication, in flexibles, bundles, or reeled pipe.

The only known offshore application is flexible risers. Integrated production bundles (IPBs) with trace heating were recently installed by Technip on Total Dalia. Qualification work has been completed on bundle and reeled pipe applications but no system has been installed to date.

6.4.5. Other flowline heating systems

Systems in a. and b. have been developed up to a point but have not yet been used in subsea flowline systems. All are indirect electrical heating systems where current flows through cables or conductors which heat up and subsequently heat flows into flowline.

a. Skin effect current tracing (SECT)

One or more small diameter (20 mm to 60 mm [0.8 in to 2.4 in]) ferromagnetic tubes are welded to the flowline. A heat resistant nonmagnetic electrical conductor runs through each tube and is electrically connected to the tube at one end. Current flows through the conductor and back through the tube. Current flow in the tube generates heat that flows into the flowline by thermal conduction.

The skin effect causes current to flow along the internal surface of the tube. Since no current is carried on the outside of the tube, the flowline is not electrically live. Therefore, the flowline may be earthed and there are no implications for cathodic protection (CP) systems.

The system is only suitable for onshore fabrication, preferably for bundles because reeling of a flowline with SECT tubes is not straightforward.

SECT heating systems have been used for simple submarine pipeline applications in short pipelines at refineries. Further qualification is required for subsea application.

b. Tube heating (induction)

Tube heating also uses ferromagnetic tubes with internal cables. In this case, cables are connected to each other at one end and electrically isolated from tubes. AC flows through each cable and produces an alternating magnetic field that induces circulating (eddy) currents in the tube wall. Circulating currents produce a heating



effect in the tube. Heat generated in the tube is dissipated through thermal conduction to the flowline.

Heating tubes do not form part of the primary electrical circuit and are free from any potential difference issues.

Cables can be connected in one or more three phase circuits readily suitable for platform supply.

The system is only suitable for onshore fabrication, preferably for bundles, because reeling of flowline with tubes is not straightforward. Aker Kvaerner has qualified the heating system as part of the Integrated Production Umbilical concept.

6.5. Chemical injection

6.5.1. General

- a. Chemical injection should be considered to control solids build up or corrosion in the pipeline.
- b. Chemical injection should be considered early in the design stage of a pipeline.
- c. Chemical injection systems shall be designed in accordance with GP 78-11.

Chemicals are normally injected at wellheads, although they are sometimes injected downhole. Chemicals are normally supplied through a small diameter pipeline or umbilical, which could be piggybacked onto a flowline, laid separately, or incorporated into a bundle. For deepwater systems, the chemical injection system is often mounted on a separate skid that may be retrieved by remotely operated vehicle (ROV) for maintenance or replacement.

- d. Compatibility between chemicals shall be established to ensure that the performance of one chemical does not adversely affect that of another.
- e. Compatibility shall be established between chemicals and all other materials that the chemicals may contact.
- f. Reliability and availability of the chemical injection system shall be predicted, taking due account of vendor performance data, anticipated flow conditions, composition of fluids, erosional effects, in-house data and experience, and anticipated inhibitor system availability.

6.5.2. Formation of wax

- a. Waxes form when the flowline operating temperature reduces below the wax appearance temperature.
- b. The primary means of wax management should be thermal insulation and/or routine pigging. However chemical injection may be required for wax management under all operating conditions.
- c. A wax management strategy should be developed after fluids testing and predictive modelling, in conjunction with the Flow Assurance and Production Chemistry disciplines.

Prevention of waxes may be achieved by continuous injection of wax inhibitor or wax dispersant chemicals. These chemicals can prevent precipitation of wax crystals or, more commonly, prevent their agglomeration and deposition. Continuous chemical injection can have very severe OPEX implications.



6.5.3. Formation of hydrates

- a. Hydrates can form in wet gas or multiphase pipelines under continuous or shutdown/start-up conditions. Hydrocarbon gas containing water will form hydrates under particular combinations of high pressure and low temperature.
- b. The hydrate formation tendency should be assessed by producing a hydrates “envelope” based on life-of-field fluids chemistry and pipeline operating conditions.
- c. Continuous injection of hydrate inhibitor is extremely OPEX intensive. In these circumstances, the primary means of hydrate management should be thermal insulation. However chemical injection may still be required for hydrate management under all operating conditions.

The final decision regarding chemical injection is often made by assessing OPEX against CAPEX on an NPV basis.

- d. A hydrates risk assessment and management strategy should be developed with the Flow Assurance and Production Chemistry disciplines.

Hydrates may be managed by thermal insulation or chemical injection.

Chemical options for preventing hydrates include injection of thermodynamic inhibitors, such as methanol and glycols, or “proprietary” low dosage hydrate inhibitors (LDHI).

One group of LDHI are kinetic hydrates inhibitors (KHI). KHIs prevent hydrates forming but are limited to a sub-cooling capacity of 8°C to 11°C (46°F to 52°F). In addition they have a limited performance time “window”; if a pipeline shuts down with KHI present, the inhibitor will lose its efficacy, typically within 48 hours, leaving the risk of hydrate formation afterwards.

The second type of LDHI are anti-agglomerants (AA). AAs have a greater effective sub-cooling capacity of 16°C to 19°C (61°F to 66°F). They require a continuous liquid phase to enable them to flow.

Pipelines which only go into the hydrates region during shutdown and start-up will only require batch dosing. Methanol or glycols are usually used but LDHIs are an option.

6.5.4. Corrosion

- a. Corrosion inhibitors form protective films on the surface of the pipewall. These films prevent corroding species, such as CO₂ reaction products, from contact with the metal surface.
- b. The treat rate for the inhibitor should be determined through laboratory testing which simulates the operating conditions of the pipeline as closely as possible. Field or trial data should be used where available.
- c. Pigging should be considered in order to achieve effective corrosion inhibition.

Distribution of inhibitor in gas pipelines is most commonly achieved by sphere pigging.

- d. Corrosion inhibitors may not distribute uniformly downstream of the injection point. Other means of corrosion protection may be necessary in these sections.
- e. A corrosion risk assessment and management strategy should be developed in conjunction with the Corrosion and Material Selection, Flow Assurance and Production Chemistry disciplines.



Typical inhibitors are film forming amines and imidazolines with smaller quantities of additives to enhance performance under specific conditions.

In multiphase pipelines, or flowlines upstream of processing facilities, water is always present and so the risk of corrosion is omnipresent. Corrosion inhibitor injection is required from day one and thereafter on a continuous basis.

The paramount requirement of a corrosion inhibitor is to be able to access the pipe wall on a continuous basis. The presence of deposits arising from scaling, corrosion, sand production and bacterial activity will prevent this and enable corrosion to occur under these deposits. Where possible, operational pigging can be used to clean the line and ensure both efficient operation and the efficacy of corrosion inhibition.

The presence of sand in pipelines provides another risk to effective corrosion inhibition. Corrosion inhibitors are surfactant by nature and can adhere to sand particles rather than the pipe wall. In addition, elevated velocities in the presence of sand can strip corrosion inhibitor films from the pipe wall.

- f. Further guidance on corrosion inhibitors is contained in GN 06-006.

6.5.5. Formation of mineral scales

- a. Scale inhibitors prevent build-up of scale on pipe internal surface.
- b. Scale inhibitors can sometimes be corrosive in their concentrated form (low pH) and so good distribution and mixing should be achieved at the injection point.

If required, scale inhibitors are normally injected either into wells or wellheads and are carried forward in the produced fluids.

- c. A scale risk assessment and management strategy should be developed in conjunction with the Flow Assurance and Production Chemistry disciplines.

The nature of materials and surfaces can impact the “stickability” of scales. For example, CRAs tend to give reduced scale adherence, whereas the carbon steels and higher surface roughness values tend to encourage greater scaling propensity.

6.5.6. Formation of microbial biofilms

- a. Bacteria should be prevented from contaminating subsea pipeline systems.
- b. A microbial risk assessment and management strategy should be developed in conjunction with the Flow Assurance and Production Chemistry disciplines.

Film forming inhibitors give poor performance against bacterial corrosion.

Micro-organisms are less likely to colonise in individual well flowlines or subsea collective flowlines as bacteria are not normally present in hot reservoirs. Systems can be contaminated by drilling and well intervention activities but this is less common as their procedures should specify the use of biocide treated fluids. However, monitoring systems and facilities for ad hoc biocide injection may be required when designing pipelines.

6.5.7. Drag reducing agents

- a. Drag reducing agents (DRAs) should be considered if a reduction in pressure drop along long pipelines or an increase in their volumetric throughput is required at some stage in the pipeline lifetime.

DRAs are normally high molecular weight polymers which reduce the turbulent drag between the pipeline fluids and the pipewall. They are normally injected

